



Summary of Public Comments and Responses for National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

Final rule; notice of final action on reconsideration.

**E.O. 12866 NESHAP for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters
2060-AR13 Final Rule 20120822**

December 2012

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**U. S. Environmental Protection Agency
Office of Quality Performance Standards
Sector Policies and Program Division
Energy Strategies Group (D243-01)
Research Triangle Park, NC**

FOREWORD

This document provides EPA's responses to public comments on EPA's Proposed National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters.

EPA published a notice of reconsideration and proposed amendments of the standards applicable to industrial, commercial, and institutional boilers and process heaters in the Federal Register on December 23, 2011 (76 FR 80598). EPA received comments on these proposed rules via mail, e-mail, and facsimile. Copies of all comments submitted are available at the EPA Docket Center Public Reading Room and are also available electronically through <http://www.regulations.gov> by searching Docket ID EPA-HQ-OAR-2002-0058.

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

EPA's responses to comments are generally provided immediately following each comment excerpt. However, in instances where several commenters raised similar or related issues, EPA has provided a single response after the first comment excerpt in the group and referenced this response in the other comment excerpts.

Parallel with this rulemaking effort are three separate, but related rulemakings that may be of interest to stakeholders. These three rules are: *National Emission Standards for Hazardous Air Pollutants for Area Source Industrial/Commercial/Institutional Boilers* (Docket ID: EPA-HQ-OAR-2006-0790); *Identification of Non-Hazardous Secondary Materials That Are Solid Waste* (Docket ID: EPA-HQ-RCRA-2008-0329); and *Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Commercial and Industrial Solid Waste Incineration Units* (Docket ID: EPA-HQ-OAR-2003-0119).

Given the identical proposal dates, and the related nature of these other rules, many commenters submitted comments to this rulemaking docket that were specific to one of these related rulemakings. Some commenters submitted a single DCN with comments on all four rules while others submitted a separate DCN specific to each rule. Many commenters submitted identical comments to all of these dockets. In order to reduce duplicative comments, this document flags comments associated with any of the above three related rulemakings as out-of-scope comments for this response to comment document. To the extent that the commenter submitted these comments to the appropriate rulemaking document, responses have been developed in the response to comment documents for each of these related rulemakings. For this reason, EPA encourages the public to read the other response to comment documents prepared for these three other rulemakings as they may contain topics relevant to these other rulemakings.

The primary contact regarding questions or comments on this document is:

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U.S. Environmental Protection Agency

OAQPS/Sector Policies and Programs Division

Energy Strategies Group (D243-01)

Research Triangle Park, North Carolina 27711

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Legal and Applicability Issues

2A. Authority for Emission Credits

Commenter Name: Jessica Bridges

Commenter Affiliation: United States Clean Heat & Power Association (USCHPA)

Document Control Number: EPA-HQ-OAR-2002-0058-3501-A1

Comment Excerpt Number: 23

Comment: We are supportive of this use of emission credits obtained from energy conservation measures.

Response: The EPA thanks the commenter for their support.

Commenter Name: Myra Reece

Commenter Affiliation: South Carolina Department of Health and Environmental Control

Document Control Number: EPA-HQ-OAR-2002-0058-3629-A2

Comment Excerpt Number: 2

Comment: The EPA Should Provide A Clear Process To Determine Acceptability Of Benchmarks

Section 63.7533 requires facilities opting to use the emission credit approach to establish an emissions benchmark from which emission reduction credits may be generated. Credits are generated by the difference between the benchmark that is established for each affected boiler, and the actual energy demand reductions from energy conservation measures implemented after January 1, 2008. According to the proposed rule, the benchmark shall be determined by using the most representative, accurate, and reliable process available for the source.

The EPA does not provide specific parameters to determine what constitutes an acceptable benchmark. However, the October 10, 2010, EPA guidance document titled “Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Industrial, Commercial, and Institutional Boilers” states that “the U.S. EPA’s ENERGY STAR Program has developed benchmarking tools that establish best-in-class for specific industrial sectors” and encourages industry to use these tools.

DHEC requests that the EPA provide in the rule the acceptable benchmarks in order to establish a level playing field for all facilities using this compliance approach, and to minimize the resources required by the delegated agencies to review and approve the NOCS. In addition to updating the rule, we believe the EPA should develop and make available guidance examples demonstrating the implementation of the emission credit compliance option.

Response: We believe that the benchmark, as used in the rule, can be easily determined. Benchmark is defined in the rule as:

Benchmark means the fuel use for a boiler or process heater for the one-year period before the date that an energy demand reduction occurs, unless it can be demonstrated that a different time period is more representative of historical operations.

Benchmarking under the EPA's ENERGY STAR is more difficult because it involves determining energy output and energy use, whereas in 63.7533, the requirement is to benchmark the fuel use of the affected boiler which can be easily determined. In terms of guidance on calculating energy credits, the Department of Energy has prepared guidance which has been posted to the EPA's Boiler MACT webpage.

Commenter Name: Myra Reece

Commenter Affiliation: South Carolina Department of Health and Environmental Control

Document Control Number: EPA-HQ-OAR-2002-0058-3629-A2

Comment Excerpt Number: 3

Comment: DHEC also requests that the EPA clarify how to assign emission credits generated from process efficiencies that might well affect more than one boiler or process heater. Should emission credits be dedicated to a single boiler or process heater?

Response: As part of the required Implementation Plan that the source must develop and submit for approval, the source is to identify the affected boiler to which the emission credits will be applied, and to document all uses of energy from the identified affected boiler. It is the only improvement made to systems using energy from the identified affected boiler.

Commenter Name: Ahmed Idriss, Capital Power Corporation

Commenter Affiliation: CPI USA North Carolina (CPI NC)

Document Control Number: EPA-HQ-OAR-2002-0058-3524-A1

Comment Excerpt Number: 8

Comment: CPI NC is confused by the EPA's decision to grant energy credits for steam-output based emission limits but not electricity output-based emission limits. Such a position creates an unfavorable market bias against facilities that do not produce steam, making such facilities less economic to run. Further, it does not provide incentive for such facilities to make modifications leading to energy efficiencies.

CPI NC recommends the Proposed Rule be amended to also provide energy credits for electricity output-based emission limits.

Response: We agree that the emission credit provision should be available for the electricity output-based emission limits. When section 63.7533 was promulgated in the March 2011 final rule, the output-based limits were only in terms of steam output. In the December 2011 reconsideration proposal, the steam output-based limits were also listed in terms of Mwh output, but 63.7533(a) was inadvertently not revised. In the final rule, 63.7533(a) has been revised to read "If you elect to comply with the alternative equivalent output-based emission limits ..."

2B. Waste Heat Boilers and Process Heaters

Commenter Name: Russell A. Wozniak

Commenter Affiliation: The Dow Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3449-A1

Comment Excerpt Number: 35

Comment: EPA should revise the definition of Boiler to clearly exclude all waste heat boilers from coverage under this regulation.

The last sentence in the proposed definition of "Boiler" says that waste heat boilers that use only natural gas, refinery gas, or other gas 1 fuels for supplemental fuel are excluded from this definition. In addition, EPA should also exclude waste heat boilers that are fueled with gas 2 fuels in the rare case that a gas 2 fuel is used as supplemental fuel in a waste heat boiler. Table 3 of EPA's Miscellaneous Proposed Technical Corrections describes this change as "Revise the definition of waste heat boiler to clarify that the definition includes fired and unfired waste heat boilers", which leads one to believe that all waste heat boilers should be excluded from the regulation.

EPA should replace the last sentence of the proposed new definition of Boiler with the text from the March 21, 2011 final rule, which reads: "Waste heat boilers are excluded from this definition". This change would better reflect the intent of EPA which is to exempt these types of units from coverage under this MACT rule.

Response: The change suggested by the commenter is being incorporated into the final rule. Waste heat boilers was first proposed to be exempted from the Boiler MACT in the original 2003 proposal. The rationale (see 68 FR 1669) was that the proposed rule did not regulate emissions from combustion units with waste heat boilers, unless such units would otherwise be subject to the proposed rule. Waste heat boilers and heat recovery steam generators are not a boiler as defined in the rule and were never part of the source category because waste heat boilers do not combust fuel. Waste heat boilers are heat exchangers that do not have their own firebox but use the heat of hot waste gases from industrial (e.g., thermal oxidizers, kilns, furnaces) or power equipment (e.g., gas turbine, engines) to generate steam. The definition of "Waste heat boiler" in the final rule has also been revised to clarify what is meant by "fired and unfired." Duct burners, which are mounted in a duct or discharging into a duct, are sometimes used to increase the temperature of the hot exhaust gas from a combustion turbine to increase electricity output from a combined cycle gas turbine system.

Commenter Name: Russell A. Wozniak

Commenter Affiliation: The Dow Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3449-A1

Comment Excerpt Number: 36

Comment: The last sentence in the proposed definition of "Process Heater" says that Waste heat process heaters that use only natural gas, refinery gas, or other gas 1 fuels for supplemental fuel are excluded from this definition. In addition, EPA should also exclude waste heat process heaters that are fueled with gas 2 fuels in the rare case that a gas 2 fuel is used as supplemental

fuel in a waste heat process heater. Table 3 of EPA's Miscellaneous Proposed Technical Corrections describes this change as "Revise the definition of waste heat process heater to clarify that the definition includes fired and unfired waste heat process heaters", which leads one to believe that all waste heat process heaters should be excluded from the regulation.

EPA should replace the last sentence of the proposed new definition of Process Heater with the following text:

"Waste heat process heaters are excluded from this definition".

This change would better reflect the intent of EPA which is to exempt these types of units from coverage under this MACT rule.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3449-A1, excerpt 35.

Commenter Name: Paul G. Page

Commenter Affiliation: AK Steel Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3457-A2

Comment Excerpt Number: 1

Comment: In the proposed Reconsideration Rule, it appears that EPA understands our concerns and is seeking to implement sound policy by exempting process gas-fired units, albeit with qualifications, from the Boiler MACT. To that end, EPA has proposed the following exemption criteria:

- Blast furnace gas-fired boilers or process heaters that receive 90 percent or more of their total annual gas volume from blast furnace gas;
- Waste heat boilers that use only natural gas, refinery gas, or other gas 1 fuels for supplemental fuel;
- Waste heat process heaters that use only natural gas, refinery gas, or other gas 1 fuels for supplemental fuel;
- Any boiler or process heater that is part of the affected source subject to another NESHAP in 40 C.F.R. part 63; and
- Any boiler or process heater that is used as a control device to comply with another subpart of part 60, 61 or 63, provided that at least 50 percent of the heat input to the boiler or process heater is provided by the gas stream that is regulated under another subpart.

While AK Steel supports these exemptions and EPA's effort to provide them, they are limited in their scope and benefit. As a practical matter, AK Steel is uncertain as to how we can verify the applicability of these exemption criteria to our process operations without further clarification from EPA.

Response: The EPA thanks the commenter for their support. Several of the exemption in 63.7491 have been revised to better clarify the scope of the exemption. See the response to comment EPA-HQ-OAR-2002-0058-3449-A1, excerpt 35 regarding changes to waste heat boiler exemption.

Commenter Name: Paul G. Page
Commenter Affiliation: AK Steel Corporation
Document Control Number: EPA-HQ-OAR-2002-0058-3457-A2
Comment Excerpt Number: 4

Comment: At one of AK Steel's facilities, the Company utilizes four waste heat boilers. Each waste heat boiler is associated with a corresponding slab reheat furnace and receives waste heat from that slab reheat furnace as a component of its heat input. The waste heat boilers only operate when their associated slab reheat furnace is operating so at all times they are truly functioning as waste heat boilers. The waste heat boilers combust blended coke oven gas as a supplemental fuel.

Prior to the proposed Reconsideration Rule, these waste heat boilers were exempt without qualification. Under the proposed Reconsideration Rule, the waste heat boilers are only exempt if their supplemental fuel meets the "other gas 1 fuel" criteria.

Response: See response to comment EPA-HQ-OAR-2002-0058-3449-A1, excerpt 35.

Commenter Name: Peter Pagano
Commenter Affiliation: American Iron and Steel Institute (AISI)
Document Control Number: EPA-HQ-OAR-2002-0058-3490-A1
Comment Excerpt Number: 2

Comment: It appears in the Reconsidered Rule that EPA understands our concerns and is seeking to implement sound policy by exempting units used to control process gases from the Boiler MACT. To that end, EPA has exempted, with qualifications, the following:

- Blast furnace gas fuel-fired boilers or process heaters that receive 90 percent or more of their total annual gas volume from blast furnace gas
- Waste heat boilers that use only natural gas, refinery gas, or other gas 1 fuels for supplemental fuel,
- Waste heat process heaters that use only natural gas, refinery gas, or other gas I fuels for supplemental fuel,
- Any boiler or process heater that is part of the affected source subject to another NESHAP in 40 C.F.R. part 63; and
- Any boiler or process heater that is used as a control device to comply with another subpart of part 60, 61 or 63, provided that at least 50 percent of the heat input to the boiler or process heater is provided by the gas stream that is regulated under another subpart.
- While we strongly support these exemptions and EPA's efforts, they fall short of encouraging the continued beneficial reuse of process gases by the iron and steel industry.

Response: The EPA thanks the commenter for their support. Several of the exemptions in 63.7491 have been revised in the final rule to better clarify the exemption. See the response to comment EPA-HQ-OAR-2002-0058-3449-A1, excerpt 35.

Commenter Name: Peter Pagano
Commenter Affiliation: American Iron and Steel Institute (AISI)
Document Control Number: EPA-HQ-OAR-2002-0058-3490-A1
Comment Excerpt Number: 4

Comment: Clarification regarding supplemental fuel in the definitions of "boiler" and "process heater" also is necessary.

As currently written, the use of coke oven gas in a waste heat boiler/process heater could negate the exclusion. The definitions of "boiler" and "process heater" exclude only waste heat boilers and waste heat process heaters "that use only natural gas, refinery gas, or other gas I fuels for supplemental fuel. " The preamble further clarifies that these units can include supplemental burners as long as those burners combust only gas 1 fuels, up to 50% of their heat input, without voiding the exclusion. Because coke oven gas may not meet the current proposed definition of a gas I fuel, coke oven gas may not be able to be used in a waste heat boiler or process heater without voiding the exclusion.

As discussed in our previous comments,¹³ this makes no sense and is contrary to EPA's intended goals in promulgating the rule. Coke oven gas is an efficient fuel that can replace natural gas as a supplemental fuel. The coke oven gas will be combusted elsewhere if not used in a boiler or process heater, so there is no environmental benefit to excluding it from use in one of these units. EPA should not discourage the use of coke oven gas in a waste heat boiler or process heater just because the supplemental fuel contains a process gas other than natural gas, refinery gas, or a gas 1 fuel.

[Footnote]

(13) Initial Comments, at 12.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3449-A1, excerpt 35.

Commenter Name: Lorraine Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1
Comment Excerpt Number: 121

Comment: EPA is proposing to amend the definition of boiler and process heater to clarify that waste heat boilers and process heaters are not covered by the Boiler MACT.

ACC appreciates the clarification that waste heat boilers are not covered, and support the exemption for waste heat boilers with supplemental burners. The last sentence in the proposed definition of "Boiler" states that waste heat boilers that use only natural gas, refinery gas, or other gas 1 fuels for supplemental fuel are excluded from this definition. EPA should also exclude waste heat boilers that are fueled with gas 2 fuels in the rare case that a gas 2 fuel is used as supplemental fuel in a waste heat boiler. Preamble Table 3, which lists EPA's Miscellaneous Proposed Technical Corrections, describes this change as "Revise the definition of waste heat

boiler to clarify that the definition includes fired and unfired waste heat boilers," which leads one to believe that all waste heat boilers should be excluded from the regulation.

EPA should replace the last sentence of the proposed new definition of boiler with the text from the Final Boiler Rule, which reads: "Waste heat boilers are excluded from this definition." (See 76 Fed. Reg. 15686.) EPA should similarly change the definition of process heater. This change would better reflect the EPA's intent to exempt these types of units from coverage under this MACT rule. In addition, although the preamble text cited above mentions a 50 percent heat input cutoff for supplemental burners, this criteria is not included in the boiler or process heater definitions, and it is unclear as to the necessity or the basis of such criteria. ACC comments again that all waste heat boilers and all waste heat process heaters should clearly be excluded from this rule.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3449-A1, excerpt 35.

Commenter Name: Bruce A. Steiner

Commenter Affiliation: American Coke and Coal Chemical Institute (ACCCI)

Document Control Number: EPA-HQ-OAR-2002-0058-3547-A2

Comment Excerpt Number: 4

Comment: Clarification regarding supplemental fuel in the definitions of "Boiler" and "Process Heater" is also necessary. As currently written, the use of coke oven gas in a waste heat boiler/process heater would negate the exclusion. The definitions of "boiler" and "process heater" exclude only waste heat boilers and waste heat process heaters "that use only natural gas, refinery gas, or other Gas 1 fuels for supplemental fuel." The preamble further clarifies that these units can include supplemental burners as long as those burners combust only Gas 1 fuels, up to 50% of their heat input, without voiding the exclusion. Coke oven gas, however, is neither a natural gas, refinery gas, nor Gas 1 fuel. Its use in these units, therefore, would void the exclusion.

ACCCI raised concerns about this issue in our comments on the original rule and we repeat those concerns here. It makes no sense to discourage the use of coke oven gas in a waste heat boiler or process heater just because the supplemental fuel contains a process gas other than natural gas, refinery gas, or a Gas 1 fuel. Coke oven gas is an efficient fuel that can replace natural gas as a supplemental fuel. The coke oven gas will be combusted elsewhere if not used in a boiler or waste heat boiler, so there is no environmental benefit to excluding it from use in a boiler. In fact, coke oven gas will most likely be combusted in a flare, which is less efficient than a boiler or waste heat boiler and will result in increased emissions to the environment based on this reduced efficiency.

In summary, we urge EPA to modify the definitions "waste heat boiler" and "waste heat processor" to include those units designed to use process gases as fuel. We also request clarification that coke oven gas can be used in a supplemental burner in a waste heat boiler or process heater without voiding the exclusions.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3449-A1, excerpt 35.

Commenter Name: Paul G. Page
Commenter Affiliation: AK Steel Corporation
Document Control Number: EPA-HQ-OAR-2002-0058-3457-A2
Comment Excerpt Number: 6

Comment: If the definition of "waste heat boiler" is not revised to properly include the use of process gases, then further revisions will be necessary to clarify the "supplemental fuel" provisions of the exemption.

For example, in order to meet the "other gas 1 fuel" criteria, the "fuel" must have a mercury concentration less than 40 $\mu\text{g}/\text{m}^3$. The fuel combusted in AK Steel's waste heat boilers is a mixture of coke oven gas combined with natural gas diluted with air. The natural gas is diluted with air to bring its heating value to a comparable level with the coke oven gas (around 500 BTu/cf). This mixed gas is then supplemented with natural gas, as needed based on pressure, depending on the waste heat boiler's output requirements and the coke oven gas availability. Accordingly, the ratio of the fuel components as combusted in the waste heat boilers is continually changing. Therefore, the "fuel" is constantly changing depending on the operational variables, including boiler output requirements and coke oven gas availability.

AK Steel has also identified significant variability on mercury concentration in coke oven gas. AK Steel collected three samples of the coke oven gas prior to mixing over a three-day period and the results were 126.674 $\mu\text{g}/\text{m}^3$, 40.827 $\mu\text{g}/\text{m}^3$, and 24.006 $\mu\text{g}/\text{m}^3$. Notwithstanding these results, AK Steel presumes that the mixed fuel as combusted is below the 40 $\mu\text{g}/\text{m}^3$ exemption criteria threshold. However, AK Steel is unable to sample the mixed fuel as combusted at this time to confirm that, thus further complicating the analysis.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3449-A1, excerpt 35.

Commenter Name: Richard Krock
Commenter Affiliation: The Vinyl Institute
Document Control Number: EPA-HQ-OAR-2002-0058-3526-A1
Comment Excerpt Number: 18

Comment: Waste Heat Units Using Gas 1 Fuels Are Not Boilers or Process Heaters

EPA amended the proposed definition of "process heater" to exclude "waste heat process heaters that use only natural gas, refinery gas, or other gas 1 fuels for supplemental fuel." The VI supports the revised definition, which mirrors the definition for "boiler." EPA also clarified that waste heat boilers and process heaters may use Gas 1 fuels for supplemental fuel and still remain outside the requirements of Subpart DDDDD. However, VI does not support EPA's clarification that waste heat boilers with supplemental Gas 1 firing greater than 50% would become regulated boilers. As EPA states in the final rule preamble (Page 15617 of 3/21/10 final rule), all waste heat boilers should be exempted to encourage use of these energy saving devices and ensure valuable fuel gases are used for energy recovery rather than wasted.

The VI supports these exclusions because it would be inappropriate to apply emission standards for traditional boilers and process heaters to waste heat boilers and process heaters, which have a

substantially different configuration and therefore have substantially different emission profiles and require substantially different emission controls. Furthermore, waste heat boilers and process heaters provide a significant energy efficiency and pollution prevention opportunity over conventional units. Waste heat units burn less fuel than conventional units, resulting in lower overall emissions.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3449-A1, excerpt 35.

Commenter Name: Erika Frank

Commenter Affiliation: Calgon Carbon Corp.

Document Control Number: EPA-HQ-OAR-2002-0058-3680-A2

Comment Excerpt Number: 1

Comment: Generally, Calgon Carbon supports the waste heat exemption from the Major Source Boiler Rule because it encourages the use and re-use of heat and steam, which in turn reduces fossil fuel combustion and conserves valuable energy at industrial facilities. However, the scope of the waste heat boiler exemption remains unclear. When the Major Source Boiler Rule was finalized in March 2011, EPA removed any limitation on the amount of heat provided by supplemental burners in order to be considered a "waste heat boiler." EPA deleted the 50 percent criterion that appeared in a prior version of the rule, and also indicated in the comment response document that EPA was modifying the definition of waste heat boiler to include "all waste heat boilers instead of considering only those units with 50 percent or more of their waste heat." EPA further indicated in the comment response document that "[a]ll waste heat boilers have been exempted from [the March 2011 final rule], regardless of the heat input contribution from duct burners or other sources." In contrast, the preamble to the December 2011 proposed revisions seems to once again impose a 50 percent criterion. In the December 2011 preamble, EPA explained that waste heat boilers "can include supplemental burners as long as those burners combust only Gas 1 fuels, up to 50 percent of their heat input." This language appears to reintroduce the 50 percent criterion. This is especially confusing because EPA did not propose to revise the actual text of the regulatory provisions in this regard, and EPA did not otherwise indicate intent to reinsert the 50 percent criterion into the definition of either "boiler" or "waste heat boiler." Please reaffirm that all waste heat boilers and process heaters are exempt from the Major Source Boiler Rule, regardless of the heat input contribution from duct burners or other sources. We also request that EPA make the following changes to the December 2011 proposed definition of "waste heat boiler":

Waste heat boiler means a device that recovers any amount of normally unused energy and converts it to usable heat, regardless of the heat input contribution from supplemental burners and other sources. A waste heat boiler can include supplemental burners that use only natural gas, refinery gas, or other gas 1 fuels. Waste heat boilers are also referred to as heat recovery steam generators. This definition includes both fired and unfired waste heat boilers.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3449-A1, excerpt 35.

Commenter Name: Monica Lopes

Commenter Affiliation: NAES Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3808-A1

Comment Excerpt Number: 1

Comment: Although EPA has attempted to clarify the applicability of the rule to duct burners installed in waste heat boilers, there is still a discrepancy between the information provided in Section K2 of the preamble (page 80616) and the information provided in the definition of “Boiler” on page 80650 that warrants further clarification. While the preamble language states that “ We also are clarifying that waste heat boilers and process heaters can include supplemental burners as long as those burners combust only Gas 1 fuels, up to 50 percent of their heat input”, the definition of boiler does not seem to mention the same heat input restriction: “Waste heat boilers that use only natural gas, refinery gas, or other gas 1 fuels for supplemental fuel are excluded from this definition.” Please confirm that “all fired waste heat boilers that use only natural gas, refinery gas, or other gas 1 fuels for supplemental fuel” are exempt from the major source boiler MACT rule regardless of the duct burner heat input rate.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3449-A1, excerpt 35.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 136

Comment: EPA is proposing to amend the definition of boiler and process heater to clarify that waste heat boilers and process heaters are not covered by the Boiler MACT.

We appreciate the clarification that waste heat boilers are not covered, and support the exemption for waste heat boilers with supplemental burners. However, we request that EPA revise the definitions to exclude the limitation on the fuels that may be burned in supplemental burners on waste heat boilers to qualify for the exemption. In addition, although the preamble text cited above mentions a 50 percent heat input cutoff for supplemental burners, this criterion is not included in the boiler or process heater definitions, and we are unclear as to the necessity for or the basis of it.

Response: The EPA thanks the commenter for their support. See the response to comment EPA-HQ-OAR-2002-0058-3449-A1, excerpt 35.

Commenter Name: Barry Christensen

Commenter Affiliation: Occidental Chemical Corporation (OCC)

Document Control Number: EPA-HQ-OAR-2002-0058-3477-A1

Comment Excerpt Number: 7

Comment: OCC supports the exclusion of *all* gas-fired waste heat boilers (WHBs) from the final rule. The proposed revision limits the exclusion to units using only natural gas, refinery gas, or other gas 1 fuels. Use of WHBs provides a significant energy efficiency and pollution prevention opportunity over conventional units because they burn less fuel, which results in lower overall emissions. Therefore, these energy saving units should be encouraged by EPA’s regulations and not restricted, as explained on preamble page 15617 of the final rule.

For example, several OCC sites utilize onsite cogeneration steam turbine facilities which operate with waste heat boilers and a common stack. These WHBs are generally referred to as heat recovery steam generators, or HRSGs. Some of these HRSGs are capable of being supplementally-fired with natural gas and/or hydrogen gas (a gaseous co-product) and consequently are currently classified as Gas 2 sources. Generally it is not possible to separate the combustion turbine emissions (or those from any other primary source) from those associated with the HRSG due to their integrated design and single exhaust stack configuration. Therefore, a regulation that contains emission limitations for supplementally-fired waste heat boilers is not practical because it is not possible to operate the WHBs without the turbines or any other fired source to conduct compliance testing. In this case, these WHBs should be regulated under the National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines (40 CFR Part 63, Subpart YYYY), if at all, rather than the Boiler and Process Heater MACT standard. Another similar example includes units subject to the Hazardous Waste Combustion MACT where WHB's are often used. Therefore, emissions from all combustion units with supplementally-fired waste heat boilers are most appropriately regulated by the applicable standards for the primary combustion source and should be expressly excluded from this proposed rule for major source boilers.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3449-A1, excerpt 35.

Commenter Name: Richard Krock

Commenter Affiliation: The Vinyl Institute

Document Control Number: EPA-HQ-OAR-2002-0058-3526-A1

Comment Excerpt Number: 19

Comment: Measuring emissions from these units would also be impracticable because of their varying operation and their integration into other fired units. For example, some VI members utilize onsite cogeneration facilities with steam turbines with waste heat boilers. These waste heat boilers are generally referred to as heat recovery steam generators (HRSGs). Some of these HRSGs are capable of being supplementally-fired with natural gas and/or hydrogen gas (or other gaseous co-products). Generally, it is not possible to separate the combustion turbine emissions (or those from another primary source) from those associated with the HRSG. Thus, measuring emissions for supplementally-fired waste heat boilers is not practicable because it is not possible to operate the waste heat boilers without the turbines or other fired source to conduct compliance testing.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3449-A1, excerpt 35.

Commenter Name: Richard Krock

Commenter Affiliation: The Vinyl Institute

Document Control Number: EPA-HQ-OAR-2002-0058-3526-A1

Comment Excerpt Number: 20

Comment: These waste heat boilers may be regulated under other MACT standards, which would also exclude them from regulation under the Boiler MACT. Indeed, in an earlier version of the Boiler MACT that was later vacated by the U.S. Court of Appeals for the District of Columbia Circuit on other grounds, EPA was clear on this point: "emissions from a combustion

unit with a waste heat boiler are regulated by the applicable standards for the particular type of combustion unit.”³⁰ The VI agrees that emissions from combustion units with supplementally-fired waste heat boilers are most appropriately regulated by the applicable standards for the primary combustion source.

[Footnotes]

30 69 Fed. Reg. 55,218, 55,222 (Sept. 13, 2004).

Response: See the response to comment EPA-HQ-OAR-2002-0058-3449-A1, excerpt 35.

Commenter Name: Erika Frank

Commenter Affiliation: Calgon Carbon Corp.

Document Control Number: EPA-HQ-OAR-2002-0058-3680-A2

Comment Excerpt Number: 2

Comment: If EP A is indeed reintroducing the 50 percent criterion, then the relevant definitions (i.e., "boiler," "process heater," "waste heat boiler," and "waste heat process heater") should be revised so that the delineation of heat input to a unit utilizing waste heat is based on an annual average. Such a revision would promote both clarity and consistency, as several definitions in the March 2011 final rule are already based on the annual heat input to the unit, including, for example, "blast furnace gas fueled boiler or process heater," "unit designed to burn gas 2 (other) subcategory," and "unit designed to burn coal." If EPA intends to reintroduce the 50 percent criterion, we request that EPA make the following alternative changes to the December 2011 proposed definition of "waste heat boiler":

Waste heat boiler means a device that recovers normally unused energy and converts it to usable heat. A waste heat boiler can include supplemental burners that use only natural gas, refinery gas, or other gas 1 fuels. up to 50 percent of their heat input on an annual average. Waste heat boilers are also referred to as heat recovery steam generators. This definition includes both fired and unfired waste heat boilers.

Response: We disagree with the commenter's suggestion on how to revise the definition of waste heat boiler. See the response to comment EPA-HQ-OAR-2002-0058-3449-A1, excerpt 35 on how the definition is being revised.

Commenter Name: Barry Christensen

Commenter Affiliation: Occidental Chemical Corporation (OCC)

Document Control Number: EPA-HQ-OAR-2002-0058-3477-A1

Comment Excerpt Number: 9

Comment: The preamble page 80616 states, “We also are clarifying that waste heat boilers and process heaters can include supplemental burners as long as those burners combust only Gas 1 fuels, up to 50 percent of their heat input.” At the same time, the definition of rated heat input excludes “heat input provided by preheated combustion air, recirculated flue gases, or exhaust gases from other sources such as gas turbines, internal combustion engines, kilns, etc.” Therefore, we seek clarification regarding what is the exact method of calculation concerning the

50% limit mentioned in the preamble – i.e. as total rated heat input or just the fuel fired heat input. This preamble clarification, which is not in the proposed rule, may make most natural gas fired WHBs subject to the rule, which is contrary to the definition of boiler and process heater, which excludes them. As noted above, it is not possible to separate turbine emissions from HRSG emissions to do stack sampling, so even Gas 2 fired WHB units cannot be stack sampled.

Response: The reference to the 50% limit has been deleted. See the response to comment EPA-HQ-OAR-2002-0058-3449-A1, excerpt 35.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 18

Comment: Waste heat boilers that use only natural gas, refinery gas or other gas 1 fuels are excluded from the definitions of boiler and process heater. Since proposed §63.7491(i) excludes control devices, gases subject to other part 63 subparts or part 60, 61 or 65 subparts should also be allowed to be combusted in a waste heat boiler or process heater without making that waste heat system a boiler or process heater. Under the proposed definitions combustion of any such gas would negate the waste heat exception and sources would therefore be discouraged from recovering the energy from such regulated gases in waste heat boilers or process heaters.

Response: A waste heat boiler, or heat recovery steam generator, is an enclosed device without fuel combustion. The heat input to the unit is the hot exhaust gas from industrial and power equipment. The temperature of the incoming exhaust gas is sometimes increased by the use of a duct burner located upstream from the waste heat boiler. Also, the incoming hot gas may be the exhaust from a thermal oxidizer used to treat off-gases. We agree with the commenter and the definition of "boiler" and "process heater" have been revised in the final rule to excluded all waste heat units from those definition because a waste heat boiler does not meet the definition of a boiler since it is not an enclosed device using controlled flame combustion.

Commenter Name: Erika Frank

Commenter Affiliation: Calgon Carbon Corp.

Document Control Number: EPA-HQ-OAR-2002-0058-3680-A2

Comment Excerpt Number: 3

Comment: EPA should clarify that in the context of waste heat boilers, the term "supplemental burners" means burners that introduce fuel directly into the combustion unit where the heat recovery is also located. Burners that introduce fuel in an upstream combustion unit (e.g., incinerator, thermal oxidizer, or afterburner) are part of the upstream combustion unit that is not a "boiler" because it has no heat recovery. Subsequent recovery of the waste heat in a downstream unit does not render the upstream combustion unit a "boiler."

Response: The definition of "Waste heat boiler" has been revised in the final rule to clarify that a "waste heat boiler" is a boiler without its own firebox (i.e., internal burners) which uses the heat of hot exhaust gases from industrial or power (e.g., gas turbine) equipment to generate

additional steam. The temperature of the exhaust gas to the waste heat boiler is increased in some cases by the installation of burners (i.e., duct burners) in the duct upstream from the waste heat boiler.

Commenter Name: Monica Lopes
Commenter Affiliation: NAES Corporation
Document Control Number: EPA-HQ-OAR-2002-0058-3808-A1
Comment Excerpt Number: 2

Comment: Please clarify if liquid fuel burned for periodic testing not to exceed a combined total of 48 hours during any calendar year or during periods of gas curtailment or gas supply emergencies would also be included in this exemption of “all fired waste heat boilers that use only natural gas, refinery gas, or other gas 1 fuels for supplemental fuel.”

Response: The exemption has been revised to remove the criteria of the type of fuels used for supplement. See the response to comment EPA-HQ-OAR-2002-0058-3449-A1, excerpt 35.

Commenter Name: Monica Lopes
Commenter Affiliation: NAES Corporation
Document Control Number: EPA-HQ-OAR-2002-0058-3808-A1
Comment Excerpt Number: 3

Comment: The proposed area source Boiler MACT rule seem to exclude all fired and unfired waste heat boilers from the definition of boiler, regardless of the type of fuel fired in the duct burners. Please clarify EPA’s rationale for not making the same exclusion under the major source Boiler MACT rule since these duct burners are typically installed after gas turbines, do not operate independently of the gas turbines, and therefore, their emissions will be combined with the gas turbine emissions thus making it difficult for facilities to demonstrate compliance with the limits that apply only to the duct burners, regardless of the type of fuel fired in the duct burners.

Response: See the response to comment EPA-Hq-OAR-2002-0058-3449-A1, excerpt 35

Commenter Name: Jessica Bridges
Commenter Affiliation: United States Clean Heat & Power Association (USCHPA)
Document Control Number: EPA-HQ-OAR-2002-0058-3501-A1
Comment Excerpt Number: 27

Comment: 40 CFR 63.7575, Revise the definition of “process heater” to include “units heating hot water as a process heat transfer medium” and to clarify that “waste heat process heaters are excluded from this definition” similar to the exemption allowed for waste heat boilers. This is appropriate.

Response: The EPA thanks the commenter for their support.

Commenter Name: Jessica Bridges
Commenter Affiliation: United States Clean Heat & Power Association (USCHPA)
Document Control Number: EPA-HQ-OAR-2002-0058-3501-A1
Comment Excerpt Number: 29

Comment: 40 CFR 63.7575, Revise the definition of “waste heat boiler” to clarify that the definition includes fired and unfired waste heat boilers. This is appropriate.

Response: The EPA thanks the commenter for their support.

Commenter Name: Jessica Bridges
Commenter Affiliation: United States Clean Heat & Power Association (USCHPA)
Document Control Number: EPA-HQ-OAR-2002-0058-3501-A1
Comment Excerpt Number: 30

Comment: 40 CFR 63.7575, Revise the definition of “waste heat process heater” to clarify that the definition includes fired and unfired waste heat process heaters. This is appropriate.

Response: The EPA thanks the commenter for their support.

Commenter Name: Timothy Serie
Commenter Affiliation: American Coatings Association (ACA)
Document Control Number: EPA-HQ-OAR-2002-0058-3502-A1
Comment Excerpt Number: 12

Comment: ACA generally supports the following proposed changes in the Boiler MACT rule:

Exclusion of waste heat boilers and process heaters

Response: The EPA thanks the commenter for their support.

Commenter Name: Matthew Todd
Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)
Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2
Comment Excerpt Number: 19

Comment: The proposed clarifications to the definitions of "Boiler," "Waste Heat Boiler" and "Process Heater" are very helpful and should be finalized.

EPA has proposed some very helpful clarifications to be clear that waste heat boilers and waste heat process heaters are exempt from the boiler and process heater requirements and these changes should be finalized.

Response: The EPA thanks the commenter for their support.

Commenter Name: David Gardiner
Commenter Affiliation: The Alliance for Industrial Efficiency
Document Control Number: EPA-HQ-OAR-2002-0058-3683-A2
Comment Excerpt Number: 7

Comment: We Commend EPA for Exempting Waste Heat Process Heaters from the Standards.

In the December rule, EPA clarifies that waste heat process heaters are not subject to emissions limits.²² We are grateful for this exemption, as waste heat process heaters are essentially heat exchangers that capture heat from waste gas and convert it into heat or hot water to support an industrial process. EPA has encouraged this energy efficiency improvement by exempting such waste heat process heaters from the emissions standards of the Industrial Boiler MACT. We urge the Agency to retain this exemption in the final rule.

[Footnote 22: 76 Fed. Reg. at 80616 (“...waste heat process heaters, like waste heat boilers, are not subject to the standards. Petitioners are correct that the EPA intended to exempt waste heat process heaters from the rule, and the EPA is amending the definition of process heater to exclude waste heat process heaters. We also are clarifying that waste heat boilers and process heaters can include supplemental burners as long as those burners combust only Gas 1 fuels, up to 50 percent of their heat input.”).]

Response: The EPA thanks the commenter for their support.

100A. Waste Heat Boiler and Process Heater

Commenter Name: Paul G. Page
Commenter Affiliation: AK Steel Corporation
Document Control Number: EPA-HQ-OAR-2002-0058-3457-A2
Comment Excerpt Number: 5

Comment: AK Steel supports EPA's efforts to exempt waste heat boilers from the Boiler MACT requirements, but believes that the Agency needs to broaden the definition of "waste heat boiler" to include process gases that otherwise would be flared. AISI and ACCCI have provided comments for EPA to accomplish that, including proposed new definitions. AK Steel fully supports those comments and recommends that EPA give them serious consideration as they will resolve potential complex exemption applicability determinations and compliance uncertainty.

Response: We thanks the commenter for their support to exempt waste heat boilers. The exemption has been revised to exempt all waste heat boilers which are actually heat exchangers generating heat from hot exhaust gases generated by other combustion units.

Commenter Name: Paul G. Page
Commenter Affiliation: AK Steel Corporation
Document Control Number: EPA-HQ-OAR-2002-0058-3457-A2
Comment Excerpt Number: 8

Comment: If the coke oven gas cannot be combusted as a supplemental fuel in the waste heat boilers, then the alternative is for AK Steel to flare the coke oven gas and to combust natural gas in the waste heat boilers. This alternative is not beneficial to anyone, and only serves to increase emissions to the environment.

Response: The definition of a waste heat boiler is a heat exchanger generating steam from hot off-gases (i.e., waste heat) from a combustion unit located at the facility. A waste heat boiler does not have its own combustion system. The rule has been revised to exempt all waste heat boilers because they are not part of the source category.

Commenter Name: Peter Pagano

Commenter Affiliation: American Iron and Steel Institute (AISI)

Document Control Number: EPA-HQ-OAR-2002-0058-3490-A1

Comment Excerpt Number: 1

Comment: As explained in AISI's Initial Comments on the original proposed rule, iron and steel manufacturing is an energy-intensive industry that extensively utilizes process gases and waste heat to offset fossil fuel consumption. The iron and steel industry can handle its process gases—notably blast furnace gas, coke oven gas, and basic oxygen furnace off gas—in one of two ways: either flare them or otherwise utilize them as fuels to meet environmental and safety requirements.

Utilizing process gases in a boiler or process heater is the environmentally preferred option for three reasons. First, controlling process gases in a boiler or process heater allows the recovery of energy that otherwise would be wasted. By capturing process gases, routing them to boilers and process heaters that require heat, and moving the point of combustion to those units, previously unused energy and wasted heat are put to work. Second, this practice helps reduce overall emissions in steel manufacturing facilities. When process gases are used as fuel in boilers and process heaters, they offset the use of fossil fuels in those units, thereby eliminating greenhouse gases, criteria pollutants, and HAP emissions associated with those fuels. Finally, process gases are more efficiently combusted in a boiler than when flared. Flaring is exposed to wind and other elements that may interfere with complete combustion. Supplemental fuel at a flare typically is limited to the pilot light and is not available to help ensure a stable flame, which further interferes with efficient combustion. As reflected in EPA's emission factors, flares are less efficient than boilers at controlling organic compounds.⁴ For these reasons, encouraging the iron and steel industry to control process gases by combusting them in boilers or process heaters is environmentally preferred to flaring them, which is the only other option.

[Footnote]

(4) See EPA, AP-42 at 1.403, 12.5-4 (citing EPA's Flare Efficiency study, EPA-600/2-83-052).

Response: We agree that there is an environmental benefit to combusting regulated gases in a boiler instead of flaring them. Thus, we have revised the definition of "gaseous fuel" in the final rule to clarify that regulated off gases are not included in the definition. Therefore, if a boiler combusted a combination of regulated off gases and natural gas, the boiler would be considered to be in the Gas 1 subcategory.

Commenter Name: Peter Pagano
Commenter Affiliation: American Iron and Steel Institute (AISI)
Document Control Number: EPA-HQ-OAR-2002-0058-3490-A1
Comment Excerpt Number: 3

Comment: The definitions of waste heat boiler and process heater should be amended so that units combusting process gases for control are exempt from the Boiler MACT.

The clearest way to effectuate these exemptions would be to revise the definitions of "waste heat boiler" and "waste heat process heater" to include process gases used in the iron and steel industry. To the extent that process gases either specifically already are exempt or otherwise regulated when combusted, utilizing them in a boiler or process heater should not result in increased regulation. We again propose that EPA amend the definitions of "waste heat boiler" and "waste heat process heater" to exempt process gas-fired units at iron and steel facilities from the Boiler MACT. This would be the most succinct amendment to effectuate the objective of efficient and environmentally preferable combustion of process gases in boilers and process heaters.

In the Proposed Rule, a "waste heat boiler" is defined as "a device that recovers normally unused energy and converts it to usable heat. Waste heat boilers are also referred to as heat recovery steam generators. This definition includes both fired and unfired waste heat boilers." The definition of "waste heat process heater" similarly "means an enclosed device that recovers normally unused energy and converts it to usable heat. Waste heat process heaters are also referred to as recuperative process heaters. This definition includes both fired and unfired waste heat process heaters." In the same way that EPA does not intend to regulate waste heat boilers or process heaters under the Boiler MACT, it also does not intend to regulate units controlling process gases in the iron and steel industry. By way of example, blast furnace gas-also a process gas recovered in the iron and steel industry-is exempt under the rule. We, therefore, propose that the definition of waste heat boiler and waste heat process heater be amended by adding the language in bold to the respective definitions:

Waste heat boiler means a device that recovers normally unused energy or process gas that otherwise would be flared and converts it to usable heat

Waste heat process heater means an enclosed device that recovers normally unused energy or process gas that would otherwise be flared and converts it to usable heat. ...

These changes, like previous alterations to these definitions, would reflect that EPA does not intend to regulate units combusting process gases.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3457-A2, excerpt 11 regarding the revision to the definition and exemption for waste heat boiler.

Commenter Name: Eric Guelker, Alliant Energy Corporate Services, Inc.
Commenter Affiliation: Interstate Power and Light Company (IPL) and Wisconsin Power and Light Company (WPL), Alliant Energy Corp.

Document Control Number: EPA-HQ-OAR-2002-0058-3492-A1

Comment Excerpt Number: 7

Comment: Whereas the MATS require that performance stack testing be conducted quarterly, this frequency is not warranted for smaller units regulated under this rule. Rather testing should be done as is currently required in Title V operating permits.

Response: Compliance testing to demonstrate compliance with the emission limits is generally required on an annual basis.

Commenter Name: Paul G. Page

Commenter Affiliation: AK Steel Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3457-A2

Comment Excerpt Number: 11

Comment: If EPA maintains the Boiler MACT provisions as they are currently proposed and if AK Steel decides to operate the waste heat boilers as they currently are, then the waste heat boilers would be subject to Gas 2 requirements. However, AK Steel doubts that compliance with the stipulated emission limits for Gas 2 sources would be achievable for these units. The standards presume emissions from only one source, but the waste heat boilers have emissions from the combustion of supplemental fuel from the boilers as well as fuel from the slab reheat furnaces, as the exhaust gases from both of these sources are discharged through the same exhaust stack. Since the two sources operate in tandem, EPA would need to establish a subcategory for waste heat boilers of this type to include the emissions from their source of waste heat if EPA is intent on regulating these sources as the rule is currently written. It would not be appropriate to conduct a stack test on the waste heat boiler without the slab reheat furnace operating because that would not be indicative of normal operations and, in that scenario, it would no longer be a waste heat boiler. Accordingly, AK Steel encourages EPA to give serious consideration to clarifying the exemption for waste heat boilers, preferably through the revision to the definition of "waste heat boiler" by including "process gas that otherwise would be flared" to provide optimal clarity.

Response: The exemption for waste heat boilers in the final rule has been revised to clarify that all waste heat boilers, whether with supplement firing or not, are exempt from the rule. Waste heat boilers are heat exchangers and do not meet the definition of "boiler" in the rule nor were considered part of the source category.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 137

Comment: The definitions of "waste heat boiler" and "waste heat process heater" should expressly include the use of waste heat from process gases that would otherwise be flared. Flares waste heat and energy and recovering that wasted heat and energy in a boiler or process heater adds no new emissions to the atmosphere. Boilers and process heaters tend to be more efficient and, therefore, produce less of the HAP emissions attributable to incomplete combustion than

would be produced at a flare. Also, using process gases displaces fossil fuels that would otherwise contribute additional emissions to the atmosphere and deplete limited energy resources. Waste heat boilers are exempt because they offer energy efficient use of otherwise wasted heat and energy – which is precisely what happens when the point of process gas combustion is moved from a flare to a boiler or process heater.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3490-A1, excerpt 1.

Commenter Name: Bruce A. Steiner

Commenter Affiliation: American Coke and Coal Chemical Institute (ACCCI)

Document Control Number: EPA-HQ-OAR-2002-0058-3547-A2

Comment Excerpt Number: 3

Comment: The current definitions of these terms evolved from considerations of what EPA intended not to regulate under the Boiler MACT. Initially, all units that combust solid waste were exempt. EPA then expanded the rule to cover boilers and process heaters that combust solid waste but are exempt, by statute, from section 129 incinerator rules because they are qualifying small power producers or cogeneration units that combust a homogenous waste stream. EPA intended the change to be in line with its goal to set emissions standards for all boilers and process heaters that are not solid waste incineration units subject to regulation under section 129. The proposed rule included a definition of waste heat boiler that excluded units with supplemental burners that are designed to supply 50 percent or more of the total rated heat input capacity. EPA subsequently removed the criteria that 50 percent of total rated heat input capacity had to be from waste gases to qualify as a “waste heat boiler” and revised the final definition to include all waste heat boilers.

Based on these considerations, a “waste heat boiler” is defined as “a device that recovers normally unused energy and converts it to usable heat. Waste heat boilers are also referred to as heat recovery steam generators. This definition includes both fired and unfired waste heat boilers.” “Waste heat process heater” is similarly defined and are also referred to as recuperative process heaters.

In the same way that EPA did not intend to regulate waste heat boilers or process heaters under the Boiler MACT, it also did not intend to regulate units controlling process gases in the steel and coke industry. We, therefore, propose that the definition of waste heat boiler and waste heat process heater be amended by adding the following language in bold to the respective definitions:

Waste heat boiler means a device that recovers normally unused energy or process gas that otherwise would be flared and converts it to usable heat. . . .

Waste heat process heater means an enclosed device that recovers normally unused energy or process gas that would otherwise be flared and converts it to usable heat. . . .

These changes, like previous alterations to these definitions, would reflect that EPA does not intend to regulate units combusting process gases.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3490-A1, excerpt 1.

2C. Exempted NESHAP Control Devices

Commenter Name: Paul G. Page

Commenter Affiliation: AK Steel Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3457-A2

Comment Excerpt Number: 9

Comment: EPA has indicated that it does not intend to regulate further boilers and process heaters that combust process gases, which are regulated under 40 C.F.R. Parts 60, 61, and 63. Since the combustion of coke oven gas is regulated by another NESHAP (40 C.F.R. 63.307, Subpart L), AK Steel believes that EPA's intention is to exempt the combustion of coke oven gas-fired boilers and process heaters under this exemption provision. AK Steel supports that approach. However, AK Steel contends that the qualification for the exemption which EPA has proposed should be revised.

The exemption qualification criteria in the proposed Reconsideration Rule specifies that at least 50 percent of the heat input to the boiler must be provided by a "regulated gas stream." In other words, the majority of the gas stream, or fuel as combusted, must be regulated by Parts 60, 61, or 63 to be exempt from the Boiler MACT. Although all coke oven gas sent to a boiler or process heater from a coke oven gas recovery plant is "regulated," other process gases (regulated or not) as well as natural gas may also comprise the boiler's gas stream and potentially "dilute" the ratio of "regulated" to "unregulated" gas sufficiently to negate this exemption or maintain it so close to the 50% threshold as to cause uncertainty.

AK Steel's facility with the four waste heat boilers, as described above, provides a direct example of the need to revise these exemption criteria. The total volume of coke oven gas is being diverted to 4 "control devices" (waste heat boilers) instead of one flare. The coke oven gas is blended with diluted natural gas prior to combustion, with additional natural gas used as needed for increased boiler demand. The ratio of coke oven gas to natural gas usage by volume per waste heat boiler oscillates around 50% for each fuel. This creates unacceptable regulatory uncertainty.

However, the critical point is that the total coke oven gas volume is combusted in a "control device" which is more efficient than the flare and, subsequently provides improved environmental benefit. It should not make any difference whether the total volume of regulated gas is combusted in four control devices or one. In addition, it should not make any difference whether the regulated gas is combusted in a fuel blend at a ratio less than or greater than 50% since all of the coke oven gas is being combusted. Accordingly, compliance with the intent of the exemption is being achieved since all of the regulated gas, coke oven gas in this case, is being combusted, which is the requirement of the Subpart L standard at 40 C.F.R. § 63.307.

The fact that a gas stream, as combusted, going to a boiler or process heater may contain less than 50% of a specific regulated gas should not be the deciding factor for these exemption criteria. The 50% threshold serves no useful purpose and may provide an unintended consequence of determining whether it is more cost-effective for AK Steel to flare coke oven gas and burn natural gas in our waste heat boilers.

Response: The exemption listed in 63.7491(i) is for a boiler, or process heater, that is used as a control device. Waste heat boilers are not by definition, in the final rule, a "boiler" because waste heat boilers are not enclosed devices using fuel combustion. Waste heat boilers, or heat recovery steam generators (HRSG), are heat exchangers generating steam from the incoming hot exhaust gas from industrial (e.g., thermal oxidizers, kilns, furnaces) or power (e.g., combustion turbine, engine) equipment. Duct burners, which are mounted in a duct or discharging into a duct, are sometimes used to increase the temperature of the hot exhaust gas from a combustion turbine to increase steam production in a HRSG to increase electricity output from a combined cycle gas turbine system.

Coke oven gas that is required to be controlled by another NESHAP or NSPS and is controlled by flaring or by a thermal oxidizer (e.g., afterburners) and then the hot off gas is routed to a waste heat boiler would not be subject to the rule. Coke oven gas that is required to be controlled and routed to a boiler or process heater for control is, in the final rule, an exempted gas. In the final rule, the definition of gaseous fuel has been revised to clarify that off gases regulated by another standard under parts 60, 61, 63, or 65 are exempt from this definition. However, a boiler combusting these regulated off gases is only exempted if the regulated off gases account for at least 50% of the heat input to the boiler. If less than 50%, the boiler is subject to the rule and is in the subcategory based on the fuel being combusted with the regulated off gases.

The 50% criteria for the exemption has been clarified in the final rule to be 50% of the average annual heat input during any 3 consecutive calendar years. To clarify, if 50 percent of the fuel is not regulated by another standard, the combustion unit is subject to the Boiler MACT.

Commenter Name: Paul G. Page

Commenter Affiliation: AK Steel Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3457-A2

Comment Excerpt Number: 10

Comment: AK Steel contends that the exemption qualification criteria should be that all of the regulated process gas be combusted in a "control device" at least as efficient as a flare, independent of its concentration as combusted. The fuel ratios established for our combustion units are done-so to enhance efficiency which in turn reduces emissions. Therefore, AK Steel respectfully suggests that EPA revise this exemption by adding language to it which would stipulate that boilers and process heaters (including waste heat boilers and process heaters unless they are exempted elsewhere) that combust a gas stream which includes coke oven gas that is regulated under Part 61, is therefore exempt from the Boiler MACT requirements.

Response: We disagree with the comment to exempt any boiler or process heater combusting any amount of coke oven gas from the rule. See the response to comment EPA-HQ-OAR-2002-0058-3457-A2, excerpt 9 regarding revisions being made to the final rule to clarify this exemption.

Commenter Name: Peter Pagano

Commenter Affiliation: American Iron and Steel Institute (AISI)

Document Control Number: EPA-HQ-OAR-2002-0058-3490-A1

Comment Excerpt Number: 6

Comment: AISI requests express clarification in the rule or preamble that a coke oven gas-fired boiler is a control device pursuant to one or more of these parts and that coke oven gas is a "gas stream that is regulated under Mother subpart" as that phrase is used in the above exemption. Indeed, coke oven gas is regulated in a number of different subparts. For example, coke oven emissions vented through a bypass/bleeder stack must be flared or vented to an alternative control device. See 40 C.F.R. 63.307, Subpart L. Subpart L also limits leaks from offtake systems and collecting mains, which collect coke oven gas from the ovens.

Coke oven gases are processed in a byproduct recovery plant, after which generally about 40 percent is used to underfire the coke ovens and the remainder is available for use as a fuel elsewhere in the plant. See Subpart L of Part 61 (40 C.F .R. 61.130-61.139) regulates benzene emissions from coke oven gas processing systems in a byproducts recovery plant. Under art 61, Subpart L, all process vessels, which must be enclosed and whose openings must be sealed, vent the coke oven gas to a collection and distribution system where the benzene in the gas must be recovered or destroyed.¹⁷

Some iron and steel facilities, however, recover benzene in their byproducts plant before they send coke oven gas to a boiler or flare. In these instances, Part 61 may not regulate the clean coke oven gas leaving the byproducts plant. Nonetheless, this clean coke oven gas is sent to a boiler or process heater for beneficial reuse; or, alternatively, sent to a flare for combustion before it is released to the atmosphere. Although Subpart L requires a properly operated flare or an alternate system (approved by the Administrator) that achieves 98% destruction of the coke oven gas vented to the system, it is not clear whether a boiler combusting this clean coke oven gas would be considered a "control device" used to comply with Subpart L since the combustion, in these instances, occurs on clean coke oven gas. Since all boilers achieve 98% combustion efficiency when properly maintained and operated, EPA may use the Reconsidered Rule to impose an annual tune-up obligation as the sole requirement and approve the boiler as an alternate system under 40 C.F.R. § 63.307, which would clearly subject the coke oven gas-fired boiler to the MACT standard in Part 61, Subpart L. Here is an instance where "dirty" coke oven gas is exempt because it is subject to Subpart L, but "clean" coke oven gas may not be exempt. To address this potential gray area, AISI asks that EPA add a sentence to the exemption to also expressly exclude clean coke oven gas-fired boilers and process heaters.

[Footnote]

(17) 40 C.F.R. § 61.132(a)(2).

Response: See the response to comment EPA-HQ-OAR-2002-0058-3457-A2, excerpt 9. The final rule has been revised to exempt off-gases that are regulated under another part 63 standard. Therefore, a boiler, or process heater, that combust regulated off-gases would be classified in a subcategory based on the fuel combusted in combination with the regulated off-gas. For example, if the regulated off-gas was combusted in combination with national gas, the unit would be in the Gas 1 subcategory, If the off-gas is combusted in combination with coal, the unit would be in one of the coal subcategories.

Commenter Name: Peter Pagano
Commenter Affiliation: American Iron and Steel Institute (AISI)
Document Control Number: EPA-HQ-OAR-2002-0058-3490-A1
Comment Excerpt Number: 7

Comment: AISI also seeks clarification regarding how this exemption is applied to mixed gas streams. Currently, the proposed exemptions in the Reconsidered Rule depend on whether at least 50 percent of the heat input to the boiler is provided by a "regulated gas stream." This means that the majority of a gas stream must be regulated by Parts 60, 61, or 63 to be exempt from the Boiler MACT. Even if all coke oven gas sent to a boiler or process heater from a coke byproduct plant is considered "regulated," other gases that are not regulated may be mixed into the fuel gas system that may "dilute" the ratio of "regulated" to "unregulated" gas sufficiently to negate the exemption. For instance, blast furnace gas often is mixed with coke oven gas at integrated iron and steel mills when process gases are combusted in a boiler. Blast furnace gas is excluded from the Boiler MACT definition of gaseous fuel because of its low HAP content. When blast furnace gas is unavailable, natural gas may be used to supplement the fuel source. Ironically, if more than 50 percent of the heat input for a control device was from blast furnace gas and/or natural gas, the coke oven gas-fired boiler could lose its exemption. This is an unnecessary limitation of the exemption.

AISI, therefore, requests that EPA amend the proposed exemption to allow for all process gases (otherwise regulated or not) to count towards the 50 percent applicability threshold. The fact that a gas stream going to a boiler or process heater may contain less than 50% of a specific regulated gas does not diminish the environmental benefit of encouraging the use of process gases. The 50% threshold serves no useful purpose and may provide an unintended consequence that harms rather than benefits the environment.¹⁸

[Footnote]

(18) The threshold percentages for qualifying for exemptions throughout the rule (*e.g.*, as an otherwise regulated unit under parts 60, 61, or 63; as a blast furnace gas fuel-fired unit; or as a gas 1 unit) raise multiple compliance issues. The Reconsidered Rule does not explain how an operator can demonstrate compliance with an exemption or the rule when its unit may be exempt at one point in time because it meets a percentage threshold, but later no longer qualifies under that exemption. This would cause units to be covered intermittently by the Boiler MACT. We urge EPA to clarify how it intends to deal with these compliance issues. We propose that EPA exclude both blast furnace gas and natural gas from the calculation if the boiler meets the gas I tune-up requirement. *See also supra*, at 8 (discussing "compliance conundrum").

Response: See the response to comment EPA-HQ-OAR-2002-0058-3457-A2, excerpt 9. We agree that the 50% criteria in the exemption needs clarification. We have revised the exemption criteria to allow all regulated and exempted process gases to count towards 50%.

Commenter Name: Dan F. Hunter
Commenter Affiliation: ConocoPhillips Company
Document Control Number: EPA-HQ-OAR-2002-0058-3689-A2
Comment Excerpt Number: 3

Comment: ConocoPhillips agrees with an exemption for BPH used as a control device to comply with another subpart. However, the 50% threshold is arbitrary and should be removed as a criterion within the exemption. This exemption should apply to any BPH used as a control device to comply with another subpart regardless of the percent heat input. There are at least two reasons for this:

1. In the BPH as a control device exemption, EPA does not specify an averaging time (e.g., 50% heat input on an annual basis) so the safe course for facilities that might be close to that 50% threshold will be to assume that any excursions below 50% heat input will disqualify one from the exemption. This, of course, causes the installation of more fuel burning equipment (e.g., thermal oxidizer).

2. Consider a BPH used as a control device in tank loading, subject to the Organic Liquid Distribution MACT. In this scenario, the BPH receives gases pushed out of the tank(s) and burns them in the course of electrical power generation. Initially, the gases recovered and routed to the BPH represent more than 50% of the total BPH heat input. But over time, the facility throughput will vary. Market forces and natural production declines will cause this variation. So there will be periods, possibly very extended, when throughput is insufficient to generate enough gas to be more than 50% of the heat input necessary for facility power generation. Similarly, after periods of extended decline, market upswings or whatever else might increase throughput could push the heat input back above 50%. So could a facility's exemption status vary from year to year? We do not believe this is intended nor do we believe this is a sound regulatory approach.

This is an issue with the exemption rooted in a real situation that heat input averaging periods will not solve. The periods of variability could last years. In addition, establishing another heat input threshold, say 20 or 80%, will also not solve the issue. The correct solution must be to eliminate the heat input threshold altogether thereby encouraging the continued use of the BPH as a control device. Otherwise, it is inescapable that additional fuel burning unit(s) will be installed.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3457-A2, excerpt 9. The 50% criterion has been clarified in the final rule. To clarify, the exemption can vary from year to year if the average annual heat input during any 3 consecutive calendar years from the regulated off-gas drops below 50%.

Commenter Name: Peter Pagano

Commenter Affiliation: American Iron and Steel Institute (AISI)

Document Control Number: EPA-HQ-OAR-2002-0058-3490-A1

Comment Excerpt Number: 5

Comment: The exemptions for boilers and process heaters used as devices to comply with standards issued under 40 C.F.R. Parts 60, 61, or 63 should be expanded to include all process gases.

EPA has indicated that it does not intend to regulate further boilers and process heaters that are fed by process gases otherwise regulated under 40 C.F.R. Parts 60, 61, and 63. AISI supports EPA's approach but believes that further clarification and expansion of the proposed exemption is needed to avoid creating conflicts with existing regulatory obligations and imposing

disincentives to the efficient combustion of all process gases. The expanded exemptions are necessary to encourage iron and steel manufacturers to send process gases to boilers instead of to less efficient flares. Sources would be dissuaded from combusting process gases in boilers if those sources had to comply with the Boiler MACT.¹⁵

The Reconsidered Rule appropriately would exempt from the Boiler MACT, "Any boiler or process heater that is used as a control device to comply with another subpart of this part [(part 63)], or part 60, or part 61 of this chapter provided that at least 50 percent of the heat input to the boiler or process heater is provided by the gas stream that is regulated under another subpart." Part 60 sets new source performance standards ("NSPS") for new or modified stationary sources, including new boilers, and controls organic pollutants, and Parts 61 and 63 set national emission standards for hazardous air pollutants ("NESHAP"). AISI supports EPA's proposal to exclude from the Boiler MACT those boilers and process heaters that serve as control devices under one of these parts. The exclusion specifically would address AISI's concern that process gases that must be flared are not subject to additional costs of control when they are combusted in a boiler or process heater. The proposed language in the exemption, however, must be expanded to address the process gases generated by the iron and steel industry.

[Footnote]

(15) Initial Comments, 6-7.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3457-A2, excerpt 9.

Commenter Name: Bruce A. Steiner

Commenter Affiliation: American Coke and Coal Chemical Institute (ACCCI)

Document Control Number: EPA-HQ-OAR-2002-0058-3547-A2

Comment Excerpt Number: 1

Comment: Boilers and Process Heaters Using Coke Oven Gas Should Be Exempt from the Boiler MACT

EPA has indicated that it does not intend to regulate further boilers and process heaters that are fed by process gases otherwise regulated under 40 CFR Parts 60, 61, and 63.⁴ ACCCI supports EPA's approach but believes that further clarification and expansion of the proposed exemption is needed to avoid conflicts with existing regulatory obligations and imposing disincentives to the efficient combustion of all process gases. The proposed exemptions are necessary to encourage coke manufacturers to send coke oven gas to boilers instead of to less efficient flares. Sources would be dissuaded from combusting process gases in boilers if those sources had to comply with the Boiler MACT.

The Reconsidered Rule appropriately would exempt from the rule boilers and process heaters used as controls to comply with Parts 60, 61, and 63. Pollutants controlled under any of these parts are more efficiently controlled in a boiler than a flare. For example, coke oven gas combustion currently is regulated by another NESHAP (40 CFR 63.307, Subpart L). Coke oven gases are processed in a byproduct recovery plant, after which about 40 percent is used to underfire the coke ovens and the remainder is available for use as a fuel elsewhere in the plant. Subpart L of Part 61 (40 C.F.R. 61.130- 61.139) regulates benzene emissions from coke

byproduct recovery plants. Under Subpart L, process coke oven gas may be sent to an enclosed combustion device (e.g., boiler) in a closed-vent system or sent to flare, if proper controls are achieved. The overall control system in the byproduct plant must be designed and operated for no detectable emissions, as indicated by a benzene instrument reading of less than 500 ppm above background and visual inspections.⁵ Any fugitive gases from the system must be captured and sent to a control device.⁶ If a boiler is used as a control device for Subpart L purposes, it must be designed and operated to reduce volatile HAP emissions vented to it with an efficiency of 95 percent or greater or to specified levels.

[Footnote]

(4)76 Fed. Reg. at 80,615-16, 80,628.

(5) 40 C.F.R. § 61.132.

(6) Id. § 61.135.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3457, excerpt 9.

Commenter Name: Bruce A. Steiner

Commenter Affiliation: American Coke and Coal Chemical Institute (ACCCI)

Document Control Number: EPA-HQ-OAR-2002-0058-3547-A2

Comment Excerpt Number: 2

Comment: Utilization of process gases in boilers is a superior control option to flaring under existing regulations. As explained above, elements causing unstable flames reduce a flare's efficiency relative to a boiler. As reflected in EPA's emission factors, flares are less efficient than boilers for controlling organic compounds. Boilers therefore are a means of reducing organic pollutant emissions to a much greater degree than what a flare would emit. EPA recognizes that the Boiler MACT unnecessarily would overlap with these regulations, and potentially dissuade facilities from sending process gases and waste heat to boilers and instead encourage flaring. Flaring also results in the loss of valuable energy. By capturing process gases and moving their point of combustion to a boiler, previously unused energy is converted to usable heat. At coke plants operated by integrated iron and steel producers and at stand-alone coke plants, approximately 60 percent of off gases from coke ovens are recovered and combusted for their waste heat in a boiler or process heater. Process gases thus are used as an alternative fuel, reducing the need to burn fossil fuels and further curtailing overall emissions. EPA, therefore, correctly encourages the continued use of combustion controls by exempting boilers and process heaters that comply with Parts 60, 61 or 63.⁷

ACCCI strongly supports these exemptions, but believes that certain clarifications are needed and that the exemptions should be expanded to cover boilers and process heaters fired by coke oven process gases, which are regulated under Parts 60, 61 and/or 63. Currently, the proposed exemptions in the Reconsidered Rule depend on whether at least 50 percent of the heat input to the boiler is provided by a "regulated gas stream." This means that the majority of a gas stream must be regulated by Parts 60, 61, or 63 to be exempt from the Boiler MACT. Although all coke oven gas sent to a boiler or process heater from a coke byproduct plant is "regulated," other process gases (regulated or not) may also comprise the boiler's gas stream and potentially "dilute" the ratio of "regulated" to "unregulated" gas sufficiently to negate the exemption. If

sending coke oven gas to a boiler would subject the source to the Boiler MACT, the industry's practical response instead would be to flare the gas. ACCCI, therefore, requests that EPA amend the proposed exemption to allow for all process gases (otherwise regulated or not) to count towards the 50 percent applicability threshold. The fact that a gas stream going to a boiler or process heater may contain less than 50% of a specific regulated gas does not diminish the environmental benefit of encouraging the use of process gases. The 50% threshold serves no useful purpose and may provide an unintended consequence that harms rather than benefits the environment.

Response: We agree that utilization of process gases in boilers is a superior control option to flaring. See the response to comment EPA-HQ-OAR-2002-0058-3457-A2, excerpt 9.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 16

Comment: We support EPA's proposal to exempt BPH used as control devices for VOC, provided that at least 50% of the heat duty for the unit is derived from regulated streams, but request revisions to §63.7491(i) and the definitions of boiler and process heater to clarify this exemption.

1. As EPA concludes, recovery of energy from gas streams combusted for compliance with regulations reduces overall emissions versus having to provide those energy needs from fuel combustion and thus should be encouraged. This obvious and significant pollution prevention position is independent of whether the combustion is of HAP, VOC or, as is typical, both. Thus, EPA is correct in including streams regulated under part 60, as well as parts 61 and 63 in the exemption. However, some combustion control requirements are set in part 65 subparts B through G (the SOCOMI Consolidated Air Rule) and EPA is currently working to transfer many other combustion control requirements from parts 60, 61 and 63 to part 65 through the Uniform Standards effort (part 65 subparts H through M). Although applicability of the control requirements will still be maintained in parts 60, 61 and 63, we recommend including part 65 in the exemption language to avoid future confusion over whether the exemption applies or not when the combustion control is specified in part 65, rather than parts 60, 61, or 63.

2. Proposed §63.7491(i) defines which BPH are being exempted as follows.

(i) Any boiler or process heater that is used as a control device to comply with another subpart of this part, or part 60 or part 61 of this chapter provided that at least 50 percent of the heat input to the boiler or process heater is provided by the gas stream that is regulated under another subpart.

Proposed §63.7491(i) needs to be clarified to be clear how the 50% heat input requirement is applied. We see three issues with this wording that need clarification. First, it needs to be clear that the heat input from all regulated streams is summed for the 50% test. Second, it should be made clear that the heat duty for a regulated stream is based on its total heat content, not just the heat content of the regulated species (i.e., for a part 63 regulated streams it is not just the HAP heat duty that counts, for a part 60 stream it is not just the VOC heat duty that counts). Finally, it

should be clarified that the 50% test is on an calendar annual average basis, since there will be times (e.g., normal stream variability or when a unit producing a regulated stream is out-of-service for maintenance) when the 50% criteria is not met on an instantaneous or even daily basis.

3. To address these concerns (1 and 2 above) we suggest the following revisions to the proposed §63.7491(i) language.

(i) Any boiler or process heater that is used as a control device to comply with another subpart of this part, or part 60 or part 61 or part 65 of this chapter provided that at least 50 percent of the heat input to the boiler or process heater, as a calendar annual average, is provided by the gas streams that areis regulated under another subparts. For gas streams regulated under other subparts, the entire heat input of the streams are summed when determining their heat input contribution, not just the heat input from the regulated species in the streams.

Response: The EPA thanks the commenter for their support. We agree that clarification of the exemption is needed and have revised the exemption in the final rule similar to that suggested by the commenter to include part 65.

Commenter Name: Mark Anthony

Commenter Affiliation: Alyeska Pipeline Service Company

Document Control Number: EPA-HQ-OAR-2002-0058-3684-A2

Comment Excerpt Number: 4

Comment: Alyeska supports determining the heat input on an annual average basis that is a further described as a rolling 12-consecutive month period. First, this approach is consistent with how annual averages are used in most EPA and state programs. For example, the Terminal's existing permit requirements to meet state SIP permit limits are based on this approach. Second, this approach seems logical because it provides for seasonal variability or other short term circumstances when regulated gas streams may be limited or the heat content of the gas changes. However, on an annual average the gas streams do contribute more than 50% of the heat input to the boilers. Since Alyeska believes it is EPA's intent to promote the usage of on-site gas over other off-site fuels, such as liquid or solid fuels, which result in additional emissions, an annual basis would be beneficial and would not penalize a facility during the short periods the 50 . percent criteria couldn't be met.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3457-A2, excerpt 9 for clarifications on 50% heat input.

Commenter Name: Mark Anthony

Commenter Affiliation: Alyeska Pipeline Service Company

Document Control Number: EPA-HQ-OAR-2002-0058-3684-A2

Comment Excerpt Number: 3

Comment: We are uncertain about how the exemption may practicably terminate for a boiler that is utilizing this exemption. If a boiler has been operating under the exemption at § 63.7491 (i) by burning over 50 percent gaseous fuel on a heat input basis from regulated gas streams and

the regulated gas stream drops below 50% on an annual average (see comment below) how soon would the boiler have to meet the emission standards of the rule? Depending upon circumstances, a drop in the regulated gas stream heat input usage may not be foreseeable or avoidable. Gas streams that arise from processes may appear to be forecastable, but unforeseeable economic conditions or other events may change the supply of the underlying commodity that generates the gas stream. This in turn may result in a rapid unforeseeable diminishment in the gas stream volume and corresponding heat input to the boiler. If a facility has to retrofit boilers with emission controls sufficient time must be allowed to reasonably allow for the changes to be made. Therefore, Alyeska proposes that EPA clarify this obligation and provide a reasonable time for installation of controls to the boilers. Based upon our review of the timeframe to make such a change at least three years will be needed after a boiler no longer qualifies for the exemption criteria to put in place the controls, monitoring and other requirements necessary to meet the rule's compliance obligations.⁴

[Footnote]

(4) We supported 5 years for the initial compliance period for Boiler MACT, but recognize that later in the life of a boiler that a 3 year timeframe may be achievable if transitioning from the control device exemption to full Boiler MACT compliance, including the addition of controls. There will be considerable national experience developed by contractors to install controls and companies that utilize the exemption will have some anticipation and understanding of what Boiler MACT compliance looks like at these later dates.

Response: The commenter raises an interesting concern regarding the exemptions in 63.7491. 63.7495 (When do I have to comply with this subpart?) does not address the situation when an exempted boiler or process heater changes the manner of operation such that the unit is no longer exempt. 63.7495(c)(2) states that "Any existing boiler or process heater at the existing source must be in compliance with this subpart within 3 years after the source becomes a major source." We have revised 63.7495 to add a similar compliance time for units that change such that they are no longer exempted under 63.7491(i).

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 119

Comment: ACC supports the proposed exemption from applicability to this rule in § 63.7491(h) for those boilers and process heaters that are specifically listed as an affected source in another standard under 40 CFR Part 60, 61, or 63. There are several existing NESHAPs that include boilers and process heaters within the scope of the affected source through different language. Some of the NESHAPs that include boilers and process heaters within the definition of "affected source" when used as a control device are Subparts JJJ, OOO, PPP, U. ACC requests that EPA provide specific identification of all applicable NESHAPs wherein boilers and process heaters used as control devices under those subparts are considered part of that affected source and thereby not subject to Subpart DDDDD. Having EPA provide this specificity will avoid confusion and minimize permitting time and effort associated with applicability determinations.

Response: We agree that providing specific identification of all applicable NESHAPs wherein boilers and process heaters used as control devices under those subparts are considered part of that affected source and thereby not subject to Subpart DDDDD will avoid confusion and minimize permitting time and effort associated with applicability determinations. We also agree that boilers and process heaters that are used as a method of compliance, used as a control device, in Subparts JJJ, OOO, PPP, U. are within the definition of affected source for those subparts. The exemption in 63.7491(h) has been revised in the final rule to specifically list these subparts.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 120

Comment: Similarly, gases that are combusted in a boiler or process heater used as a control device for any NESHAP should be specifically excluded from the definition of other gases (Gas 2). Combustion devices should not be subject to multiple NESHAP, and use as a control device should be considered the primary purpose for combustion of Gas 2 streams in this case.

EPA could specifically revise proposed § 63.7491(h) to include the combustion units, combustion unit exhaust streams, and process vent gas streams covered under another MACT as follows: *§63.7491(h) Any boiler, process heater, combustion unit, combustion unit exhaust stream, or process vent gas stream that is specifically listed as an affected source in another standard(s) under 40 CFR part 63.*

These process gas streams should also be exempt from the fuel sampling requirements, particularly gases that do not contain metals.

Response: We agree that exhaust streams should not be subject to multiple NESHAPs. The definition of "Gaseous fuels" in the final rule has been revised to indicate that off-gases regulated by another standard are excluded from the definition. Therefore, these regulated off-gases would be exempt from the fuel sampling requirement. Boilers and process heaters burning these regulated off-gases would be subject to the rule based on the type of fuel being combusted in combination with the regulated off-gases, unless the regulated off-gases account for more than 50% of the heat input to the boiler or process heater.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 17

Comment: Additionally, we request EPA discuss in the preamble or at least the response to comments the meaning of the term "provided by gas streams that are regulated under another subpart." Our understanding is that this term means that where the control of a gas stream is required under another subpart (e.g., Marine Vessel Loading NESHAP, RMACT 1, NSPS Kb or

GGGa, part 61 subpart FF), and that stream is routed to a boiler or process heater for the purpose of achieving the required control, then it is a regulated stream as that term is used here.

Response: We agree that clarification is needed. A definition of "Regulated gas stream" has been added to the final rule.

Commenter Name: Mark Anthony

Commenter Affiliation: Alyeska Pipeline Service Company

Document Control Number: EPA-HQ-OAR-2002-0058-3684-A2

Comment Excerpt Number: 2

Comment: Along with API and its members Alyeska thanks EPA for modifying the exemption to cover regulated gas streams under Parts 60 and 61. We also support API's additional requests for changes to help clarify the exemption.

Like all facilities that have regulated gas streams that are combusted as fuel in boilers subject to this standard it is very important that we clearly understand the application of this exemption. API's comments and requests for clarifying changes will do that. In addition, Alyeska asks EPA to provide some discussion in the preamble to the final rule or in the response to comments to provide further certainty about this exemption. Our concern is that the current record on this exemption is sparse as to how it might actually apply at specific facilities. Currently the only example, and it is a complex one, is the Norbord Industries comment and EPA's **Response:**

Norbord stated: "Many facilities exhaust process gases from other sources through the combustion chamber of a boiler or process heater. Does the standard apply to all or a portion of the exhaust? At one Norbord facility a portion of the process gases passing through the combustion unit is PCWP MACT regulated, and another portion of the gases passing through is from a kiln. Additionally, greater than 50% of the heat input to the boiler/process heater is from the kiln and dryers. At the very least wouldn't the boiler/process heater be considered a waste heat boiler?"

EPA responded as follows:

"EPA has modified the exemption to remove the phrase 'specifically listed' and replaced with 'part of the affected source' in order to address the concerns of the commenter. Further we added another exemption to allow for situations where the boiler serves as the control device for another MACT-regulated process where at least 50% of the heat input comes from the regulated process."

We realize there are statements by EPA in the preamble to the proposed rule reinforcing the benefit of the exemption. 76 FR 80615~ 80616. However, what is less certain is how the exemption will effectively apply. For example, at the Valdez Marine Terminal vapors are collected and controlled as described above under 40 CFR 63 Subparts Y and EEEE. Our understanding is that these collected vapors are a regulated gas stream for purposes of the exemption. Further, the collected vapors are used as fuel in the boilers, and meet the definition of a "gaseous fuel" under § 63.7575. The exemption also requires that the boiler perform as a control device to comply with another subpart. Subpart Y's emissions standard requires that a vapor collection system connect to an air pollution control device. Air pollution control device

for purposes of Subpart Y expressly includes boilers. Boilers are used at the VMT as control devices. Under Subpart Y, large boilers above a certain size are not required to satisfy emissions testing, monitoring and performance criteria that the thermal oxidizers must meet. EPA made that decision in the Subpart Y rulemaking because of the inherent combustion efficiency of boilers and the pollution prevention benefits of burning vapors for fuel in lieu of diesel or other fuels in the boilers. That is well documented in the rulemaking history. As you know EPA established this practice with the HON and it has properly been added to many MACT standards. It is our understanding that the VMT boilers when used in this manner are used as a control device to comply with another subpart and therefore satisfy this requirement of the control device exemption.

We believe the same is true for OLD MACT (Subpart EEEE) at the VMT. Subpart EEEE, requires regulated vapors to be collected and routed to either to 1) a dedicated air pollution control device, or 2) a fuel gas system followed by a combustion device. At the VMT, the dedicated control devices are thermal oxidizers; the combustion devices receiving regulated vapors via the fuel gas system are boilers (serving as control devices).

We would appreciate some discussion by EPA to confirm our understanding of the scope of this exemption to circumstances like ours where boilers receiving regulated gases via a vapor collection system and/or fuel gas system serve as control devices.

Response: We agree that clarification is needed. See the response to comment EPA-HQ-2002-0058-3510-A1, excerpt 120.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 59

Comment: EPA recognizes that Boiler MACT affected sources are utilized to combust process off-gases required by other subparts of 40 CFR Part 63 and has included language in §63.7510(a)(2)(ii) and in §63.7521(f)(2) to exempt these process off-gases from the periodic fuel analysis requirements and Gas 1 fuel specification requirements.

CIBO agrees with EPA's determination on these process gases. CIBO also agrees with EPA's determination that fuel analysis for chloride is not required for gases and that operators are not required to conduct the mercury fuel specification analyses for gaseous fuels that are natural gas, refinery gas, or otherwise subject to another subpart of part 63.

However EPA should extend the exemptions for not conducting fuel specification analysis and periodic fuel analysis to process gases that are regulated under Parts 60 and 61. Specifically, §63.7510(a)(2)(ii) and §63.7521(f)(2) should be amended with the addition of the bold language to read as follows:

§63.7510(a)(2)(ii) When natural gas, refinery gas, other gas 1 fuels are co-fired with other fuels, you are not required to conduct a fuel analysis of those fuels according to § 63.7521 and Table 6 to this subpart. If gaseous fuels other than natural gas, refinery gas, or other gas 1 fuels are cofired with other fuels and those gaseous fuels are subject to another subpart of this part, **to**

part 60, or to part 61 you are not required to conduct a fuel analysis of those fuels according to § 63.7521 and Table 6 to this subpart.

§63.7521(f)(2) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for gaseous fuels that are subject to another subpart of this part, **to part 60, or to part 61.**"

EPA has already extended the exemption to boilers and process heaters serving as control devices for controlling gaseous streams subject to Part 60 or Part 61 as noted in §63.7491(i).

Response: We agree and 63.7521(f)(2) in the final rule has been revised.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 160

Comment: Proposed §63.7545(f) imposes a reporting requirement associated with units that are designed to burn "gaseous fuel subject to another subpart of this part." As we have commented elsewhere, gaseous fuels subject to parts 60, 61 and 65 subparts should also be exempted from rule requirements along with gaseous fuels subject to part 63 subparts, thus we believe this phrase in §63.7545(f) should be revised to "gaseous fuel subject to another subpart of this part or a subpart of part 60, 61 or 65."

Response: We agree and 63.7545(f) has been revised in the final rule to be consistent with other revisions being made to address the issue of regulated off-gases.

Commenter Name: Timothy Serie

Commenter Affiliation: American Coatings Association (ACA)

Document Control Number: EPA-HQ-OAR-2002-0058-3502-A1

Comment Excerpt Number: 11

Comment: ACA generally supports the following proposed changes in the Boiler MACT rule:

Exemption for any boiler or process heater that is used as a control device to comply with standards issued under part 60, part 61, or part 63 of the CAA (provided that at least 50% of the heat input to the boiler is provided by a gas stream that is subject to the standards under those parts)

Response: The EPA thanks the commenter for their support.

Commenter Name: Shannon S. Broome

Commenter Affiliation: Auto Industry Forum (AIF)

Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1

Comment Excerpt Number: 52

Comment: EPA Should Finalize the Proposed Extension of the Exemption to Parts 60 and 61.

EPA proposes exempt from the Boiler MACT those units that facilities use as control devices to comply with the standards of part 60, part 61 or part 63 of the CAA, provided that "at least 50 percent of the heat input to the boiler is provided by the gas stream that is regulated under another subpart." *Boiler MACT Reconsideration Proposal*, 76 Fed. Reg. at 80,615-16. In the final rule, EPA had merely promulgated this exemption in the part 63 context, however, it now proposes to extend the exemption to parts 60 and 61 because of their respective relevance to the NESHAP program. *See id.* EPA, therefore, proposes to revise accordingly the provision at § 63.7491(i) that enumerates the boilers and process heaters not subject to the Boiler MACT. *See id.* at 80,628.

AIF supports extending the exemption to cover units required by parts 60 and 61 in addition to part 63 of the CAA and to units used as integral to control devices. Consider, for example, boilers used as part of VOC control devices for the purpose of desorbing the VOC that is adsorbed onto a carbon bed or wheel, such that the VOC can be concentrated and routed to a thermal oxidizer. Without the use of the boiler, this VOC control system would be extremely inefficient and require much larger thermal oxidizers and waste more NG in the destruction of VOC. Therefore, EPA should finalize its proposed amendment to the exemption for units serving as control devices.

Response: The EPA thanks the commenter for their support.

Commenter Name: Vickie Woods

Commenter Affiliation: Division of Air Quality, North Carolina Department of Environment and Natural Resources (NCDENR)

Document Control Number: EPA-HQ-OAR-2002-0058-3663-A2

Comment Excerpt Number: 23

Comment: Proposing to exempt any boiler or process heater used as control device to comply with standards issued under part 60, 61, or 63 of the CAA, provided that at least 50% of heat input to boiler is provided by gas stream subject to standards under those parts.

NC DAQ concurs with EPA's proposed approach on this issue.

Response: The EPA thanks the commenter for their support.

2D. Exempted Residential boilers

Commenter Name: Pamela Lacey

Commenter Affiliation: American Gas Association (AGA)

Document Control Number: EPA-HQ-OAR-2002-0058-3672-A2

Comment Excerpt Number: 4

Comment: AGA appreciates EPA's proposal to exempt "residential boilers" meaning boilers" used in a dwelling containing four or fewer family units, to provide heat and/or hot water" from the major source rule. This would cover natural gas-fired furnaces and water heaters in dwellings

located at a university campus, military base or other institutional facility. However, we had thought the 2011 final rule would also exclude these residential-style appliances *wherever they are located* at a major source, including for example at a small office building or trailer at a utility service center or a small lab where the appliances are used to provide heat or hot water – and not just when located in a dwelling. While performing tune-ups once every five years will make this more workable, our members are concerned that keeping track of reporting for hundreds of small units that heat 100 gallons of water or less could be very burdensome. We question the utility of this paperwork burden and urge EPA to exempt these very small units regardless of where they are located.

Response: The rule does contain an exemption for "residential type" hot water heaters that are located at industrial, commercial, and institutional facilities, because such heaters are not part of the listed source category. Hot water heaters are defined in the rule as gas or liquid units with a capacity of less than 120 gallons of water. Therefore, the hundreds of small units that heat 100 gallons of water or less mentioned by the commenter would be exempt.

Commenter Name: Arthur N. Marin

Commenter Affiliation: Northeast States for Coordinated Air Use Management (NESCAUM)

Document Control Number: EPA-HQ-OAR-2002-0058-3506-A1

Comment Excerpt Number: 8

Comment: Inclusion of Boilers at Industrial, Commercial, and Institutional in the Residential Exemption under the Area Source Rule [Note: Same exemption proposed in Major Source Rule.]

The EPA is proposing to include large boilers at dwellings at industrial, commercial, and institutional facilities in the list of exemptions in the area source rule. Specifically, the EPA proposes to define a residential boiler according to the following definition.

Residential boiler means a boiler used in a dwelling containing four or fewer family units to provide heat and/or hot water. This definition includes boilers used primarily to provide heat and/or hot water for a dwelling containing four or fewer families located at an institutional facility (e.g., university campus, military base, church grounds) or commercial/industrial facility (e.g., farm) (76 FR 80548).

NESCAUM believes that almost all residential units will be exempted under the proposed reconsidered boiler definition, which specifies that units with heat inputs of 1.6 MMBtu/h and larger are subject to the rule (these units are much larger than a typical residential boiler). Hot water heaters below that threshold will be exempt. Therefore, by creating a duplicative exemption for residential units does not achieve additional environmental benefits, but does exempt some industrial, commercial, and institutional sources that should be subject to control. This change in definition would allow some significant sources to circumvent the rules. NESCAUM believes that sources should be regulated based on the size and emission potential of the unit, not the type of facility in which it resides.

Response: We disagree that the exemption for residential boilers is a duplicative exemption to the exemption for hot water heaters. The source categories covered by the boiler area source rule are industrial boilers located at area source facilities and institutional and commercial boilers located at area source facilities. Residential boilers are thus not covered by the rule, as they are

not part of the listed source category. We added the exemption for residential boilers to clarify that fact since applicability questions were raised by regulatory agencies and regulated facilities regarding boilers located at residences at institutional (military bases, universities) and commercial (farms) facilities. The exemption for hot water heaters pertains to heaters or boilers generating hot water. The exemption does not cover boilers generating steam for heating. Therefore, both exemptions are appropriate.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 22

Comment: Since a residential boiler is defined as a boiler providing only comfort heat and/or hot water for up to four residential units, we believe a boiler providing comfort heat and/or hot water for an office, workroom, control room, or similar space of similar size⁶ should also be exempted. Such small boilers, whether firing gas or liquid, have miniscule emissions and there is no environmental or health basis for imposing any requirements on such small emission sources. [Footnote 6: 6000 square feet is our estimate of the square footage of a typical four unit residence, but EPA may have data to allow specifying a heat duty, which would be a preferential way of defining the exclusion (i.e., Residential boiler means a boiler providing only comfort heat and/or hot water firing up to __ MMBTU/hr.)]

Response: See the responses to EPA-HQ-OAR-2002-0058-3506-A1, excerpt 8 and EPA-HQ-OAR-2002-0058-3672-A2, excerpt 4 for discussion.

Commenter Name: Arthur N. Marin

Commenter Affiliation: Northeast States for Coordinated Air Use Management (NESCAUM)

Document Control Number: EPA-HQ-OAR-2002-0058-3506-A1

Comment Excerpt Number: 9

Comment: In our region, there are many historically single unit residences that have been subdivided into several condominiums or apartments. The specification of a number of units as the threshold for exemption from the rule creates a situation where similar residences with similar boilers will be treated differently. In the extreme case, if an unusually large and heavily emitting unit were to reside in a 1-3 unit dwelling at an institution (e.g., a university), it would be appropriate to regulate that unit under this rule. That scenario is extremely unlikely given the proposed boiler definition in the reconsidered rule. The number of units a building is subdivided into does not have a bearing on the size or emissions of the boiler.

Therefore, the exemption for dwellings at industrial, commercial, and institutional boilers should be deleted from the final rule. NESCAUM suggests that the EPA abandon this approach for exempting residential units, and instead rely solely on the exemption for units below a unit-size threshold to exempt residential units.

Response: We disagree that the exemption should be deleted - See the response to comment EPA-HQ-OAR-2002-0058-3506-A1, excerpt 8. The boilers and process heaters source category

includes commercial facilities like apartment buildings and condominiums, but not single family residences. However, we do recognize that a single family residence could be subdivided into more than 4 living units. The definition of "residential boiler" in the final rule have been revised to include historically single unit residences that have been subdivided into several condominiums or apartments.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 21

Comment: EPA should finalize the proposed clarifications to the residential boiler exemption, but should extend the exclusion to small office or similar boilers.

EPA proposes some clarifications of what BPH are considered residential units and thus are exempt from the proposed rule. In particular, the revisions make clear that the exemption applies even if the unit is in a residence that is located at an institutional, commercial, or industrial site, for instance a residence at a farm or a university. This clarification is important and appropriate and should be finalized.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3672-A2, excerpt 4 for discussion.

Commenter Name: Heather Parent

Commenter Affiliation: Maine Department of Environmental Protection

Document Control Number: EPA-HQ-OAR-2002-0058-3691-A2

Comment Excerpt Number: 11

Comment: While Maine DEP supports exempting small units from the Major Source Boiler MACT, we recommend combining and simplifying the definitions of hot water heater and residential boiler to further clarify which units will be exempt from the rule. EPA should apply a heat input capacity threshold and remove the ambiguous language in the definition. Maine DEP also recommends that the exemption apply to all units under a certain size regardless of the type of fuel that is fired in the unit (i.e., gaseous, liquid, and solid fuel fired under a certain capacity should be exempt).

Response: The EPA thanks the commenter for their support. As for combining the two definitions, see the response to comment EPA-HQ-OAR-2002-0058-3506-A1, excerpt 8. The definition of "hot water heater" in the final rule has been revised to include biomass in the type of fuel included in the definition.

Commenter Name: Jessica Bridges

Commenter Affiliation: United States Clean Heat & Power Association (USCHPA)

Document Control Number: EPA-HQ-OAR-2002-0058-3501-A1

Comment Excerpt Number: 18

Comment: EPA has proposed that residential boilers be exempted from the major source and the area rule and is proposing to define residential boiler as follows:

Residential boiler means a boiler, used in a dwelling containing four or fewer family units, to provide heat and/ or hot water. This definition includes boilers used primarily to provide heat and/or hot water for a dwelling containing four or fewer families located at an institutional facility (e.g., university campus, military base, church grounds) or commercial/ industrial facility (e.g., farm).

Congress encouraged exploration of the use of small-scale combined heat and power in residential heating appliances in EPACT (2005) Section 923.⁹

USCHPA is cognizant that advances in residential micro-combined heat and power technology have led since 2005 to the installation more than 120,000 systems in residences globally. These systems function with the heat/or hot water system. The description above aptly applies to these installations. We recommend that the definition be modified by the insertion of the words "and/or as part of a residential combined heat and power system" after the words "hot water".

Residential boiler means a boiler, used in a dwelling containing four or fewer family units, to provide heat and/ or hot water and/oras part of a residential combined heat and power system. This definition includes boilers used primarily to provide heat and/or hot water for a dwelling containing four or fewer families located at an institutional facility (e.g., university campus, military base, church grounds) or commercial/industrial facility (e.g., farm).

[Footnote]

(9) 42 USC § 16213 - MICRO-COGENERATION ENERGY TECHNOLOGY

Response: We agree with the commenter and have revised the definition of residential boiler to include language for "residential combined heat and power system."

Commenter Name: Felix Mestey, on behalf of Donald R. Schregardus

Commenter Affiliation: Clean Air Act Services Steering Committee, Department of Defense (DoD)

Document Control Number: EPA-HQ-OAR-2002-0058-3427

Comment Excerpt Number: 14

Comment: DoD supports EPA's decision to exempt residential boilers from the requirements of the major source Boiler MACT [§63.7341(n)]. The time, effort, and money involved in tuning up residential units located on a military base annually or biennially would be substantial and potentially disruptive to the lives of the families that reside in those dwellings (military housing).

Response: The EPA thanks the commenter for their support.

Commenter Name: Timothy Serie

Commenter Affiliation: American Coatings Association (ACA)

Document Control Number: EPA-HQ-OAR-2002-0058-3502-A1

Comment Excerpt Number: 13

Comment: ACA generally supports the following proposed changes in the Boiler MACT rule:

- Exemption of residential boilers from the rule

Response: The EPA thanks the commenter for their support.

Commenter Name: Arthur N. Marin

Commenter Affiliation: Northeast States for Coordinated Air Use Management (NESCAUM)

Document Control Number: EPA-HQ-OAR-2002-0058-3506-A1

Comment Excerpt Number: 2

Comment: Under the reconsidered area source rule, the EPA proposes to change the definition of hot water heaters (76 FR 80547), which are exempted from the area source rule requirements. The proposal creates a clear line to define hot water heaters exempt from the rule as units with heat input capacity below 1.6 million British thermal units per hour (MMBtu/h). NESCAUM supports the change in definition with regard to the 1.6 MMBtu/h heat input threshold. [Note: The same change was made in the major source rule.]

Response: The EPA thanks the commenter for their support.

Commenter Name: Tangela Niemann

Commenter Affiliation: Texas Commission on Environmental Quality (TCEQ)

Document Control Number: EPA-HQ-OAR-2002-0058-3594-A3

Comment Excerpt Number: 1

Comment: The TCEQ supports the proposed new exemptions for temporary and residential boilers to clarify the rule and exempting sources with insignificant emissions.

Response: The EPA thanks the commenter for their support.

2E. Comparable Fuels

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 122

Comment: ACC appreciates EPA's clarification in the preamble that boilers and process heaters firing comparable fuels (secondary materials that have properties similar to fuel oil) are covered under the Boiler MACT and not under the hazardous waste combustor MACT. It is appropriate to treat units burning comparable fuel as liquid units. 76 Fed. Reg. 80616. ACC requests that EPA provide this clarification in the regulatory text with reference to specifications provided in 40 CFR 261.38.

Response: The EPA has provided this clarification in the final rule. The definition of "Liquid fuel" has been revised to include "comparable fuels as defined under 40 CFR 261.38."

Commenter Name: Vickie Woods

Commenter Affiliation: Division of Air Quality, North Carolina Department of Environment and Natural Resources (NCDENR)

Document Control Number: EPA-HQ-OAR-2002-0058-3663-A2

Comment Excerpt Number: 24

Comment: Section 261.38 states hazardous secondary materials (i.e., spent materials, sludges and byproducts) -with fuel value and whose hazardous constituent levels are comparable to those found in fuel oil that could be burned in their place -- are not solid wastes and hence not hazardous wastes under RCRA Subtitle C. These materials are called comparable fuels. EPA clarifies units burning comparable fuels are covered by the Boiler MACT.

NC DAQ supports this definition and clarification of comparable fuels.

Response: The EPA thanks the commenter for their support.

2Z. Out of Scope: Legal and Applicability Issues

Commenter Name: John V. Corra, Director

Commenter Affiliation: State of Wyoming Department of Environmental Quality

Document Control Number: EPA-HQ-OAR-2002-0058-3435-A1

Comment Excerpt Number: 4

Comment: Wyoming suggests the addition of a small boiler and process heater exemption. The exemption of boilers and process heaters less than 2 MMBtu/hour will somewhat alleviate the recordkeeping and tracking burden on both the State and industry.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Randall D. Quintrell

Commenter Affiliation: Georgia Paper & Forest Products Association

Document Control Number: EPA-HQ-OAR-2002-0058-3451-A1

Comment Excerpt Number: 1

Comment: This proposed rule imposes hazardous air pollutant (HAP) emissions limits that are much tighter than needed to protect human health and the environment.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Traylor Champion

Commenter Affiliation: Georgia-Pacific LLC (GP)

Document Control Number: EPA-HQ-OAR-2002-0058-3465-A1

Comment Excerpt Number: 21

Comment: GP is requesting that EPA consider exempting from these regulations units that have a heat input of less than 5.0 MMBtu/hr. These units are typically listed as insignificant activities in a Title V permit and HAP emissions are essentially zero. An example of a unit that will be unnecessarily regulated is a propane vaporizer. These units are simply small propane burners that are used to indirectly heat propane such that it is vaporized from a liquid to gas for use in larger burner systems. To require routine tune-ups is unnecessary and overly burdensome to the regulated community. While this example provided is a very small unit (less than 0.15 MMBtu/hr), it demonstrates the burden placed on the regulated community with no corresponding environmental benefits.

GP requests that EPA establish a minimum applicable size criterion that would exempt very small sources for which regulation would achieve limited environmental benefit while imposing unnecessary and excessive regulatory burden.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: David L. Meeker

Commenter Affiliation: National Renderers Association (NRA)

Document Control Number: EPA-HQ-OAR-2002-0058-3476-A1

Comment Excerpt Number: 9

Comment: The Boiler MACT includes the following definition for Other Gas 1 fuel under §63.7575:

Other gas 1 fuel means a gaseous fuel that is not natural gas or refinery gas and does not exceed the maximum concentration of 40 micrograms/cubic meters of mercury.

The mercury content for defining a fuel as Other Gas 1 instead of Gas 2 identifies a representative "threshold" for a significant HAP content (mercury) for a fuel (Gas 1) that is not subject to an emissions limitation. If an "other" gas fuel does not meet the definition of an Other Gas 1 fuel, the unit is classified as a Gas 2 (other) fuel.⁸ A maximum concentration of 40 µg/m³ for the mercury content in Other Gas 1 fuel is equivalent to 2.5e-06 lb/MMBtu mercury emission factor assuming a heating value of 1,000 Btu/scf.

Processed fats are not gaseous fuels, but the mercury content in the processed fats samples was below a 5 ppbw detection limit. Even if we assume that the mercury was present at this detection limit of 5 ppbw, and we apply a conservative heating value of 17,000 Btu/lb, this is approximately 3.0e-07 lb/MMBtu – an order of magnitude less than the EPA-defined threshold for natural gas-equivalency. Since Gas 1 units are subject to work practice standards under the Boiler MACT, the NRA has demonstrated the mercury (metal HAP) content identified in various types of processed fats samples analyzed is similar (or less than) in mercury content to Other Gas 1 fuel, and should be similarly regulated (work practice standards).

[Footnote 8: New and existing Gas 2 (other) units are subject to emissions limitations for PM, CO, HCl, mercury, and dioxin/furans as defined in Tables 1 and 2 to NESHAP Subpart DDDDD, respectively.]

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: David L. Meeker

Commenter Affiliation: National Renderers Association (NRA)

Document Control Number: EPA-HQ-OAR-2002-0058-3476-A1

Comment Excerpt Number: 11

Comment: The rendering industry routinely monitors processed fats for the presence of acid gas HAP-forming constituents, specifically chlorinated pesticides and polychlorinated biphenyls (PCBs). The U.S. Food and Drug Administration (FDA) considers any rendered product contaminated with pesticides/PCBs as adulterated under the Food Drug and Cosmetic Act if they exceed tolerances established by the FDA or EPA (40 CFR Part 180). The testing of these products to verify compliance is an integral part of the industry's Good Manufacturing Practices (GMP). The GMP varies from one NRA member to another and includes, but is not limited to, the following:

- Testing each production run before it is released for sale;
- Testing each load prior to shipment;
- Testing a weekly composite sample of each type of processed fat produced; and
- Periodic, or spot, testing.

Each year NRA members test several thousand samples of processed fats for the presence of the chlorinated pesticides and PCBs as a GMP to assure compliance with tolerances established by the FDA or EPA. Three of the aforementioned processed fats samples (Yellow Grease No. 1, Poultry Grease, and Tallow No. 1) were also analyzed using ASTM D 4327 and indicated no detected chloride content.⁹ The methods used for chlorinated pesticide testing are also recognized by the World Health Organization (WHO) as an approved method for the screening of dioxins and dioxin like substances and therefore the referenced test results also indicate these compounds are not typically present in processed fats.

Compared to natural gas from the EPA Emissions Database, the maximum chlorine content in 12 natural gas fuel samples analyzed is 82 ppmw. For 340 petroleum-based liquid fuel samples analyzed, the maximum chlorine content is 1,260 ppmw.¹⁰

The NRA considers these GMP practices and results of monitoring processed fats for chlorinated pesticides and PCBs as demonstrating that acid gas HAP-forming constituents are insignificant. Due to insignificant content of chlorinated compounds (based on separate FDA requirements for the industry) in the processed fats prior to combustion, the NRA believes the correlation to insignificant acid gas HAP emissions from boilers burning processed fats is direct. Any acid gas HAP emissions result from the actual chlorinated compound content in the fuel source combusted and are not produced by combustion due to insignificant levels of chlorinated compounds in the fuel source. Without high content of acid gas HAP-forming constituents in processed fats due to industry quality requirements, boilers burning processed fats do not emit significant acid gas HAP emissions. Therefore, similar to Gas 1 units, these processed fat-fired

boilers should also be subject to work practice standards and not an HCl emissions limitation under the Boiler MACT.

[Footnote 9: Detection level or threshold is 10 ppm for ASTM D 4327.]

[Footnote 10: The petroleum-based liquid fuels includes No. 6 fuel oil, No. 2 distillate, diesel fuel, fuel oil, biodiesel, No. 4 fuel oil, and No. 5 fuel oil, as identified in the EPA Emissions Database.]

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: David L. Meeker

Commenter Affiliation: National Renderers Association (NRA)

Document Control Number: EPA-HQ-OAR-2002-0058-3476-A1

Comment Excerpt Number: 12

Comment: EPA is required to establish emission standards for organic HAP emissions (compliance with the Boiler MACT demonstrated using CO surrogate pollutant for subject subcategories). Organic HAP emissions, such as polycyclic organic compounds (POCs) (as 7-PAH and referred to as polycyclic organic matter [POM]) and ethylene dioxide, are due to incomplete combustion of fossil fuels and solid vegetable matter that contains lignin and cellulose. Processed fats contain triglyceride mono, di, and free fatty acids. Acrolein (or 2-propenal) can be formed when processed fats fuel is burned due to decomposition of the triglyceride glycerin backbone. However, this is not a cyclic compound and therefore does not meet the definition of a POC (or POM). As such, the pollutant generation of these organic HAP from processed fats combustion is analogous to natural gas combustion. EPA previously found that these emissions were insignificant from natural gas combustion, and a similar argument can be made for processed fats fuel combustion. Therefore, similar to Gas 1 units, these processed fat-fired boilers should also be subject to work practice standards and not a CO emissions limitation under the Boiler MACT.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Barry Christensen

Commenter Affiliation: Occidental Chemical Corporation (OCC)

Document Control Number: EPA-HQ-OAR-2002-0058-3477-A1

Comment Excerpt Number: 8

Comment: OCC requests clarification of how industrial cogeneration units, both turbines and HRSGs, are affected by this revised rule. Our prior understanding took into consideration that EPA intended for these industrial cogeneration units to be subject to the Subpart YYYYY Turbine MACT Standard and not covered by this rule. However, the exclusion in the proposed rule expressly addresses only EGUs that sell more than one third of their power to the grid. Therefore, we would appreciate language in the final rule that reiterates EPA's previously stated intent, which we are relying upon, that all EGUs, including EGUs that sell less than 1/3 of their

power to the grid, are exempt from the final boiler MACT rule. As stated previously, our turbines operate with HRSGs and are potentially subject to this rule.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Peter Pagano

Commenter Affiliation: American Iron and Steel Institute (AISI)

Document Control Number: EPA-HQ-OAR-2002-0058-3490-A1

Comment Excerpt Number: 10

Comment: Fuel averaging across multiple units should be allowed as a means of qualifying as a Blast Furnace Gas Fuel-Fired Boiler/Process Heater.

As noted above, while AISI strongly supports a BFG exemption, the exemption requires revision to further effectuate facility-wide emission reductions and operational flexibility. Because multiple boilers, at times, operate together as a system to produce steam, AISI believes it is most appropriate to allow fuel averaging across multiple units for the BFG exemption to apply. In such situations, based upon the gas piping network and the availability of BFG, some boilers are always first to receive BFG while others may continue to be supplemented by other fuels, such as natural gas. In such instances, the use of BFG across the units is not necessarily equal which could result in some boilers firing well over 90%, by volume, of BFG, while other boilers may be firing less than 90% by volume, with an average over the multiple boilers exceeding 90%. If the BFG exemption were not to apply across multiple units, it could act as a disincentive for the continued beneficial reuse of BFG on certain individual boilers, which could result in BFG unnecessarily being flared.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Peter Pagano

Commenter Affiliation: American Iron and Steel Institute (AISI)

Document Control Number: EPA-HQ-OAR-2002-0058-3490-A1

Comment Excerpt Number: 28

Comment: AISI is concerned that carbon monoxide standards in the Boiler MACT are too stringent to accommodate the full range of low-NOx technology that will be needed to meet the next generation of regulatory requirements applied to the variety of sources facing NOx control requirements. EPA should excuse affected sources from the CO emission limits when they can demonstrate that these limits conflict with an applicable NOx control requirement. Regular tune-ups should be sufficient to ensure that the boiler is optimizing combustion efficiency within the constraints of its low-NOx technology.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Peter Pagano
Commenter Affiliation: American Iron and Steel Institute (AISI)
Document Control Number: EPA-HQ-OAR-2002-0058-3490-A1
Comment Excerpt Number: 29

Comment: In the iron and steel industry, low-NO_x process gases are also used to meet NO_x control requirements particularly during ozone seasons. *See e.g.*, 326 IAC 10-3 (Indiana rule requiring at least 50% blast furnace gas during the ozone season to meet NO_x control requirements). While blast furnace gas is exempt from the Boiler MACT definition of gaseous fuel, and boilers using 90% blast furnace gas or more are expressly excluded from Boiler MACT, mixed gas units that include some blast furnace gas with other process gases may still be subject to CO emission limits under the gas 2 fuel subcategory. Blast furnace gas is a low-NO_x fuel that can be added to mixed gas as a NO_x control strategy. However, since CO is one of the primary constituents of blast furnace gas, AISI members may not be able to control NO_x using this process gas without violating the stringent Boiler MACT CO emission limits. EPA should exempt affected boilers and process heaters from the CO emission limits when they are using blast furnace gas and are not otherwise exempt.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Peter Pagano
Commenter Affiliation: American Iron and Steel Institute (AISI)
Document Control Number: EPA-HQ-OAR-2002-0058-3490-A1
Comment Excerpt Number: 36

Comment: EPA should clarify that an affected unit that cogenerates steam and electricity could be subject to the Boiler MACT, and not the MACT for Electric Utility Steam Generating Units, when the unit supplies less than one-third of its potential electric output capacity *on an annual average basis*.

Electric Utility Steam Generating Units ("EGUs") are not subject to the Boiler MACT rule because they have their own EGU MACT rule. Cogeneration units can be caught between the two rules with applicability determined based on whether the unit supplies more than one-third of its potential electric output capacity to a utility power distribution system (the "grid") for sale. Unfortunately, the CAA and the EGU MACT have been silent on the period of time to be used to determine whether more than one third of potential electric output capacity has been sent to the grid. AISI encourages EPA to use the Boiler MACT final rule to clarify its intent to use an annual averaging period for this calculation as EPA did when applying this same threshold to cogeneration units under the Acid Rain program. This will support use of cogeneration systems to reduce energy cost, support energy efficiency initiatives and environmental benefits.

Cogeneration units improve energy efficiency by utilizing steam for an industrial purpose while also generating electricity. AISI members are large energy consumers and they are constantly looking for ways to improve energy efficiency and reduce energy costs. Cogenerating electricity from waste heat and steam in our industry has been, and will continue to be, a focus of capital investment that reduces cost while improving the environment. In most instances, the facility

operating the cogeneration system has sufficient appetite for the electricity generated that only a minor amount is sent to the grid. However, there are circumstances when sending more than one-third of potential electric output capacity to the grid is consistent with our Nation's goals of energy efficiency and grid reliability. EPA can accommodate these circumstances by clarifying that "one-third of its potential output capacity" is to be determined on an annual average basis consistent with the CAA Acid Rain provisions.

By connecting to the grid, cogeneration units have the opportunity to contribute to the reliable distribution of electricity. Concerns regarding grid stability have been debated recently as costly environmental regulations force many older units to shutdown. As our national base load capacity decreases, distribution systems increasingly will need to rely on backup power supplies during high demand periods to sustain a reliable grid. Cogeneration systems have unused capacity that can be tapped for that back up system. The Boiler MACT rule should not force a cogeneration unit into the EGU MACT rule merely because it utilizes that backup capacity to support the electricity grid in times of high demand.

Local generation capacity also must be called upon when regional electricity distribution is interrupted. As we witness during significant regional blackouts, local generation can provide the necessary electricity to keep hospitals and other essential services operating. Cogeneration units should not face a new regulatory regime by sharing their unused capacity (above one-third of each unit's potential output) to respond appropriately to demand for local generation. We cannot know how long such episodes may last. The simple solution would be to clarify that a cogeneration unit may consider its output on an annual average basis to determine if it has contributed more than one third of its potential electric output capacity to the grid.

Cogeneration units could also provide a benefit to energy consumers by providing additional supply during peak usage periods. By providing additional supply to the grid as prices start to increase, cogeneration units contribute to price stability and mitigate the economic burden of high electric costs during periods when supply is otherwise constrained. This produces benefits throughout the economy and helps energy intensive industries compete in the global market.

Finally, as the iron and steel industry and others are considering new investments in cogeneration technology, the return on investment is critical to deploying limited capital. The return on investment is quicker, and capital is more likely to be invested, if the cogeneration unit can provide more electricity to the grid during peak demand periods that command a higher price per kW-hour. EPA can encourage energy efficiency investments, reduce the peak cost of electricity, and take an important step to improve grid reliability by establishing an annual average as the basis for determining if a unit is providing more than one-third of its potential electric output capacity to the grid. The Clean Air Act definition of "Electric Utility Steam Generating Unit" does not preclude an annual averaging period. Clean Air Act Section 112(b)(8) states in pertinent part, "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." Congress did not specify the method by which to calculate the fraction of a cogeneration unit's potential electric output capacity supplied to the grid. EPA has the implied authority to add a reasonable calculation method to implement Congress' intent. When EPA faced this same situation under the Acid Rain program, it issued a rule that allowed a cogeneration unit to evaluate its electric output on an annual average basis over three years to determine if it met the

one-third threshold for the cogeneration exemption. *See* 40 CFR 72.6. Like Section 112(b), the Acid Rain portion of the Clean Air Act defined the utility unit in reference to one-third of potential output capacity without specifying an averaging period. *See* 42 U.S.C. 7651a(17). EPA utilized its inferred authority to set an annual average calculated over three years for the Acid Rain program; and EPA should do the same under the Boiler MACT rule.

The EGU MACT is currently silent on the averaging period, like the Clean Air Act. This does not preclude EPA from using the Boiler MACT to clarify an averaging period and to express its intention that the silence in the EGU MACT be interpreted consistent with the express clarification in the Boiler MACT rule. This has important benefits for grid reliability, energy price stability, and it creates an incentive for energy efficiency that produces significant environmental benefits. We urge you to place a special emphasis on these measures because they simultaneously improve energy efficiency and reduce emissions while producing high quality distributed power generation. Cogeneration and waste heat recovery can be a superior substitute for power produced from inefficient conventional electric power generation.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: N.W. Bernstein & Associates, LLC

Commenter Affiliation: Eco Power Solutions (USA) Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3499-A1

Comment Excerpt Number: 3

Comment: There is a Strong Congressional Policy Favoring Innovation in Emission Control Technology. The Supreme Court has summarized the point in *Chem. Mfrs. Ass'n v. Natural Res. Def. Council, Inc.*, 470 U.S. 116, 155-56, 105 S.Ct. 1102, 1123 (1985).

The legislative history [of the CAA] also makes clear why Congress found it so important that the standards be set for "categories" of dischargers, and not for individual dischargers. Congress intended to use the standards as a means to "force" the introduction of more effective pollution control technology. Thus, Congress directed EPA to establish BPT levels by reference to "the average of the best existing performance by plants of various sizes, ages, and unit processes within each industrial category." 118 Cong.Rec. 33696 (1972) Leg. Hist. 169 (Sen. Muskie). In establishing BAT levels, it directed EPA to look at "the best performer in an industrial category." 118 Cong.Rec. 33696 (1972) Leg.Hist. 170. By requiring that the standards be set by reference to either the "average of the best" or very "best" technology, the Act seeks to foster technological innovation. 118 Cong.Rec. 33696 (1972) Leg.Hist. 170. See generally La Pierre, Technology-Forcing and Federal Environmental Protection Statutes, 62 Iowa L.Rev. 771, 805-829 (1977); Note, Forcing-Technology: The Clean Air Act Experience, 88 Yale L.J. 1713 (1979).

Similarly in order to encourage the use of innovative multi-pollutant control technologies and other innovative technologies, EPA in the final EGU NSPS rule, 40 C.F.R. Part 60, provided for commercial demonstration permits to a limited number of EGU operators that deployed innovative multi-pollutant control technologies and other innovative technologies. As EPA explained in its proposal for the EGU rule:

[T]o encourage the continued development of new technologies that show promise in achieving levels of performance comparable to those of existing technologies, but at lower cost or with other offsetting environmental or energy benefits, special provisions are needed which encourage the development and use of new technologies, while ensuring that emissions will be minimized. 76 Fed. Reg. at 25,068-69.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: N.W. Bernstein & Associates, LLC

Commenter Affiliation: Eco Power Solutions (USA) Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3499-A1

Comment Excerpt Number: 6

Comment: There is a strong Congressional policy favoring the adoption and employment of new technology such as Eco Power's COMPLY 2000® technology, and EPA has recognized and sought to accommodate that need in the EGU Rule. The benefits of multipollutant removal technology are not only that it achieves multi-pollutant control and reduces CO₂ emissions by between 10% and 15% without sequestration, but it also avoids the collateral harm to the environment caused by conventional emission control technology. So for example, Eco Power's COMPLY 2000® is at least as effective as conventional wet flue gas desulfurization (WFGD) for SO₂ and selective catalytic reduction (SCR) for NO_x.⁵ Unlike WFGD, however, Eco Power's technology does not increase CO₂ emissions (*see* Available and Emerging Technologies for Reducing Greenhouse Gas Emissions From Coal-Fired Electric Generating Units, Office of Air and Radiation, US Environmental Protection Agency, October 2010, p. 23) and unlike WFGD, it does not significantly increase water usage (EPA Draft BACT GHG Guidance, p. 41, fn. 99). Additionally the water pollution problems created by WFGDs have been widely reported in the news media (*see* Attachment 2 to these comments, "Cleansing the Air at the Expense of Waterways," The New York Times, October 13, 2009). In contrast to WFGDs, COMPLY 2000® consumes and discharges smaller amounts of water due to the nature of its process and, as noted above, reduces CO₂ by 10% - 15% without sequestration. EPA should spell out these reasons in detail in justifying its rescission of the Boiler Rule in its entirety.

[Footnote]

(5) In its study of Applicability and Feasibility of NO_x and SO₂ and PM Emissions Control Technologies for Industrial, Commercial and Institutional Boilers (ICI) the Northeast States for Coordinated Air Usage Management (NESCAUM November 2008 revised January 2009) assumed higher than 90% NO_x reduction for SCR (NESCAUM Sec. 3.1 at 3-2) and 90% - 95% SO₂ removal for WFGD but only 70% - 90% for dry scrubbers (NESCAUM Sec. 3.6 at 3-12). NESCAUM did not provide comparative data for mercury reduction. As noted above, Eco Power's COMPLY 2000® achieves greater reduction in all of the above pollutants.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Arthur N. Marin

Commenter Affiliation: Northeast States for Coordinated Air Use Management (NESCAUM)

Document Control Number: EPA-HQ-OAR-2002-0058-3506-A1

Comment Excerpt Number: 10

Comment: Exemption for Temporary Boilers in the Area Source Rule [Note:Same exemption proposed in Major Source Rule.]

The EPA is proposing to amend the area source rule at 40 CFR 63.11195 by adding temporary boilers to the list of boilers not subject to regulation (76 FR 80535). This change would make the major and area source rules' treatments of temporary boilers consistent. In justifying this change, the EPA indicated that temporary boilers are typically located on site for less than a year and are not included in the facility's operating permit. The EPA defined a temporary boiler as:

Temporary boiler means any gaseous or liquid fuel boiler that is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A boiler is not a temporary boiler if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

(2) The boiler or a replacement remains at a location for more than 12 consecutive months. Any temporary boiler that replaces a temporary boiler at a location and performs the same or similar function will be included in calculating the consecutive time period.

(3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.

(4) The equipment is moved from one location to another in an attempt to circumvent the residence time requirements of this definition.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 30

Comment: *EPA Could Extend the Work Practice Approach Used for Gas 1 to Include Distillate Oil Fired Units*

Response: EPA has proposed work practice standards for certain existing units. The proposed work practice standard would include the implementation of a tune-up program. In order to further incentivize the use of clean fuels, EPA should extend the work practice standard to cover ultra-low sulfur distillate oil-fired units. EPA has established the MACT floors for liquid-fired units based on fuels that have low sulfur, chloride, and mercury content. As a result, the MACT

floors are based on fuel characteristics and not on consideration of emission controls employed by the units (in fact, the light liquid floor units have no emission controls). Considering this, EPA should not impose controls on boilers that burn a clean liquid fuel such as distillate fuel with low sulfur, chloride, and mercury content. In many cases it is difficult, if not impossible, to design emissions controls for such low contaminant levels, since the levels in the oils are already below detection levels.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 33

Comment: ACC reiterates its strongly-held view that work practices are appropriate for units burning other process gases as previously noted, and for the reasons below:

- Many petrochemical and chemical process gases have HAP emissions at the ultra-low levels of natural gas. Measuring these ultra-low levels of HAP emissions is not possible using existing methods.
- Integrated chemical plants typically use process gases as fuels from processing areas as fuels in boilers and process heaters. The use of these fuels is critical to maintaining energy efficiency at these sites. Based on the extremely low numeric standards proposed for units designed to burn Gas 2 fuel in both the original proposal and in this reconsideration proposal and the uncertainty surrounding the efficacy of expensive add-on controls, many facilities would be forced to use these process gases in a non-optimal manner, such as routing this fuel to flares or other combustion sources at the site, and replacing the lost fuel value by burning more natural gas. Forcing this switch is contrary to the nation's goal of reducing fossil fuel use and encouraging use of alternate energy sources (especially landfill gas).
- Facilities with process gas-fired units are very concerned over the feasibility of ensuring continuous compliance with such low Gas 2 limits.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Ahmed Idriss, Capital Power Corporation

Commenter Affiliation: CPI USA North Carolina (CPI NC)

Document Control Number: EPA-HQ-OAR-2002-0058-3524-A1

Comment Excerpt Number: 10

Comment: Finally, given the complexity of the Proposed Rule, CPI NC is concerned that ample time was not given by the EPA for CPI NC to fully analyze and understand the effects of the Proposed Rule on CPI NC's facilities. In this regard, CPI NC supports and incorporates the Council of Industrial Boiler Owners' January 18, 2012 comments, regarding insufficient time to comment on the Proposed Rule.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Mary Sullivan Douglas
Commenter Affiliation: National Association of Clean Air Agencies (NACAA)
Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1
Comment Excerpt Number: 61

Comment: NACAA has reviewed EPA's Response to Comments submitted in the 2011 rulemaking. We recognize that responding in detail to the many thousands of comments received in that rulemaking would be an enormous undertaking. As a consequence, however, EPA has not provided a meaningful response to most of the comments submitted by NACAA. This makes it difficult to advance the issues that carry forward from that rulemaking to the present activity.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Bart Sponsellar
Commenter Affiliation: Wisconsin Department of Natural Resources (DNR)
Document Control Number: EPA-HQ-OAR-2002-0058-3527-A1
Comment Excerpt Number: 8

Comment: The Department believes that EPA does not have the information to characterize and regulate smaller biomass boilers. We believe there is considerable variability in small biomass boiler design, operation, and fuel quality and it is even questionable if these sources can be tuned according to the rule. We suggest that EPA suspend regulating boilers smaller than 5 mmBtu/hr under this rulemaking and proceed with collecting the necessary information. This threshold is suggested simply because EPA determined that below this size it is appropriate to reduce the tune-up frequency for oil boilers. In many cases we believe the contaminant content of biomass will be closer to oil than to coal fuels for these small sources.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Bart Sponsellar
Commenter Affiliation: Wisconsin Department of Natural Resources
Document Control Number: EPA-HQ-OAR-2002-0058-3527-A2
Comment Excerpt Number: 10

Comment: The Department's preferred approach is to establish work practices for all biomass dedicated sources and all pollutants. This conclusion is based on the fact that the content of fuel based pollutants including chlorides, mercury, and non-mercury metals will vary greatly between specific biomass sources and even vary based on the environmental conditions to which the biomass is exposed. Therefore conditions at one source cannot be expected to always be true for other sources in the subcategory. The Department suggests that a biomass source should be subject to only a work practice limit if the material is clean or virgin material and has not been exposed to pathways for contamination by the pollutants in question. Appropriate work practices may include material handling practices and operating particulate control equipment. If the biomass is not deemed clean, the source should be subject to alternative emission limitations as proposed based on the biomass subcategory floor determinations.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Bart Sponsellar

Commenter Affiliation: Wisconsin Department of Natural Resources

Document Control Number: EPA-HQ-OAR-2002-0058-3527-A2

Comment Excerpt Number: 11

Comment: The Department suggests a work practice with alternate emission limitation by subcategory, can also be applied in the case of carbon monoxide emission requirements [at biomass units]. We believe the CO emission data for biomass also shows that concentrations related to good combustion will vary significantly by each biomass fuel type and also the quality of the fuel over time. To some extent variability could be controlled by specifying fuel parameters such as moisture content. But the Department believes such parameters must be determined by each source. The more practical approach to achieving good combustion is to require continuous CO and O2 emissions monitoring and trimming of combustion air according to a good combustion plan. This approach is much more effective in maintaining good combustion while burning variable fuels as compared to a single stack test while burning optimal fuels. Therefore, the Department believes that a combustion monitoring system of a CO and O2 analyzer system (non-CEM) is an appropriate carbon dioxide work practice requirement representing good combustion for biomass sources. As an alternative, a source can demonstrate compliance with the annual stack test emission limitation.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 4

Comment: Under basic principles of due process and administrative law, EPA has an obligation to provide the public with a reasonable opportunity to comment on proposed rules. Specifically, Congress requires EPA to give the public “a reasonable period . . . of at least 30 days” in which to comment on “any regulation” promulgated under the CAA.⁹ By the clear terms of the CAA, Congress indicates that 30 days is the minimum time necessary to give the public a reasonable opportunity to evaluate a proposed rule and provide adequate feedback to the Agency. Thus, a comment period meeting the statutory 30-day minimum would be reasonable for a single, ordinary proposed rule. Here, EPA has violated the clear terms of the CAA and deprived sources of a means to adequately protect their interests and rights in the administrative and judicial processes by providing 60 days of comment for four complex interrelated rules.

Under reconsideration, the rules are no less complex than when they were first proposed in June 2010. A 60-day comment period is particularly inadequate given their complexity, breadth of applicability, and economic impact. EPA has added data on reconsideration for 300 additional sources that must be reviewed and sources face the pressures of sorting complex data and developing thorough comments that address very technical issues. Although EPA released the

signed rule proposals almost one month prior to their publication in the Federal Register, it did not provide the majority of the supporting documentation for the proposed rules until publication on December 23, 2011, just two days before the holidays, effectively shortening the comment period. The four proposed rules under reconsideration make for an enormously broad and costly proposal, which would have a significant economic impact across numerous and diverse sectors of the US economy, with the boiler MACT rule alone imposing capital costs of more than \$5 billion and affecting nearly 200,000 sources, according to EPA. 76 Fed. Reg. 80622.

This economic impact alone, which CIBO estimates to be over \$14 billion,¹⁰ requires a comment period sufficient to ensure thorough consideration of the proposed rules. CIBO joined with 26 other entities and trade associations, representing tens of thousands of affected sources, to ask EPA to extend the comment period by 30 days and explaining in detail why the extra 30 days was needed and justified.¹¹ On February 14, 2011, just seven days before the comments were due, EPA denied the request.

Sources have done the best under the circumstances to develop thoughtful comments on their concerns and the specific requests for comment EPA made in the four rules, and where necessary or appropriate, and where time permitted, to compile data to support its positions. [Footnote 9: CAA §307; 42 U.S.C. § 7607(h) (2006).]

[Footnote 10: How Costs Were Determined for CIBO Boiler MACT Study, January 2012, Appendix C of submittal.]

[Footnote 11: See January 18, 2012 Letter of 27 Organizations to EPA, Appendix D of submittal.]

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 15

Comment: EPA should promulgate a *de minimis* exemption, not merely a work practice standard, for small boilers and process heaters of up to 10 MMBtu/hr or less. *Alabama Power Co. v. Costle*, 636 F.2d 323, 400 (D.C. Cir. 1979), clearly establishes EPA's authority to fashion *de minimis* and administrative necessity exemptions. In addition to the logistical issues involved with shutting down multiple small units in a facility at the same time, there is the considerable cost involved with performing the tune-ups. This significant cost produces only minimal corresponding reductions in HAP emissions. Tune-ups required under the current final and proposed rules will have only a limited effect on the HAP emissions from these small units. At least one CIBO member facility has estimated the cost of performing biennial tune-ups at \$20,000 per ton and quintennial tune-ups at \$8,000 per ton. The tune-up requirement results in a disproportionate expense in a very small portion of industry-wide HAP emissions.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1
Comment Excerpt Number: 17

Comment: Because some units, depending on their fuel, may be defined and therefore regulated as either section 112 boilers or section 129 incinerators, the regulations governing the process of changing source status affects both boilers and incinerators. EPA addresses this issue in the definitions section of the CISWI rule. This issue should be addressed and cross-referenced in the boiler MACT rule as well.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1
Comment Excerpt Number: 25

Comment: In order to further incentivize the use of clean fuels, EPA should extend the tune-up work practice standard to cover ultra-low sulfur distillate oil-fired units. EPA has established the MACT floors for liquid-fired units based on fuels that have low sulfur, chloride, and mercury content. As a result, the MACT floors are based on fuel characteristics and not on consideration of emission controls employed by the units (in fact, the light liquid floor units have no emission controls). Considering this, EPA should not impose controls on boilers that burn a clean liquid fuel such as distillate fuel with low sulfur, chloride, and mercury content. In many cases it is difficult, if not impossible, to design emissions controls for such low contaminant levels, since the levels in the oils are already below detection levels.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Kevin Bloomer
Commenter Affiliation: Westlake Chemical Corporation
Document Control Number: EPA-HQ-OAR-2002-0058-3535-A2
Comment Excerpt Number: 4

Comment: Due to the extensive nature of the proposed revisions to the rule, Westlake asks EPA to extend the comment period for this rulemaking. Westlake needs additional time to evaluate the MACT floor determination as it pertains to the emission limits for liquid fuels, and time to study the proposed CO limits and the impacts on our low-NOx burner equipped boilers. This specific topic is a major concern for owners of ICI boiler and process heaters located in ozone nonattainment areas that are affected by NOx Reasonably Available Control Technology regulations.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Edward W. Repa

Commenter Affiliation: National Solid Wastes Management Association (NSWMA)

Document Control Number: EPA-HQ-OAR-2002-0058-3539-A1

Comment Excerpt Number: 7

Comment: EPA has regulated HAP emissions from boilers and other LFG destruction equipment under various sections of the Clean Air Act. These include New Source Performance Standards and Maximum Achievable Control Technology Standards (e.g. boilers) for landfill gas. These standards adequately control HAP emissions. The proposed rule imposes additional emission limits on control devices and constitutes an impermissible duplication of emission limits under Section 112 of the Clean Air Act. In addition, the proposed boiler rules would result in fuel switching from LFG to fossil fuels that increases greenhouse gas emissions and criteria pollutants.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Tangela Niemann

Commenter Affiliation: Texas Commission on Environmental Quality (TCEQ)

Document Control Number: EPA-HQ-OAR-2002-0058-3594-A3

Comment Excerpt Number: 2

Comment: The EPA should include an exemption for electric boilers similar to the exemption proposed for 40 CFR 63 Subpart JJJJJ for boilers at area sources.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Tangela Niemann

Commenter Affiliation: Texas Commission on Environmental Quality (TCEQ)

Document Control Number: EPA-HQ-OAR-2002-0058-3594-A3

Comment Excerpt Number: 3

Comment: The TCEQ is concerned at the lack of a size exemption in the rule. While the emission standards and performance testing requirements in the rule only apply to units with a capacity of 10 million British thermal units per hour (MMBtu/hr) or greater, units less than 10 MMBtu/hr are still subject to certain requirements such as the periodic tune-up provisions and the energy assessment. Despite petitioners' subsequent requests for a *de minimis* size exemption, the current proposed rule revisions only change the frequency of the tune-up requirements for small units equal to or less than 10 MMBtu/hr. The EPA did not provide any rationale for denying petitioners' requests for including a size exemption in the current proposed revisions other than to indicate that "the EPA disagrees that small boilers should be exempt from the rule..." (76 FR 80614). However, in the March 21, 2011, *Federal Register* publication of the

final rule for 40 CFR 63 Subpart JJJJJ for the area source boiler NESHAP rule (76 FR 15568), the EPA's response to comments regarding a *de minimis* heat input level appears to indicate that the EPA believes that Federal Clean Air Act (FCAA), Section 112 mandates establishing standards (numeric limits or work practices) for all sources in the category or subcategory and that the EPA is prohibited from providing a size-based exemption. It is counter-intuitive for the EPA to argue that it may provide an exemption for boilers within a category based on limited use at the site (i.e., the current proposed temporary boiler exemption) yet a permanent boiler within the same category cannot be exempted based on limited size. Additionally, the EPA has already incorporated certain size-based criteria in other exemptions via the definitions used for those exemptions. The definition of *hot water heater* includes a maximum size of 120 gallons capacity that serves as a sized-based exemption for all hot water heaters 120 gallons or less. Similarly, the proposed addition of hot water boilers less than 1.6 MMBtu/hr to the definition of a *hot water heater* also establishes a sized-based exemption threshold.

The potential HAP emissions from such small units, particularly the natural gas-fired units, is significantly less than other units that are currently exempt from 40 CFR 63 Subpart DDDDD or that EPA has proposed exemptions for with the current rulemaking. As an example, the TCEQ points to one facility located in Texas that is listed in the appendices of the EPA's Technical Support Document (TSD) entitled *Revised (November 2011) Methodology for Estimating Cost and Emissions Impacts for Industrial, Commercial, Institutional Boilers and Process Heaters - National Emission Standards for Hazardous Air Pollutants – Major Source*. The facility is identified as being a major source of HAP subject to the rule with two 0.02 MMBtu/hr natural gas-fired boilers and one 5 MMBtu/hr process heater. Using the EPA's only emission data from the TSD document, the total HAP emissions from the two 0.02 MMBtu/hr natural gas-fired boilers combined is approximately 2 pounds per year. The total reduction in HAP emissions from these boilers as a result of applying the EPA tune-up requirement is 0.3 ounces per year. The EPA's own cost analysis data in the technical support document shows that the fuel savings for performing the tune-up requirements on the two small boilers is \$7 per year each, while the annualized costs for performing the tune-up requirements is \$2,875 for each boiler. Applying the tune-up requirements of 40 CFR 63 Subpart DDDDD to such small units is not cost-effective by any reasonable interpretation. The TCEQ encourages the EPA to incorporate a *de minimis* size-based exemption threshold into the final rule to eliminate burdensome and unnecessary requirements on owners and operators of small boilers and process heaters that have such insignificant emissions.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Mark Weiss

Commenter Affiliation: Reciprocal Energy Company

Document Control Number: EPA-HQ-OAR-2002-0058-3658-A2

Comment Excerpt Number: 6

Comment: The implementation of these standards within the Major Source Rules does not limit the application to "large scale" boilers because the designation of Source scale is defined by campus not boiler type. The application described below is designated as an Area Source but

the same boiler can fall under the Major Source Rule if it deployed on a Major Source site. Boilers larger than 10 MMBtu per hour are found at both Major and Area Source sites.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Annabeth Reitter

Commenter Affiliation: NewPage Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3662-A2

Comment Excerpt Number: 6

Comment: It was unreasonable for EPA to only provide 60 days for sources to review, understand and provide meaningful and thoughtful comments on not only the proposed reconsidered Boiler MACT rule but the other 3 proposed reconsideration rules in the Boiler MACT suite (Boiler MACT, CISWI, NHSM, Boiler GACT for area sources). NewPage like other affected sources, are impacted by one or more of these rules. Expecting sources to review, understand and provide detailed comments on these complex and integrated rules in only 60 days is an unreasonable expectation.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 1

Comment: As is obvious from the number of issues we and others have identified and the history of this rulemaking, these rules are very complex and difficult to understand and comment upon. Thus, we were extremely disappointed that the Agency failed to provide adequate time to comment. Many of the issues we have identified could not be dealt with in any but a superficial way as a result of the short 60 day comment period. While the draft rules were available a few weeks before Federal Register publication, none of the critical supporting documents were available until after publication, preventing the most productive use of that, albeit short, extra time. In an effort to learn from this experience, we recommend and request that EPA make supporting documents available in the docket at the same time the draft is released. Furthermore, we request EPA to seriously consider all of our and others comments and not ignore the majority of them because of a rush to finalize these rules.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Janice E. Nolen

Commenter Affiliation: American Lung Association

Document Control Number: EPA-HQ-OAR-2002-0058-3679-A2

Comment Excerpt Number: 1

Comment: We agree with the strong evidence the EPA provides to support their decision that action under Section 112 of the Clean Air Act is both appropriate and necessary to protect public health. The Clean Air Act requires that the EPA review and revise standards to see if they adequately protect public health from new sources of pollution and from hazardous air pollutants. Industrial, commercial, and institutional boilers and incinerators represent sources of such emissions that must be addressed under the law. It is long past time.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Janice E. Nolen

Commenter Affiliation: American Lung Association

Document Control Number: EPA-HQ-OAR-2002-0058-3679-A2

Comment Excerpt Number: 18

Comment: The American Lung Association supports the adoption of the safeguards against toxic air pollution from boilers and incinerators, as required under the Clean Air Act, to protect the public from life-threatening pollution and prevent tens of thousands of cases of illness and thousands of premature death each year. Curbing the different types of toxic pollution will yield tremendous benefits and significantly reduce adverse health effects.

The nation needs the EPA to adopt strong standards for toxic air pollution from boilers and incinerators to effectively protect the health of our communities. For over 20 years, the nation has waited on EPA to set standards to clean up toxic pollutants as required in the Clean Air Act Amendments of 1990. The EPA has a historic and momentous opportunity to clean the air of notoriously harmful pollutants that endanger human health. Our organizations call on the EPA to adopt strong, final rules and give our families and communities the clean air we deserve.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Janice E. Nolen

Commenter Affiliation: American Lung Association

Document Control Number: EPA-HQ-OAR-2002-0058-3679-A2

Comment Excerpt Number: 19

Comment: The American Lung Association supports the adoption of the safeguards against toxic air pollution from boilers and incinerators, as required under the Clean Air Act, to protect the public from life-threatening pollution and prevent tens of thousands of cases of illness and thousands of premature death each year. Curbing the different types of toxic pollution will yield tremendous benefits and significantly reduce adverse health effects.

The nation needs the EPA to adopt strong standards for toxic air pollution from boilers and incinerators to effectively protect the health of our communities. For over 20 years, the nation

has waited on EPA to set standards to clean up toxic pollutants as required in the Clean Air Act Amendments of 1990. The EPA has a historic and momentous opportunity to clean the air of notoriously harmful pollutants that endanger human health. Our organizations call on the EPA to adopt strong, final rules and give our families and communities the clean air we deserve.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Richard D. Garber

Commenter Affiliation: Boise Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3686-A2

Comment Excerpt Number: 8

Comment: Inadequate Time was Provided to Industrial Sources for Review and Comment on the December 23, 2011 Boiler MACT and Related Rules.

On December 23, 2011, the EPA published three notices proposing four new rules to reconsider and/or amend the March 21, 2011 final Boiler rules under the Clean Air Act (CAA) and the Resource Conservation and Recovery Act (RCRA): the major-source National Emission Standards for Hazardous Air Pollutants (NESHAPs) for industrial, commercial and institutional boilers and process heaters under CAA § 112 (Boiler rule); the area-source NESHAPs for industrial, commercial and institutional boilers under CAA § 112 (Area Source rule); and the New Source Performance Standards (NSPS) and emission guidelines for commercial and industrial solid waste incinerators under CAA § 129 and Non-hazardous Secondary Materials (NHSM) rule- under the RCRA defining "solid waste" to demarcate applicability under CAA § 112 and § 129 between boilers and solid waste incinerators (CISWI and NHSM rule).

As EPA is well aware, the proposed rules have raised an unprecedented number of complex issues in determining the appropriate MACT floors for these very large, diverse source categories. The simultaneous proposal of the rules greatly complicates the analysis of whether the standards can be achieved by affected sources. A large percentage of sources must first apply a complex set of factors under the NHSM rule to each material they combust, to determine whether EPA is likely to consider the material a waste or a fuel. If the materials would be considered *solid waste*, the source combusting those materials would be considered an *incinerator*, and it must then consider the applicability and achievability of the *CIS WI* standards. On the other hand, if under the NHSM rule, the materials are characterized as *fuel*, the source combusting those materials would be considered a *boiler*, and the source must then consider the applicability and potential achievability of the *Boiler rule* (for a major source) or *Area Source rule* (for a non-major source).

When EPA initially proposed these rules for comment on June 4, 2010, EPA provided for 60 days of comment. As multiple entities explained in letters to EPA at that time, 60 days is inadequate for sources to review voluminous data and EPA's analysis and to assess the achievability and impact of all four rules on the full range of affected sources at each facility.

In response to our request on the initial rule, EPA provided additional time for comments. Now on reconsideration, the rules are no less complex, EPA has added data that must be reviewed for 300 additional sources, and sources face the same pressures of sorting complex data and

developing thorough comments that address very technical issues. Although requesting a public hearing would have extended the comment period, we decided our time was better spent in developing comments. There is an extensive amount of data within the docket that takes many hours to sort through in order to produce thorough comments. Also, because EPA only allowed a few weeks, during the holidays, for review of the four proposals before the hearing would have been held, there was effectively less time to sort data in advance of a hearing. We were doubtful that we could have produced enough specific information to have a meaningful discussion by that date. For all these reasons, rather than use a procedural tool to achieve an extension, we decided to seek, in a straightforward fashion, additional time to prepare comments.

Understanding that EPA has made public commitments for an accelerated process to complete these rules, we only asked for 30 additional days for the Boiler MACT, CISWI and NHSM rules. We did not expect to need additional time for comment on the Area Source rule. EPA has an obligation to provide the public with a reasonable opportunity to comment on proposed rules. We have identified many issues with the proposed rules, but the lack of an extension has resulted in less time to fully develop our arguments and detailed justification for each of our comments.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Richard D. Garber

Commenter Affiliation: Boise Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3686-A2

Comment Excerpt Number: 9

Comment: We are very concerned that EPA is not leaving itself sufficient time to evaluate the substantive comments including new data, make appropriate revisions, and finalize within a couple of months after an important interagency review process. Cutting corners and rushing major rules such as these to the Federal Register greatly increases the chance of errors and oversights that would either make it vulnerable under court review or require further modifications after promulgation. That does not serve the public or the Agency well.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Dan F. Hunter

Commenter Affiliation: ConocoPhillips Company

Document Control Number: EPA-HQ-OAR-2002-0058-3689-A2

Comment Excerpt Number: 1

Comment: In §63.7485, you are subject to Subpart DDDDD if you own or operate an industrial, commercial, or institutional boiler or process heater that is located at a major source of HAPs, as defined in §63.2 or §63.761 (Subpart HH, NESHAPs from Oil and Natural Gas Production Facilities). This reference to another subpart, tying the definitions of "major source" together rather than incorporate the applicable regulatory text in each specific subpart, has created an unnecessarily complex situation; one where the result is revisions in one rule subsequently triggering the applicability of another; specifically, proposed changes to Subpart

HH will, if finalized, subject our facilities to Subpart DDDDD. In the case of Subpart DDDDD, EPA proposed significant revisions to requirements for both area and major sources. At the time, the definition of major source for oil and natural gas production facilities was not being proposed for revision. Therefore, owners/operators of oil and natural gas production facilities reviewed and provided comment based on their source status at the time (i.e., area sources reviewed the area source requirements and major sources reviewed and commented on the major source requirements). EPA did not provide any indication that they intended to propose a future change to the major source definition found in Subpart HH and there was no reason to foresee EPA would change such a critical definition that has been used since 1999 and is important for determining the area versus major source requirements for oil and natural gas production facilities. But EPA has not opened §63.7485 during this public comment period for the proposed rules. We thus find ourselves suddenly subject to a rule with which the applicability is closed to our comment. ConocoPhillips hopes EPA recognizes the procedural issues that have occurred as a result of the timing for each regulatory proposal and believes the proper remedy is for EPA to adopt the major source definition originally in DDDDD; i.e., copy the text of the §63.761 major source definition, prior to the proposed changes to that definition in 2011, into DDDDD. In addition, we request EPA's ongoing consideration of this concern with the regulatory structure in future rulemaking.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

100B. Exemption for All Gas-Fired Units [DENIED PETITIONER ISSUE]

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 40

Comment: We strongly support EPA's conclusion that the CAA 112(h) criteria are met and therefore design, equipment, work practice, or operational requirements are the appropriate and legal means of meeting the requirements of CAA section 112(d)(2) for D/F emissions, for the Gas 1 and Limited-Use subcategories and for smaller boilers and process heaters (i.e., <10 MMBTU/hr).

Response: The EPA thanks the commenters for their support.

100C. Natural Gas-Fired Water Heaters [DENIED PETITIONER ISSUE]

Commenter Name: Shannon S. Broome

Commenter Affiliation: Auto Industry Forum (AIF)

Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1

Comment Excerpt Number: 31

Comment: In its petition for reconsideration and subsequent comments, AIF asked EPA to reconsider the merits and disadvantages of imposing the work practice standard because

emissions from the units to which it applies are insignificant and to eliminate the biennial tune-up requirements for those units as well as for NG-fired hot water heaters with capacity greater than 120 U.S. gallons. AIF articulated that, contrary to EPA's claim that it lacks authority to exempt such units altogether from the final work practice standard, nothing in the cases on which EPA relied overruled *Alabama Power Co. v. Costle*, 636 F.2d 323, 400 (D.C. Cir. 1979), which clearly establishes EPA's authority to fashion *de minimis* and administrative necessity exemptions. AIF noted that EPA's approach of subjecting those small units to work practice standards, including biennial tune-ups, is extremely burdensome and costly without providing for corresponding, significant emission-reduction benefits. EPA's approach, AIF commented, would actually create incentives for facilities to switch from NG-fired water heaters to electric water heaters, which are far-less energy efficient. Therefore, AIF urged EPA to reconsider its decision not to exempt NG-fired boilers and large hot water heaters with heat input capacities of 10 MMBtu/hr or less from the infeasible and minimally beneficial work practice standards EPA promulgated. Consistent with that comment, AIF advocated for the elimination of biennial tune-up requirements on NG-fired hot water heaters with capacity greater than 120 U.S. gallons, given the extreme burdens imposed and the lack of emission-reduction benefits.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Shannon S. Broome

Commenter Affiliation: Auto Industry Forum (AIF)

Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1

Comment Excerpt Number: 32

Comment: *Under Alabama Power, EPA Appropriately Proposes to Change the Definition of "Hot Water Heater" to Include Those Combusting Gaseous or Liquid Fuel with a Heat Input Capacity of Less Than 1.6 MMBtu/hr.*

As noted above, the reconsideration proposal modifies the definition of "hot water heater" to include hot water boilers that combust gaseous or liquid fuel and that have a heat input capacity measuring less than 1.6 MMBtu/hr. Hot water heaters are not subject to the Boiler MACT, so EPA's proposal functions as a *de minimis* exemption for those types of hot water boilers. AIF supports the proposed change to the definition because the administrative (and economic) burdens of regulating those types of small, NG-fired hot water boilers – which include those hot water boilers for the showers that assembly workers use to clean up after their shifts – are excessively burdensome without a meaningful, corresponding benefit in terms of reducing HAP emissions. Given those factors, EPA clearly has the authority to finalize its proposal under *Alabama Power Co. v. Costle*, 636 F.2d 323, 360-61, 400 (D.C. Cir. 1979).²⁰ *Alabama Power's* essential holding relevant to this context is that agencies like EPA have the authority to issue *de minimis* exemptions as a rational approach for relieving severe administrative (and economic) burdens that blind adherence to the literal terms of a statute would otherwise create.²¹ *See* 636 F.2d at 360-61, 400.

Under *Alabama Power*, EPA has the inherent power to overlook trifling matters, such as the *de minimis* HAP emissions, to the extent such emissions are even measurable, from these types of small, NG-fired hot water boilers. *See id.* at 360-61. As the D.C. Circuit emphasized in *New York*

v. EPA, 444 F.3d 880, 888 (D.C. Cir. 2006), and as the U.S. Supreme Court held in *Wisc. Dep't of Rev. v. William Wrigley, Jr., Co.*, 505 U.S. 214, 231 (1992), the *de minimis* doctrine is a legal principal that forms part of the established background against which all statutes are enacted. Agencies, therefore, may diverge from the plain meaning of the statute as far as is necessary to avoid its futile application.²² See *New York*, 444 F.3d at 888.

[Footnote 20: Moreover, nothing in the statute compels EPA to regulate every possible emission point at a major source. *Alabama Power* simply provides additional justification for EPA's action here.]

[Footnote 21: EPA has indicated that it believes the literal terms of the statute compel it to regulate these sources. While AIF does not concede that the literal terms require regulation of these small units, to the extent they do, *Alabama Power's* *de minimis* authority still would be available.]

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Shannon S. Broome

Commenter Affiliation: Auto Industry Forum (AIF)

Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1

Comment Excerpt Number: 33

Comment: Section 112 "permits" *EPA* to issue this *de minimis* exemption. See *EDF v. EPA*, 82 F.3d 451, 466 (D.C. Cir. 1996). As the *EDF* court explained, the availability of a *de minimis* exemption depends on whether Congress has not been "extraordinarily rigid" in drafting a statute; if it has not, then there is an implication of the agency's authority to provide such an exemption, if "the burden of regulation yield[s] a gain of trivial or no value." *Id.* (quoting *Alabama Power*, 636 F.2d at 360-61) (internal quotation marks omitted).

Section 112 sets forth that EPA "shall publish, and shall from time to time, but no less often than every 8 years, revise ... a list of all categories and subcategories of major sources and area sources." CAA § 112(c)(1); 42 U.S.C. § 7412(c)(1). It then directs EPA to "establish emission standards under subsection (d)" as to those categories and subcategories. CAA § 112(c)(2); 42 U.S.C. § 7412(c)(2). Subsection (d) directs EPA to "promulgate regulations establishing emission standards for each category or subcategory of major sources and area sources of [HAPs] listed for regulation pursuant to subsection (c)." CAA § 112(d)(1); 42 U.S.C. § 7412(d)(1). Critically, it then proceeds to state the following:

Emissions standards promulgated under this subsection and applicable to new and existing sources of [HAPs] shall require the maximum degree of reduction in emissions of [HAPs] subject to this section (including a prohibition on emissions, where achievable) that the Administrator, taking into consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements, determines is achievable for new or existing sources in the category or subcategory to which such emission standard applies, through application of measures, processes, methods, systems or techniques ...

CAA § 112(d)(2); 42 U.S.C. § 7412(d)(2). The framework of this statutory scheme, then, permits EPA to define the units within the source categories and subcategories it is regulating in such a way as to exclude or exempt those units whose emission of HAPs is *de minimis*. This is because the CAA directs EPA to promulgate emission standards that require regulated sources to achieve a maximum degree of reduction in emission of HAPs but it expressly permits EPA to take into consideration the cost of achieving that reduction. It cannot be said that the statutory scheme is so extraordinarily rigid that it does not contemplate a potential *de minimis* exemption where the burden of regulation would yield a gain of trivial or no value, particularly considering “the cost of achieving such emission reduction.” CAA § 112(d)(2); 42 U.S.C. § 7412(d)(2).

The EDF decision supports the *de minimis* exemption for which AIF advocates because, there, the D.C. Circuit upheld EPA’s definition of the CAA’s prohibition of federal activities that do not conform to SIPs as exempting or excluding those federal activities that would produce either no or a trivial level of emissions. *See* 82 F.3d at 466. Beyond AIF’s arguments about the regulatory burden – on EPA, state agencies that must include the requirements in Title V permits and conduct enforcement of such requirements, and regulated entities that must comply with them – of including small, NG-fired hot water boilers within the scope of the Boiler MACT, therefore, there is a rational basis for EPA to find that HAPs from those units, to the extent such emissions are even measurable, are *de minimis*. As EPA has the authority to make that finding, it has the corresponding authority to finalize the proposed revision to the definition of “hot water heater” and AIF supports EPA finalizing that proposed revision.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

100D. Natural Gas and Oil Hot Water Systems Smaller than 10 MMBtu/hr [DENIED PETITIONER ISSUE]

Commenter Name: Shannon S. Broome

Commenter Affiliation: Auto Industry Forum (AIF)

Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1

Comment Excerpt Number: 34

Comment: *Alabama Power Also Supports a De Minimis Exemption for Small, Natural Gas-Fired Hot Water and Process Heaters with Heat Input Capacities of Up to 10 MMBtu/hr or Less.*

EPA should finalize a *de minimis* exemption from the Boiler MACT for small, NG-fired hot water and process heaters with heat input capacities of 10 MMBtu/hr or less. AIF recommends that EPA further change the definition of “hot water heater” to include any hot water boilers with heat input capacities of 10 MMBtu/hr or less and exclude from the definition of “process heater” any NG-fired process heaters with heat input capacities of 10 MMBtu/hr or less.

In its response to comments as to the proposed rule for the Boiler MACT final rule of March 21, 2011, EPA argued that it lacks the authority to issue a *de minimis* exemption as to emission standards established under Section 112. *See* Response to Comments on *Boiler MACT*, Vol. 1, at p. 339, Document Control No: EPA-HQ-OAR-2002-0058-3289. In making that argument, EPA

cited to the statutory language of Section 112(d) and case law from the D.C. Circuit that it described as requiring EPA to set emission standards for *all* HAP emitted from a source. EPA contended that this requirement precludes it from establishing a *de minimis* threshold below which HAP emitted by a source would not be regulated. EPA cited to the following cases:

- *Sierra Club v. EPA*, 479 F.3d 875, 883 (D.C. Cir. 2007) (“EPA has a ‘clear statutory obligation to set emission standards for each listed HAP,’ which does not allow it to ‘avoid setting standards for HAPs not controlled with technology.’” quoting *Nat’l Lime Ass’n v. EPA*, 233 F.3d 625, 634 (D.C. Cir. 2000) (“*Nat’l Lime II*”).
- *NRDC v. EPA*, 489 F.3d 1364, 1371 (D.C. Cir. 2007) (holding that EPA must establish emission standards for listed HAP emitted from a category, citing the *Sierra Club* and *Nat’l Lime II* decisions).

In its petition for reconsideration and subsequent comments, AIF pointed out that nothing in those cases overruled Judge Leventhal’s decision for the Court in *Alabama Power*, which, as described above, clearly establishes EPA’s authority to exempt *de minimis* situations and create exemptions based on administrative necessity. Had the Court intended to overrule *Alabama Power* in its subsequent decisions, it surely would have been more clearly. EPA fails to address this contention in the reconsideration proposal, instead merely stating that it disagrees with commenters that advocate for a *de minimis* exemption for small units. *See Boiler MACT Reconsideration Proposal*, 76 Fed. Reg. at 80,616.

As articulated above, the position previously argued by AIF was sound, and EPA failed to substantively respond to it in the reconsideration proposal. EPA has the authority to promulgate a *de minimis* exemption as to small hot water and process heaters, and any other source for which the burdens of regulation would be high and the emission-reduction benefits would be insignificant. This is not a context where the best performers use no emission control technology, *see Sierra Club*, 479 F.3d at 883; *Nat’l Lime*, 233 F.3d at 633, nor where the mechanism being advocated is EPA promulgating a risk-based subcategory, *see NRDC v. EPA*, 489 F.3d at 1368-71. Moreover, none of those cases disturbed or much less *considered* the essential holding of *Alabama Power*, *i.e.*, that agencies like EPA have the authority to issue *de minimis* exemptions as a rational approach for relieving severe administrative (and economic) burdens that blind adherence to the literal terms of a statute would otherwise create. *See* 636 F.2d at 360-61, 400. EPA appears to concede as correct AIF’s reading of the case law and EPA’s authority under the CAA in that it now proposes to change the definition of “hot water heaters” in a way that effectively creates a *de minimis* exemption for hot water boilers with heat input capacities of less than 1.6 MMBtu/hr.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Shannon S. Broome

Commenter Affiliation: Auto Industry Forum (AIF)

Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1

Comment Excerpt Number: 35

Comment: Accordingly, consistent with its authority under *Alabama Power*, EPA should finalize a *de minimis* exemption for small, NG-fired hot water and process heaters with heat input capacities of 10 MMBtu/hr or less. The work practice standards for these types of small and clean units, even with EPA's proposed reduction in tune-up frequency for certain units, remain infeasible from the standpoint of administration and cost, and provide minimal, if any, HAP emission reductions. In the experience of AIF members, tuning of NG-fired hot water and process heaters with heat input capacities of 10 MMBtu/hr or less has a limited effect on combustion efficiency, so the work practice standards only create additional burden without any corresponding, meaningful benefit in terms of HAP reductions.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Shannon S. Broome

Commenter Affiliation: Auto Industry Forum (AIF)

Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1

Comment Excerpt Number: 36

Comment: Providing support for the conclusion that a *de minimis* exemption is appropriate for these small units, one automotive facility currently spends an estimated \$40,000 annually to perform safety inspections on the various gas burners and gas trains in the facility. Almost all of these inspected burners are under 10 MMBtu/hr input and the vast majority of inspected units are between 1.6 and 5 MMBtu/hr. The facility projects that the additional cost for the tune-ups proposed in § 63.7540(10) could be of a similar magnitude. The present, annual cost of safety inspections does not include the myriad of small heaters less than 1.6 MMBtu/hr scattered throughout the plant as to which no inspections are currently required or performed. Without a *de minimis* exemption, many more of these small heaters would require tune-ups, which would further increase the cost impact on plant maintenance budgets with only a small reduction of HAP emissions.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Shannon S. Broome

Commenter Affiliation: Auto Industry Forum (AIF)

Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1

Comment Excerpt Number: 37

Comment: For example, a typical, well-tuned 10 MMBtu/hr burner emitting HAPs at the rate published in EPA's AP-42 NG emissions factor tables²³ would emit around 160 pounds of HAP per year. Even the most poorly-tuned unit of this size (which is unlikely to be encountered) could only emit HAPs at twice the rate of a well-tuned unit. A facility with twenty poorly-tuned 10 MMBtu/hr burners could collectively emit HAP at a rate of about 1.6 ton per year in excess of a well-tuned unit. Therefore, using the typical costs noted above, the cost of biennial inspections for such units would effectively cost at least \$12,500 per ton of HAP abated.²⁴ Similarly, inspections on a five-year schedule for twenty 10 MMBtu/hr burners would cost at least \$25,000 per ton abated. A hypothetical facility operating two 100 MMBtu/hr boilers and three 12

MMBtu/hr boilers, in addition to the twenty 10 MMBtu/hr burners in the example above, would be spending around 50% of its tune-up budget on the smallest units to minimize 8% of its HAP emissions due to biennial tune-up requirements. AIF believes that units are generally not "poorly tuned," so the cost per ton, in fact, will be dramatically higher than even estimated here.

[Footnote 23: U.S. EPA, *Compilation of Air Pollutant Emission Factors*, Table 1.4-3, "Emission Factors for Speciated Organic Compounds from Natural Gas Combustion," available at <http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s04.pdf>.]

[Footnote 24: If one assumes a more typical tuning profile, the cost per ton would be more akin to \$12,500 to \$25,000 per ton.]

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Shannon S. Broome

Commenter Affiliation: Auto Industry Forum (AIF)

Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1

Comment Excerpt Number: 38

Comment:

Moreover, because such units do not generally deteriorate over time in any meaningful way, EPA's approach, as articulated above, could actually increase emissions because it creates incentives for facilities to switch from NG-fired water heaters to electric water heaters, which are far-less energy efficient.²⁵ Facilities retaining their small NG-fired hot water and process heaters, which EPA has acknowledged sometimes number in the hundreds in a single facility, *see Boiler MACT Reconsideration Proposal*, 76 Fed. Reg. at 80,614, would face a large recordkeeping burden to track the compliance requirements and complete annual compliance certifications.

[Footnote 25: In part, the loss in energy efficiency would result from the electricity that would power those replacement electric heaters coming from coal-fired power plants, instead of from the NG supply that now powers the small units.]

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Shannon S. Broome

Commenter Affiliation: Auto Industry Forum (AIF)

Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1

Comment Excerpt Number: 39

Comment: And facilities would incur additional cost to account for such units as part of the Boiler MACT's one-time energy assessment, assuming EPA retains it in the final reconsideration rule.

These burdens would result from EPA's failure to promulgate a *de minimis* exemption because the majority of SIPs exclude these small units from permit-to-install regulations, *i.e.*, they are not presently listed in facilities' Title V permits due to their insignificance, and such units are, likewise, not covered by the scope of the industrial boiler NSPS, *see* 40 C.F.R. § 60.40c(a). There is no rational basis for EPA to not finalize the Boiler MACT consistent with those other regulatory programs. As the HAP emissions of small NG-fired hot water and process heaters with heat input capacities of 10 MMBtu/hr or less are insignificant and the consequent administrative burdens from subjecting them to the Boiler MACT are high, EPA should fashion a *de minimis* exemption to exclude them.²⁶ *See Alabama Power*, 636 F.2d at 360-61, 400.

[Footnote 26: To the extent that EPA decides not to fashion a *de minimis* exemption for NG-fired hot water and process heaters with heat input capacities of 10 MMBtu/hr or less, in the alternative, it should promulgate a *de minimis* exemption for such units at a cutoff of 5 MMBtu/hr or less, consistent with EPA's recognition of such a cutoff as the dividing line for less-frequent tune-ups in the reconsideration proposal. *See Boiler MACT Reconsideration Proposal*, 76 Fed.Reg. at 80,614. To the extent EPA does not promulgate such a *de minimis* exemption, in the alternative, it should issue a NG-fired *de minimis* exemption for NG-fired process heaters at the same cutoff of less than 1.6 MMBtu/hr it already proposed for hot water boilers. *See id.* at 80,652.]

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 13

Comment: CIBO sought reconsideration, of the definition of "hot water heaters," which are excluded from the Boiler MACT Rule. CIBO said "EPA should expand the definition to include natural gas or distillate fuel oil fired circulating hot water systems no larger than 10MMBtu/hr heat input that are used for domestic (e.g., washroom, cafeteria) or space heating purposes. This would eliminate the need to spend time or effort on units with insignificant emissions."

On Reconsideration, EPA defined hot water heater to include "Hot water boilers (i.e., not generating steam) combusting gaseous or liquid fuel with a heat input capacity of less than 1.6 million Btu per hour." 76 Fed. Reg. 80,652.

CIBO supports the revised definition and the the 1.6 MMBtu/hr limit on the definition EPA could exclude sources with larger capacities and still have no environ consequences..

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

100F. Blast Furnaces [DENIED PETITIONER ISSUE]

Commenter Name: Paul G. Page

Commenter Affiliation: AK Steel Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3457-A2

Comment Excerpt Number: 2

Comment: The Boiler MACT exempts blast furnace gas-fired boilers and process heaters with the qualification that the unit receives 90% or more of its total annual gas volume from blast furnace gas. AK Steel assumes that this qualification is based on an annual usage rate, but EPA has not specified that in the qualification language and needs to make clear how to determine the 90% threshold. AK Steel further assumes that units capable of qualifying for this exemption are expected to meet these criteria under normal operating conditions. However, blast furnaces periodically are shutdown for extended maintenance outages during which time blast furnace gas is unavailable and supplemental fuel must be used. AK Steel strongly supports the exemption, but we request clarifying language in the exemption to differentiate between periods of blast furnace gas curtailment and normal operations.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Paul G. Page

Commenter Affiliation: AK Steel Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3457-A2

Comment Excerpt Number: 3

Comment: Without clarifying language in the exemption, the 90% provision creates a compliance dilemma. One of our facilities currently uses fuel oil as a supplemental fuel for its blast furnace gas-fired boilers. Under normal operations, the facility can clearly demonstrate compliance with the 90% exemption qualification provision. However, AK Steel is concerned that if the facility is required to verify this "compliance status" with the exemption qualification on an annual basis, some given year could conceptually demonstrate that the facility does not qualify for the exemption. For example, if the blast furnace were to be shutdown for an extended maintenance outage or due to reduced customer demand, but the boilers were still needed for some minimal output such as comfort heating, then the exemption qualification demonstration may not be as certain as under normal operating conditions. Under this scenario even on an annual basis, the percentage of fuel oil usage would significantly increase and the percentage of blast furnace gas would significantly decrease. If the outage took place in January through March of the year, AK Steel would not know whether it met the exemption qualification until January of the following year and by that time normal operations would be in place. Assuming the facility did not meet the 90% exemption criteria for this hypothetical year, under the current proposed rule, the blast furnace gas-fired boilers would become liquid-fired boilers. However, it would not be possible for the facility to demonstrate compliance with the liquid-fired boiler requirements when they would be operating as blast furnace gas-fired boilers under normal process operations by the time the determination was made.

AK Steel believes that EPA simply overlooked this potential situation and does not intend to regulate blast furnace gas-fired boilers or process heaters under this scenario. Therefore, we encourage EPA to clarify the exemption criteria language for a blast furnace gas-fired boiler or process heater to stipulate that if it meets the 90 percent threshold during normal operations, then the unit will retain its status as a blast furnace gas-fired boiler independent of the volume of supplemental fuel it uses during periods of blast furnace gas curtailment. EPA should also take into consideration that it is to our economic advantage to use as much blast furnace gas as possible, whenever possible, and to minimize the use of supplemental fuel.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Peter Pagano

Commenter Affiliation: American Iron and Steel Institute (AISI)

Document Control Number: EPA-HQ-OAR-2002-0058-3490-A1

Comment Excerpt Number: 8

Comment: Once a boiler unit qualifies as a "Blast Furnace Gas Fuel Fired Boiler," that status should apply and not change even during times of blast furnace gas curtailment.

The Boiler MACT exempts blast furnace gas fuel- fired boilers and process heaters provided that the unit receives 90 percent or more of its total annual gas volume from blast furnace gas. Units capable of qualifying for this exemption must meet these criteria under normal operating conditions. However, for various operating reasons, iron and steel plants are susceptible to blast furnace gas curtailment periods, during which time sufficient blast furnace gas is not available to produce the plant's required steam or electricity normally generated by the blast furnace gas-fired boilers, and supplemental fuel must be used. AISI strongly supports the exemption, but we request clarifying language on the distinction between periods of blast furnace gas curtailment and normal operations.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Peter Pagano

Commenter Affiliation: American Iron and Steel Institute (AISI)

Document Control Number: EPA-HQ-OAR-2002-0058-3490-A1

Comment Excerpt Number: 9

Comment: The 90 percent provision creates a compliance conundrum. For example, blast furnace gas-fired boilers may use fuel oil as a supplemental fuel. Because the current Reconsidered Rule only contemplates backward-looking qualifications, iron and steel facilities must determine at the end of the year whether a unit used blast-furnace gas 90 percent of the time on average, inclusive of blast furnace gas curtailment periods. If a unit did not meet the criteria as determined after the fact, it is impossible to retroactively demonstrate compliance with the liquid-fuel requirements after the unit was operated as a blast-furnace gas boiler. We, therefore, seek clarifying language that if a unit qualifies as a blast furnace gas fuel-fired boiler or process heater because it meets the 90 percent provision during normal operations, it should be able to

retain its status as a blast furnace gas fuel-fired boiler even if it uses a supplemental fuel during periods of blast furnace gas curtailment.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

100G. Exhaust Used in Direct-Fired Process Heaters [DENIED PETITIONER ISSUE]

Commenter Name: Traylor Champion

Commenter Affiliation: Georgia-Pacific LLC (GP)

Document Control Number: EPA-HQ-OAR-2002-0058-3465-A1

Comment Excerpt Number: 23

Comment: Since these integrated systems serve multiple purposes, this gives rise to the potential regulatory applicability question as to whether operation of these systems results in the indirectly-heated portion of the drying system and the thermal oil system exhaust being subject to the requirements of the Boiler MACT rule as a process heater in addition to the PCWP MACT requirements. The pollutants generated from the drying process and the pollutants generated from the combustion process are part of the same exhaust stream which is ultimately exhausted to the atmosphere at a single location. Since integrated wood-fired heat sources which also provide a relatively small amount of indirect heat to a thermal oil heater or boiler are relatively common in the composite wood products manufacturing industry, this issue was anticipated during the rulemaking process for both the PCWP and the vacated Boiler MACT rules.

Accordingly, the term *Process Heater* as proposed in the current Boiler MACT rule is defined as “an enclosed device using controlled flame, and the unit’s primary purpose (*emphasis added*) is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material for use in a process unit, instead of generating steam. Process heaters include units heating hot water as a process heat transfer medium. Process heaters are devices in which combustion gases do not come into direct contact with process materials.” The combustion gases involved in indirect heat transfer for the more typical integrated heat sources are routinely re-combined with the heat source exhaust and direct-fired into the drying process where they come into direct contact with the process materials, so their exclusion from the definition is very clear. For the two GP facilities, however, the fact that a portion of the hot air to the drying process is indirectly heated and the fact that the exhausts from the indirectly heated hot oil units are not sent through the drying system has resulted in some confusion over their appropriate categorization. As noted above, the Wellons Energy System combustion gases at these facilities normally come in direct contact with the rotary strand dryers’ process materials (process exhaust gases from the drying process). Accordingly, their design, function, and emission characteristics are vastly different from boilers or process heaters as defined under the Boiler MACT rule. As such, we believe these units are more appropriately covered under the PCWP MACT given that their primary purpose is to support the operations that are covered under that rule in both serving as the heat source required for the drying process and as the control device for the pollutants generated in the drying process.

The applicability determination for the two GP units would be made less complicated if EPA incorporated the statement contained in the preamble into the proposed rule definition of a process heater. In the statement, EPA states that in this proposed rule, “process heaters are defined as units in which the combustion gases do not directly come into contact with process material or gases in the combustion chamber (e.g. indirect fired)”. However the definition only contains the term “process material” but does not include the term “gases” which should be added to the definition. With this change, it would be clear that these systems’ incorporation of all the drying process gases into the integrated wood-fired heat source prevented their classification as “process heaters”. Furthermore, since all pollutants generated from these operations are exhausted to the atmosphere via a single location under normal operations, it would be impossible to segregate the pollutants generated from the source that could potentially be subject to Boiler MACT requirements from the sources that are covered under PCWP MACT requirements. Additionally based on the above-described facility-specific operational conditions at these facilities, GP has already addressed the operation of these integrated systems as part of the overall PCWP MACT compliance program. [See submittal for process flow diagram]

GP urges EPA to:

- b. Include in the preamble to the final rule a determination that Wellons Energy Systems are clearly regulated under the PCWP MACT and not under Boiler MACT, as discussed above.
- c. Revise the proposed definition of process heater in §63.7575 to include the preamble language of “gases” as discussed above. The revised definition should read as follows:

“Process heater means an enclosed device using controlled flame, and the unit’s primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material for use in a process unit, instead of generating steam. Process heaters include units heating hot water as a process heat transfer medium. Process heaters are devices in which combustion gases do not come into direct contact with process materials or contain process exhaust gases.”

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

MACT Floor Analysis

3A. MACT Floor Methodology: Statistical Procedure for CO

Commenter Name: John M. Cullen

Commenter Affiliation: Masco Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3661-A2

Comment Excerpt Number: 4

Comment: EPA proposes to use a 99% upper prediction limit (“UPL”) for CO MACT floor analysis. Masco disagrees with EPA’s decision to use a 99% percent confidence interval versus a 99.9% interval as original proposed. Carbon monoxide emissions have a high degree of variability by comparison to other pollutants and a source is compelled to certify compliance

with the CO limit over all operating conditions except startup and shutdown. EPA's CO MACT floor should account for such variability to the extent reasonably possible. Masco submits that the rationale for the 99.9% confidence interval in the March 21, 2011 Boiler MACT rule remains valid.

Response: For the reasons outlined in the preamble to the December 23, 2011 proposed reconsideration of the rule (See 76 FR 80614), EPA has elected to retain the 99% UPL in its calculation of emissions variability for all subcategories. In addition, EPA is establishing alternative CO limits for those subcategories for which EPA has sufficient data to establish such limits.

Commenter Name: M.L. Steele

Commenter Affiliation: CraftMaster Manufacturing, Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3814-A1

Comment Excerpt Number: 8

Comment: In its data variability analysis USEPA lowered the CO confidence coefficient from 99.9% to 99% to be consistent with other pollutants. CraftMaster's 15 years of experience with CO GEM's on a biomass-fired unit indicates that the variability of CO is not like other pollutants and we believe the higher confidence coefficient for CO is justified. CO emissions can vary significantly and quickly due to load swings and changes in fuel characteristics such as moisture content, bulk density, etc.

Response: See the response to EPA-HQ-OAR-2002-0058-3661-A2, excerpt 4.

Commenter Name: Ashok K. Jain

Commenter Affiliation: National Council for Air and Stream Improvement, Inc. (NCASI)

Document Control Number: EPA-HQ-OAR-2002-0058-3505-A1

Comment Excerpt Number: 19

Comment: In the recent MACT Floor memo (ERG 2011b), the revised floor analysis included an important difference from the analysis conducted for the March 2011 final Boiler MACT rule. The revised memorandum stated "Statistical variability was incorporated using the 99% UPL for CO (a change from the 99.9% UPL that was used for CO in the final rule), in order to be consistent with the UPL statistic selected for the other regulated pollutants." In the final rule preamble, EPA concluded "In this final rule, we have determined that 99 percent UPL is appropriate for fuel based HAP and a 99.9 percent UPL is appropriate for combustion dependent HAP (i.e., CO)." Also, "For CO, EPA considered both quantitative and qualitative comments received during the public comment period on how CO emissions vary with load, fuel mixes and other routine operating conditions. After considering these comments EPA determined that a 99.9 percent confidence level for CO would better account for some of these fluctuations." The significantly higher variability associated with emissions of CO from an industrial boiler as compared to HCl, Hg, filterable particulate matter, and total selected metals is well documented, and a higher level of confidence limit assigned to the UPL for CO is appropriate. The need to be consistent with the UPL statistic for the other regulated pollutants is not relevant. In cases where additional Method 10 tests were obtained for boilers already identified as best performers, the variability among tests and test runs was seen to be very large. Furthermore, analysis of CO

CEMS data confirm that a limit based on the 99% UPL does not adequately reflect variability in CO emissions even during periods of steady operation at relatively high loads. NCASI firmly believes that UPLs with 99.9% confidence limits are necessary and appropriate to address the documented variability of CO emissions from industrial boilers, especially boilers burning biomass fuels.

Response: For a response to the claim that a 99.9% confidence interval is preferred over a 99% confidence interval for CO emissions due to inherent variability, see comment EPA-HQ-OAR-2002-0058-3661-A2, excerpt 4. The EPA disagrees that the need to be consistent with confidence intervals for the other regulated pollutants is irrelevant because emission limits for all pollutants must be met simultaneously; identical confidence intervals between pollutants does not allow the emission limits for any of the regulated pollutants to take precedence over the others.

The commenter did not provide the analysis conducted on CO CEMS data based on a 99% UPL, thus EPA cannot respond to the claim that the 99% UPL does not adequately reflect variability in CO emissions even during periods of steady operation at relatively high loads.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 72

Comment: Selection Of Confidence Level For CO

EPA is proposing to revise the CO MACT floor analysis to use a 99 percent confidence interval as opposed to a 99.9 percent confidence interval to determine the UPL.

ACC does not agree with EPA's justification in using a 99 percent confidence interval "for consistency's sake." Carbon monoxide emissions have a much greater degree of variability than other pollutants, and EPA is requiring sources to certify compliance with the CO limit under all operating conditions except startup and shutdown. Therefore, EPA's CO MACT floor should account for variability to the maximum extent possible. The small amount of data used in EPA's analysis is not representative of the range of expected operations and true variability that is expected from the best performers. The emissions data used to set the CO limit is based on stack testing performed during maximum load conditions, only providing a snapshot of the day-to-day operations of each source.

EPA cited several reasons why it used a 99.9 UPL to set the CO MACT floor in the preamble to the Final Boiler Rule, including fuel moisture content after a rain event, elevated moisture in the air, and fuel feed issues or inconsistency in the fuel. (76 Fed. Reg. 15628.) The reasons are still valid now, and therefore, EPA should retain the use of the 99.9 UPL for calculating CO limits in its reconsidered final rule.

Response: For a response to the claim that the same confidence interval is not required for all regulated pollutants, please see EPA-HQ-OAR-2002-0058-3505-A1, excerpt 19. For a response to the claim that a 99.9% confidence interval is a better choice to account for inherent variability of CO emissions, please see comment EPA-HQ-OAR-2002-0058-3661-A2, excerpt 4. EPA

acknowledges that emissions of CO are inherently more variable than emissions of the other regulated pollutants, but EPA also believes that the 99% UPL appropriately accounts for the variability in emissions of all of the regulated pollutants.

Commenter Name: Shannon S. Broome

Commenter Affiliation: Auto Industry Forum (AIF)

Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1

Comment Excerpt Number: 5

Comment: EPA is proposing to revise the CO MACT floor analysis to use a 99 percent confidence interval as opposed to a 99.9 percent confidence interval to determine the UPL. We do not agree with EPA's rationale for reverting to a 99 percent confidence interval. EPA states (76 Fed. Reg. 80614).

We do not agree with the justification to use a 99 percent confidence interval for consistency's sake. Carbon monoxide emissions have a much greater degree of variability than other pollutants and a source must certify compliance with the CO limit over all operating conditions except startup and shutdown; therefore, EPA's CO MACT floor should account for variability to the maximum extent possible. The small amount of data used in EPA's analysis is not representative of the range of expected operations and true variability that is expected from the best performers. The emissions data used to set the CO limit are based on stack testing performed during maximum load conditions, only providing a snapshot of the day-to-day operations of each source.

The reasons for using a 99.9 UPL for setting the CO MACT floor cited in the preamble to the March 2011 Boiler MACT rule remain valid: *76 Fed. Reg. 15628*. Therefore, EPA should retain the use of the 99.9 percent UPL for calculating CO limits.

Response: For a response to the claim that the same confidence interval is not required for all regulated pollutants, please see comment EPA-HQ-OAR-2002-0058-3505-A1, excerpt 19. For a response to the claim that a 99.9% confidence interval is a better choice to account for inherent variability of CO emissions, please see comment EPA-HQ-OAR-2002-0058-3661-A2, excerpt 4.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 40

Comment: EPA is proposing to revise the CO MACT floor analysis to use a 99 percent confidence interval as opposed to a 99.9 percent confidence interval to determine the UPL. We do not agree with EPA's rationale for reverting to a 99 percent confidence interval. EPA states (76 FR 80614).

We do not agree with the justification to use a 99 percent confidence interval for consistency's sake. Carbon monoxide emissions have a much greater degree of variability than other pollutants and sources must certify compliance with the CO limit overall operating conditions except startup and shutdown; therefore, EPA's CO MACT floor should account for variability to the

maximum extent possible. The small amount of data used in EPA's analysis are not representative of the range of expected operations and true variability that is expected from the best performers. The emissions data used to set the CO limit is based on stack testing performed during maximum load conditions, only providing a snapshot of the day-to-day operations of each source.

The reasons for using a 99.9 UPL for setting the CO MACT floor cited in the preamble to the March 2011 Boiler MACT rule remain valid. Therefore, EPA should retain the use of the 99.9 UPL for calculating CO limits.

Response: For a response to the claim that the same confidence interval is not required for all regulated pollutants, please see comment EPA-HQ-OAR-2002-0058-3505-A1, excerpt 19. For a response to the claim that a 99.9% confidence interval is a better choice to account for inherent variability of CO emissions, please see comment EPA-HQ-OAR-2002-0058-3661-A2, excerpt 4.

Commenter Name: Michael L. Krancer

Commenter Affiliation: Pennsylvania Department of Environmental Protection (DEP)

Document Control Number: EPA-HQ-OAR-2002-0058-3507-A1

Comment Excerpt Number: 13

Comment: In the final rule, the EPA selected the use of a 99.9 percent confidence interval for calculating the MACT floor for CO emissions, which was challenged by a petitioner requesting reconsideration of this selection given the fact that the EPA used a 99 percent confidence interval for all of the other emission limits in the final rule. The petitioner pointed out that if the data are highly variable, the 99 percent confidence interval should adequately reflect the variability of emissions (e.g. variability during startup and shutdown events) as well as for the data sets of the other pollutants. Therefore, EPA has proposed to use a 99 percent confidence level for CO in order to maintain a consistent methodology in the development of the MACT floors for other pollutants, and because optional CO CEMS-based limits have also been proposed that would allow sources additional flexibility in meeting the requirements of the proposed rule.

The DEP believes that it is important to be consistent in the development of the MACT floors for all of the pollutants and therefore agrees with the EPA for using the same 99 percent confidence level in setting the CO emission limit.

Response: EPA appreciates the commenter's support for the use of the 99% UPL. For a response to the claim that the same confidence interval is not required for all regulated pollutants, please see comment EPA-HQ-OAR-2002-0058-3505-A1, excerpt 19. For a response to the claim that a 99.9% confidence interval is a better choice to account for inherent variability of CO emissions, please see comment EPA-HQ-OAR-2002-0058-3661-A2, excerpt 4.

Commenter Name: Randall D. Quintrell

Commenter Affiliation: Georgia Paper & Forest Products Association

Document Control Number: EPA-HQ-OAR-2002-0058-3451-A1

Comment Excerpt Number: 8

Comment: The proposed CO limits continue to ignore the reality of CO control among the diverse universe of boilers being regulated, even with subcategorization; the documented limited benefit of CO control below a threshold of 300 ppmv (provided in other's comments) for control of organic HAP; and the adverse affects of operating a unit to minimize CO to low levels, which for example include increased NOx emissions and lower boiler efficiency, requiring increased fuel use for the same output. The proposed limits should be adjusted to reflect the true boiler operating variability, particularly with load following units; and the inverse relationship with nitrogen oxides, a pollutant of high concern. For some subcategories, the CO limits proposed remain unachievable, in large part because EPA has not taken into account the true variability of even the best performing units and has proposed using a 99 percent confidence interval instead of 99.9% on one of the most highly variable emissions, one that is a surrogate and is not even a HAP. EPA should revert to its position in the preamble to the March 2011 rule in this regard, and maintain the 99.9% UPL, and it should not require CO limits less than 300 ppmv as a surrogate for HAP control for any boiler units.

Response: EPA acknowledges the relationship between CO and NOx emissions. In its calculation of CO MACT floor emission limits, EPA investigated the relationship between reported CO and NOx emissions for each of the top performing units. Certain CO tests were disqualified from MACT floor calculations on the premise of high NOx emissions. Further detail on the relationship between CO and NOx and how it affected the CO emission limitations can be found in the memo entitled, "Revised MACT Floor Analysis for the Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP" in the docket.

EPA disagrees with setting CO emission limitations no lower than 300 ppmv given the volume of reported CO emissions testing and continuous emissions monitoring data reported below this threshold. In addition, preliminary data from surrogacy testing conducted at EPA's Multi-pollutant Control Research Facility show a downward trend in PAH emissions with decreasing CO emissions below 300 ppm. A presentation entitled "Hazardous Air Pollutant (HAP) Emissions Testing in the EPA Pilot-Scale Combustion Research Facility" which presents this preliminary data can be found in the docket.

For a response to the claim that a 99.9% confidence interval is a better choice to account for inherent variability of CO emissions than a 99% confidence interval, please see comment EPA-HQ-OAR-2002-0058-3661-A2, excerpt 4.

Commenter Name: Douglas A. McWilliams

Commenter Affiliation: American Municipal Power

Document Control Number: EPA-HQ-OAR-2002-0058-3685-A2

Comment Excerpt Number: 26

Comment: EPA's MACT Floor Methodology is Flawed

AMP has expressed concern with EPA's MACT floor methodology in its previous comments, and suggested ways EPA could remedy those issues to calculate MACT floors that are both achievable and supportable. EPA has failed to take steps within its discretion to help set achievable emission limits that can be met by all units subject to this rulemaking- including small municipal utilities. AMP asks that EPA take this final opportunity to rectify the persistent

flaws in its MACT floor methodology and adopt *achievable* emission limits as the Clean Air Act requires.

Response: The methodology for establishing the MACT floor is outside the scope of this reconsideration with the exception of a few discrete items related to the methodology that EPA specifically requested comment on in its December 23, 2011 proposal. EPA solicited and responded to comments regarding the statistical analysis used to develop the alternative CO CEMS-based emission limitations. Please see the responses to those comments, as well as the memo titled, "CO CEMS MACT Floor Analysis (May 2012) for the Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP" in the docket for discussion on the changes in methodology for the alternative CO CEMS-based emission limits. For discussion on the request for a 99.9% UPL in lieu of a 99% UPL, please see comment EPA-HQ-OAR-2002-0058-3661-A2, excerpt 4.

Commenter Name: Ashok K. Jain

Commenter Affiliation: National Council for Air and Stream Improvement, Inc. (NCASI)

Document Control Number: EPA-HQ-OAR-2002-0058-3505-A1

Comment Excerpt Number: 25

Comment: Some boilers determined by EPA to be best performers for CO based on 3 one hour average stack test runs were also equipped with CEMs for CO, either permanently as in the case of the biomass FBC units at GATemple InlandRome and ALIPCourtland, or temporarily as in the case of the biomass stoker unit at MSGPNewAugusta. An analysis of the hourly average CEM data for these units shows that several three hour block averages would have exceeded the currently proposed 3 hour average 99% UPL limits of 370 ppm for biomass FBCs and 790 ppm for biomass stokers at 3% O₂. Thus even a best performing boiler is likely to have some 3-hour average CO concentrations above a 99% UPL value.

Response: The alternative CO CEMS-based limits referenced by the commenter are ten day rolling averages and not three hour block averages. The ten day averaging period is designed to address concerns regarding variability such as that in this comment.

3B. MACT Floor Methodology: Non-Continental Liquid

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 63

Comment: Since the non-continental liquids subcategory has less than 30 units, the PM emission limitation must be calculated based on the procedures typical of such subcategories.

The proposal establishes a numerical emission limit for filterable PM of 0.0080 lb per MMBTU of heat input for new, reconstructed, and existing BPH. These limits were established based on data provided by non-continental sources since the March 21, 2011 rule was promulgated using the EPA's paradigm for subcategories that contain more than 30 units.

However, with the shutdown of the HOVENSA refinery in February 2012²³, this subcategory contains less than 30 units and the normal EPA approach to establishing a limit for such a subcategory is to use the average of the available test data and then adjust statistically for variability. The test data for this subcategory confirms there is considerable variability between non-continental BPH, which reflects the differences in the fuels such units must feed (i.e., fuels produced in their own refining operations) and the different burner designs that result from having to have the capability to burn both liquid and gaseous fuels. The Tesoro boiler can burn either liquid or gaseous fuels, but not at the same time; while the Chevron process heater can fire both liquid and gaseous fuels in the same burners at the same time. The Tesoro boiler also uses burners that were designed to minimize opacity while the Chevron source has newer burners designed to minimize NO_x formation. Therefore, there are important technical differences that account for some of the observed variability in the available test results. It is critical that the variability reflected in the test reports be appropriately addressed in developing the PM limitation for the less than 30 unit non-continental liquids subcategory.

Applying the same approach to variability to these non-continental liquid subcategory units as was done for the continental liquids subcategory, and as described in ERG's floor memo results in a calculated upper prediction limit (UPL) of 0.36 lb per MMBTU of heat input at a 99% confidence level. The calculation of these recommendations is shown in Attachment 1 [see submittal for Attachment 1. PM Variability Calculations] in the same format used by EPA in the floor analysis for other <30 unit subcategories. Basing the PM standard on this calculated UPL is a reasonable approach for EPA to use in addressing the variability of PM emissions from these specific units. The reasonableness of this PM limit is supported by a recent Chevron test result of 0.22 lb/MMBTU (Attachment 3) [see DCN EPA-HQ-OAR-2002-0058-3677-A3 Attachment 3. Chevron, Kapolei, Hawaii, PM Boiler Stack Test Results]. Although the recent Chevron test was done for operation information purposes and was not an official test, the results support the reasonable outcome of this EPA variability calculation procedure.

[Footnote 23: On Wednesday, January 18, 2012, HOVENSA announced its refinery will be shutting down operations over the next 3 week period. HOVENSA will continue to operate the marine terminal as an oil/product storage and distribution facility. All refinery specific processing units will be shutdown. As a 525,000bpd facility, HOVENSA operated 23 oil-burning heaters and boilers. As an oil/product storage and distribution facility HOVENSA will most likely operate one boiler which could potentially burn oil.]

Response: EPA acknowledges that the HOVENSA refinery in St. Croix has shut down, and the inventory of major source industrial, commercial, and institutional boilers and process heaters has been updated accordingly. With the closure of this facility, EPA agrees that there are less than 30 applicable boilers or process heaters designed to burn liquid fuels located in non-continental states or territories. The 99% UPL for all regulated pollutants for the non-continental liquid units have been recalculated based on the reduced number of units in the subcategory, and following the procedures outlined in the memorandum titled "MACT Floor Analysis for the Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP - Major Source" located in the docket. The recalculated UPLs incorporate all additional emissions testing data provided to EPA during the comment period.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 66

Comment: Since the non-continental liquids subcategory has less than 30 units, the CO emission limitation must be calculated based on the procedures typical of such subcategories.

As noted previously, the non-continental liquids subcategory will have less than 30 units. Thus in accordance with Section 112(d)(3)(B) of the CAA, the CO standard for existing sources should be based on the best performing 5 sources for which the Administrator has emissions information. Consistent with ERG's MACT floor memo and its CO measurement error memo, the calculated 99% UPL for CO based on all of the individual runs for the top performing three sources with CO stack test data available (Chevron's F-5103 and Tesoro's SG1102 and SG1103) results in approximately 140 ppm CO at 3% O₂. The calculation of these recommendations is shown in Attachment 2 [see DCN EPA-HQ-OAR-2002-0058-3677-A4 CO Variability Calculation] in the same format used by EPA in the floor analysis for other <30 unit subcategories.

Response: For a response to the comment that, due to the closure of the HOVENSA refinery in St. Croix, there are now fewer than 30 non-continental liquid units and MACT Floors should be adjusted accordingly, see comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 63.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 64

Comment: The top ranked BPH used in establishing the PM emission limits for this subcategory is the Tesoro boiler SG-1102. However, the test data for that unit was obtained with the unit operating at 40% of load (representative of typical operations for that particular boiler). Operation at low load does not provide PM results that represent the high rate operation that is the usual basis for performance tests and that is typical for other BPH in the subcategory. Low load operation results in increased residence time as compared to full load operations and could result in lower PM_{2.5}. Coen Company, a major burner manufacturer, has provided the following graph [see submittal graph of Boiler PM Emission Factors vs. Load %] 26 illustrating the significant impact of load. The chart uses data from one boiler on the East Coast firing heavy fuel oil that has 2% Sulfur, 0.15% Ash, and 5% Asphaltene. The PM was measured by EPA test method 5 with filter box at 250°F.

In consideration of the best performing source for establishing the PM standard for new sources in the non-continental liquid subcategory, it is important to note that the fuel for the top ranked unit (Tesoro's SG-1102) is specific to the Tesoro refinery and cannot be reasonably purchased or obtained by other sources in the subcategory. In addition, this test was performed at 40% of maximum load and, as discussed above, such operation could result in PM emissions less than

expected at higher loads. Consistent with the HCl MACT floor for new boilers designed to burn liquid fuel, the Hg MACT floor for new boilers designed to burn solid fuel, and the CO MACT floor for new fluidized bed boilers designed to burn biomass, and as described in ERG's previously-cited memo (page 24), we request that EPA utilize the next lowest emissions as the basis for the floor calculations. Using the second lowest test average for the PM MACT floor for new non-continental liquid BPH results in 0.078 lb per MMBTU, based on the calculated 99% UPL. The calculation of these recommendations is shown in Attachment 1 [see DCN EPA-HQ-OAR-2002-0058-3677-A3 Attachment 1. PM Variability Calculation] in the same format used by EPA in the floor analysis for other <30 unit subcategories.

[Footnote 25: The carbon burnout mechanism from oil combustion is very complex. In general, the carbon loss is strongly influenced by furnace residence time. For example, the furnace may be designed for 0.5 seconds residence time at maximum firing conditions. When this furnace is operating at 50% of maximum load, the residence time would be almost doubled. This enables carbon particles to spend more time in hot zone and help burn better.]

[Footnote 26: Private communication (E-Mail), Vijay Mandayam, Director, Combustion System Group, Coen Company, Inc. to Clay Freeberg, Chevron Corporation, February 1, 2012.]

Response: EPA disagrees that the low-load PM emissions testing data should be disregarded. Emissions from low load operations are incorporated in the MACT floor analysis for multiple subcategories (for example, Suspension Burners designed to combust biomass/bio-based solids). EPA also disagrees that the test should be disregarded on the premise of site-specific fuel; several facilities located in non-continental states or territories combust site-specific fuel, and disregarding tests combusting site-specific liquid fuel for all applicable non-continental boilers would minimize the available emissions testing data for the subcategory. EPA has incorporated the additional emissions testing data submitted by Tesoro for the top performer. The variability between the previously reported and new emissions testing data have resulted in a less stringent PM emission limitation for boilers designed to combust liquid fuel located in non-continental states or territories.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 68

Comment: Test data from Tesoro's SG1102 may not represent the CO emissions achieved in practice for other non-continental liquids subcategory BPH. In addition to the performance test being conducted on the unit at 40% load, the fuel consumed during the test is specific to the Tesoro refinery and cannot be reasonably used by other sources in the subcategory. As such, we request that EPA utilize the next best source to determine the CO floor for new sources, or Chevron's F-5103 unit, which results in a new source standard of 51 ppm CO at 3% O₂. The calculation of these recommendations is shown in Attachment 2 [see DCN EPA-HQ-OAR-2002-0058-3677-A4 Attachment 2] in the same format used by EPA in the floor analysis for other <30 unit subcategories.

Response: For a response to the comment that Tesoro's boiler SG1102 test data are not representative of other non-continental liquid units due to low-load operation and site-specific fuel, please see comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 64. EPA has incorporated additional CO emissions testing data for the top performer into the recalculation of the 99% UPL for the subcategory. The variability between the previously reported and new emissions testing data resulted in an increased CO emission limitation for boilers designed to combust liquid fuel located in non-continental states or territories.

3C. MACT Floor Methodology: Non-Detect Values

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 14

Comment: EPA exacerbated these problems with the approach to “non-detect” test results that it took in 2010. That approach continues to be unlawful and arbitrary for all the reasons given in the 2010 comments, which are incorporated by reference as if fully stated herein and reiterated with respect to the agency’s 2011 final rule and reconsideration proposal. 2010 Comments at 22.

Now, EPA further exacerbates the other flaws in its variability analysis by arbitrarily assuming that individual sources’ actual emission level are three times higher (*i.e.*, worse) than an arbitrarily selected “method detection level”(MDL) whenever their emissions fell below this level. That bizarre assumption follows a series of decisions that were unlawful, arbitrary, or both. First, EPA itself encouraged sources to report tests below method detection levels by advising them during the data collection phase that they did not need to use specific (or even adequate) criteria for testing and assuring them that the agency would address the absence of precise data in its rulemaking. As a result of EPA’s stated willingness to accept data that were not precise, many sources used testing methods that were not precise and that yielded non-detect results at emission levels that could have been precisely measured had these sources chosen to use more precise testing methods – which are available and have been available for many years. Second, EPA now claims that any test below the mean detection level for all the alleged best sources in every subcategory – a level the agency now dubs the “representative detection level” or “RDL” – is a non-detect, whether that test really is a non-detect or not. Third, for all of the alleged non-detect results, EPA simply fills in a fictional replacement value equal to 300% of the RDL, unless that number would be lower than the floor. Nowhere does the agency offer any explanation for its apparent assumption that the 99% UPL it applies to each source’s emission test results does not already fully account for that source’s variability. Further EPA uses this 300% multiplier even though it does not and cannot provide any rational basis for assuming that all test results below the RDL actually reflect emission levels 300% higher than the RDL (even assuming *arguendo* that that they are higher than the RDL at all). All the agency offers on that subject is a conclusory assertion that multiplying the RDL by three approximates a 99% UPL for a data set of seven or more values, without either supporting that claim or explaining why it is even relevant. For these reasons alone, EPA’s floors do not reflect the best sources’ actual emission levels and are unlawful and arbitrary. Moreover, it is arbitrary – and amounts to a sabotage of the rule – for EPA to encourage sources to submit imprecise emissions data and then

use the resulting imprecision in the data it receives as an excuse to grossly inflate the emission standards.

Response: The commenter is incorrect that EPA's test method specifications during the ICR data collection encouraged the collection of data below the detection level. During the data collection request, we specified sampling times and/or volumes where appropriate. These times/volumes were calculated to provide reasonable assurance of detecting compounds that were present. EPA manual testing methods are designed to be conducted over an hour of sampling, but may be conducted with extended testing times to collect additional sample volume and provide for increased measurement sensitivity. Our guidance to ICR respondents for reporting pollutant emissions used to support floor development has been to require them to provide test-specific method detection limit (MDL) values in the reports. Also, in accordance with our guidance, source owners are to identify emissions data which were measured below the MDL and report those values as equal to the MDL determined for that test. This is done to provide for minimum pollutant concentrations when evaluating the emission floor, otherwise the measured concentration values as reported in the testing were used in calculating the floor.

Not all test reports that include instrumental test method data included test-specific MDL values. In cases where the report does not include test-specific MDL data measured with an instrumental test method, the test-specific MDL values were determined using the reported calibration span values. The EPA accounted for the effect of measurement imprecision in calculating a floor using a database that includes reported MDL data by first defining an MDL value that is representative of the data to be used in establishing the floor or emissions limit. This value is termed the representative method detection limit (RDL). The second step in the process was to calculate three times the RDL and compare that value to the calculated floor or emissions limit. The value of 3* RDL is necessary to gauge the performance test methods' level of quantitation, or that point at which the test method begins to return values within expected levels of confidence. The EPA recognizes that values between the method detection limit and the level of quantitation have more uncertainty than values at or above the level of quantitation, therefore we make this determination to provide a value to the floor setting decision process that describes the level of quantitation for the compliance determination method. If 3*RDL was less than the calculated floor or emissions limit calculated from the upper prediction limit (UPL), we concluded that measurement variability was adequately addressed and the calculated floor or emissions limit was not adjusted. If, on the other hand, the value equal to 3*RDL was greater than the floor value or emission limit, we concluded that the calculated floor or emission limit does not account entirely for measurement uncertainty, and the value equal to 3*RDL was substituted for the adjusted floor or emissions limit (i.e., increasing the floor to be equal to 3*RDL). This adjusted value ensures measurement uncertainty is adequately addressed in the floor or the emissions limit and that the test method used to determine compliance with the emission standard will be appropriate for quantitative determination of emissions concentrations at, and above, the level of the emission standard.

Originally, the floor was calculated by multiplying individual tests by a factor of three when the result was below the RDL. This methodology has been corrected in the final rule to the standard methodology described above.

See the memo from Peter Westlin to Docket EPA-HQ-OAR-2002-0058, April 10, 2012, for further information on floor determination for instrumental test methods.

Commenter Name: Mary Sullivan Douglas

Commenter Affiliation: National Association of Clean Air Agencies (NACAA)

Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1

Comment Excerpt Number: 11

Comment: The first step in any scientifically sound measurement process is to ensure that the procedures employed are sufficiently precise to determine meaningful differences. In response to questions from industry as to whether they should extend sampling periods to ensure more precise results, EPA advised them that they did not need to and that the agency would address it the final rulemaking. EPA defines the method detection limit as, "the minimum concentration of a substance that can be measured and reported with 99% confidence that the analyte concentration is greater than zero and is determined from analysis of a sample in a given matrix containing the analyte." Where the "adjusted" average emissions of the top 12 percent is "near" the method detection level, EPA now proposes¹⁰ to increase the calculated average so that the floor is not less than 300 percent of the detection level. To justify this increase EPA observes that when measurements are near the detection level the measurement uncertainty can be as high as (+/-) 40 percent, while such uncertainty is reduced to (+/-) 15 percent if the measured value is three times (300 percent) the detection level. However, since such measurement uncertainties are necessarily part of the overall variability determined in step one of EPA's procedure, there is no need or basis to substitute this arbitrary figure for the actual emission data that the statute requires be used. Additionally, it also makes no technical sense to introduce a known error of 300 percent in the MACT floor in order to avoid a possible error of 25 percent¹¹ in any individual measurement. This step constitutes yet one more bias in favor of allowing higher levels of HAP emissions. In this rulemaking EPA proposes to compound this error by "adjusting" the detection level reported by the laboratory in accordance with established protocols, even where EPA has no information that the detection levels reported by the laboratory are incorrect.

[Footnotes]

(10) EPA employed this technique in the cement kiln New Source Performance Standard rule.

(11) This is the difference between the potential error at the detection level and that at three times the detection level.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3511-A1, excerpt 14.

We disagree with the commenter assertion that EPA, knowing many results would be at or below detection limits if it only required sample periods of one hour per run, responded to industry that the sources need not extend sample periods to ensure more precise results. In fact, enclosure 1 to the ICR letter requesting testing stated the methods and sampling times or volumes. For example, for sampling for metals, it was stated that EPA Method 29 be used and to collect a minimum volume of 4.0 cubic meters or have a minimum sample time of 4 hours per run. For dioxins/furans, enclosure 1 specified that EPA Method 23 be used and to collect a minimum volume of 2.5 cubic meters or have a minimum sample time of 4 hours per run.

Commenter Name: Vickie Woods

Commenter Affiliation: Division of Air Quality, North Carolina Department of Environment and Natural Resources (NCDENR)

Document Control Number: EPA-HQ-OAR-2002-0058-3663-A2

Comment Excerpt Number: 16

Comment: MDL. EPA has made minor adjustments to the methods used to account for measurement imprecision and presents the rationale for such improvements.

NC DAQ supports the minor adjustments EPA made to the test methods to account for measurement imprecision.

Response: The EPA thanks the commenter for their support.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 6

Comment: In the December 23, 2011 proposal EPA explained that to establish the stack test-based emission standards for different pollutants, EPA followed the following procedure:

1. EPA utilized the data obtained from two different ICRs and any additional data provided by source operators to identify the best performing sources for each source subcategory and for each pollutant.
2. Using the data for the best performers, EPA calculated the 99 percent UPL for each pollutant and source subcategory.
3. The above calculated values were compared to three times the representative detection limit (RDL) for each pollutant, and the emission standards were set at the higher of the UPL or the three times RDL value.
4. EPA calculated the RDL for each pollutant by averaging the detection limits for that pollutant as reported by the best performing sources in all subcategories.

We support EPA's decision to multiply the representative detection limit by three to determine the lowest level at which the emission standard for any pollutant could be set.

Response: The EPA thanks the commenter for their support for multiplying the representative detection limit by three.

Commenter Name: Ashok K. Jain

Commenter Affiliation: National Council for Air and Stream Improvement, Inc. (NCASI)

Document Control Number: EPA-HQ-OAR-2002-0058-3505-A1

Comment Excerpt Number: 20

Comment: Several EPA Method 10 CO concentration measurements for boilers in the Boiler MACT floors for various subcategories are at the low end of the range of the span gas concentration used to calibrate the Method 10 analyzer. In a January 20, 2011 EPA memo (EPA 2011a) Peter Westlin addressed some of the concerns with Method 10 measurement uncertainty at low concentrations. By way of an example, the memo explains how a calibration span value of 25 ppm results in an instrumental detection level of 0.9 ppm. The memo then states "Consistent with the methodology we applied for non-instrumental methods, discussed in section C of this memorandum, where we established limits no less than three times the MDL, this estimated measurement error value of about 1 ppmv would translate to a limit of 3 ppmv...One outcome of this assessment is recognition that the site-specific estimated measurement errors in some cases may be higher than some of the reported levels. Therefore, for each emission test used in the MACT floor calculations we substituted the site-specific estimated measurement error for reported values below those values in order to ensure the quality of the data used to set the floors."

In the 2009 ICR, EPA specified that all measurements below the method detection limit should be reported as being equal to the detection limit. Using such reported values, EPA identified the best performing sources in each subcategory and then calculated the UPL for each pollutant for each subcategory. The UPL estimated from these data was compared to three times the representative detection level (RDL) for each pollutant. The RDL for each pollutant was determined using the average detection limit achieved by the best performing sources which constituted the floor. The most recent procedure for calculating RDLs is detailed in a November 17, 2011 memo by Peter Westlin (EPA 2011b).

EPA then compared the UPL value to three times the RDL value for each pollutant. If $3 \times \text{RDL}$ was greater than the calculated UPL, the $3 \times \text{RDL}$ value became the emission standard in place of the UPL value.

NCASI believes the procedures followed by ERG (2011a) to determine when to replace a reported Method 10 CO concentration with the estimated measurement error (EME) prior to calculating the UPL were not consistent with the Westlin guidance. ERG replaced any concentration (at 3% O₂) less than three times the EME with three times the EME. First, it seems the actual CO concentration at stack O₂ should have been compared to the EME since the CO concentration measured by the analyzer is at stack O₂, not 3% O₂. Second, the measured CO concentration should be compared to the EME, rather than three times the EME. Only values below the EME should be set to the EME. Furthermore, a comparison of the calculated UPL with three-times the EME value, which would represent the quantitation limit (QL) of the instruments used at the sources constituting the floor, was never carried out to see if the UPL needed to be replaced by this estimate (although for CO the UPLs were invariably much higher than the QLs).

Response: We have revised the CO floor to account for several errors in the initial calculation. For those tests where oxygen concentrations in the stack were known, the comparison was revised to a stack oxygen basis instead of an oxygen corrected basis. Due to data limitations, the oxygen conditions at the stack were not known for all cases, and in these instances, the comparison was made to the oxygen adjusted values. In the revised analysis, we have corrected the error identified by NCASI by replacing any concentration less than the method detection limit (MDL) with the MDL instead of three times the MDL. Also, the revised UPL equations in the final rule were compared to the three times MDL value.

For further information on how the CO floor was set, see comment EPA-HQ-OAR-2002-0058-3511-A1, excerpt 14.

Commenter Name: Ashok K. Jain

Commenter Affiliation: National Council for Air and Stream Improvement, Inc. (NCASI)

Document Control Number: EPA-HQ-OAR-2002-0058-3505-A1

Comment Excerpt Number: 21

Comment: The following is a summary of how the 99% UPLs change when the 3 x EMEs are replaced by the respective EME values for various boiler and fuel categories. [See submittal for Table] The 99.9% UPLs are also provided since we believe the 99.9% UPL is more appropriate for determining CO limits. Note that reported concentrations were used when the value at 3% O₂ was above the EME but less than 3 times the EME. The EPA emission database does not contain the stack O₂ concentrations measured during each sampling run, so the comparison to the EME was made with CO concentrations adjusted to 3% O₂. Time did not allow for review of the original sampling reports for the best performers to obtain the CO concentrations measured in the stack to compare to the EMEs.

Response: For a response to issues with the UPL calculation and estimated CO measurement error being compared to measured emissions corrected to 3% oxygen, see comment EPA-HQ-OAR-2002-0058-3505-A1, excerpt 20. For a response to using the 99% UPL for CO instead of the 99.9% UPL, see comment EPA-HQ-OAR-2002-0058-3661-A2, excerpt 4 under the chapter for Methodology: Statistical Procedure for CO.

Commenter Name: Mary Sullivan Douglas

Commenter Affiliation: National Association of Clean Air Agencies (NACAA)

Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1

Comment Excerpt Number: 36

Comment: In the proposed calculations of MACT floors for CO for biomass sources EPA significantly alters the reported data to account for what it styles as “measurement span errors.” This appears to be double counting of variability, since any random errors in the measurement system will be reflected in the variability of the resulting data. Moreover, the method relies on the highest reported values of computed errors rather than an average of those errors.

Response: We agree that variability is accounted for in the measurement data. Data is only adjusted when the floor value falls below three times a reliable method detection limit. For a response to issues with the methodology of setting the CO floor and adjusting the database for variability, see comment EPA-HQ-OAR-2002-0058-3511-A1, excerpt 14. For a response to issues with methodology used to develop the estimated measurement error for CO, see comment EPA-HQ-OAR-2002-0058-3505-A1, excerpt 20.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 4

Comment: EPA should indicate in the final Boiler rule that when calculating TSM emissions based on Method 29 test results or fuel analysis data, if individual metals are non-detect for all 3 test runs or fuel samples, emissions of those metals should be counted as zero.

Response: We believe that when calculating total selected metals emissions based on Method 29 test results or fuel analysis data, if individual metals are below the detection limit, emissions of those metals should be counted at the detection limit. Our process for setting the floor includes consideration of these data at the detection limit and our floor limits are set to be a minimum of 3x this value. EPA method 29 provides for different detection limits for each metal analyte, and when using method 29 to quantify a single analyte, using the detection limit associated with that single analyte would be appropriate. Ergo, when evaluating the data set for TSM we recognize the overall TSM detection limit as the sum of the detection limits of the associated TSM metals. As such, we feel it is appropriate for sources to report data as emitted at the amount of the detection limit as this will not cause a noncompliance issue for the source and this provides incentive for sources to choose better performing testers and labs. We have added language to the final rule to address this issue.

Commenter Name: Dean C. DeLorey

Commenter Affiliation: The Amalgamated Sugar Company LLC (TASCO)

Document Control Number: EPA-HQ-OAR-2002-0058-3522-A1

Comment Excerpt Number: 21

Comment: Finally, the TSM rule does not address method detection limits or how to deal with laboratory results that are less than method detection limits. If a laboratory result is below the detection limit, a value of zero should be used in the TSM calculation. Please clarify.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 4.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 64

Comment: It is not appropriate to treat detection level limited data for purposes of establishing regulatory limits in the same manner as detected values because the uncertainty²² associated with measurements near or below the method detection limits is too high. In setting the standards in this rulemaking, EPA has acknowledged that the emission limit should not be set below the capability of the applicable test method. ACC supports EPA's decision to multiply the method detection limit by three to approximate the representative detection limit for each pollutant. [Footnote 22: Uncertainty here refers to the statistical expression of measurement error, such as defined in ASME Performance Test Code 19.1, rather than an inference of something which is unknown.]

Response: The EPA thanks the commenter for their support of multiplying the method detection limit by three.

For a response on how detection level limited data is handled in establishing floor values, see comment EPA-HQ-OAR-2002-0058-3511-A1, excerpt 14.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 52

Comment: In response to EPA's reconsideration of the Boiler MACT and CISWI standards, NCASI submitted extensive comments to EPA which noted that (1) source emission testing has three components, namely source sampling, sample recovery, and sample analysis, (2) the errors associated with sample collection and recovery are much greater than those associated with sample analysis, and (3) to determine the source test method detection and quantitation limit, EPA procedures must account for the variability associated with source sampling and sample recovery.

These issues were also identified in an ASME report entitled "Reference Method Accuracy and Precision (ReMAP), Phase 1," which examined the precision of selected EPA source emission test methods. The report, which is referenced in the December 23, 2011 EPA proposal, makes several important points: (1) there are both random errors and systematic errors (bias in the measurement process), (2) "the magnitude of random errors associated with extraction and recovery of the sample from the stack might be expected to vary in proportion to stack concentrations," and (3) "estimation of method precision must be based on data from special tests where multiple sampling trains are used simultaneously to determine the stack pollutant concentration." In its proposal, EPA has ignored these issues and considered only the precision of laboratory analytical measurements in establishing method RDLs. We urge EPA to carefully evaluate the method quantitation limited-related issues raised by NCASI in its July 15, 2011 comments and the comments submitted in response to the December 23, 2011 proposal.

We believe that consideration of these issues will result in higher RDL values for several of EPA's reference test methods and will raise the emission standards for many source categories.

We are, however, concerned that EPA's approach in calculating the representative detection limits for various pollutants by averaging the detection limits achieved by the best performers is based only on partial information on method detection limits and is, consequently, incorrect and needs to be modified.

Response: We agree with the commenter that there are errors associated with the extraction and recovery of the samples from the stack. We believe that the calculation of the floor by the upper predictive limit takes into account variability in the operation and emissions of the source. To ensure measurement variability is adequately addressed, when there are undetectable measurements, we compare the calculated floor against three times the representative method detection limit (RDL), or the associated level of quantitation of the test method. If the floor is less than three times the RDL, we adjust the floor level to three times the RDL so that measurement variability is sufficiently addressed.

We disagree with the commenter that this adjustment of three times the RDL does not properly account for the random measurement errors addressed in the ASME study, which also includes errors associated with laboratory analysis.

Commenter Name: Derek Stephens

Commenter Affiliation: Advanced Industrial Resources, Inc. (AIR)

Document Control Number: EPA-HQ-OAR-2002-0058-3456-A2

Comment Excerpt Number: 1

Comment: The following provides clarification that the detection limits on dioxin/furan testing commonly reporting with stack test results reported by Advanced Industrial Resources (AIR) reflect the analytical detection limits as opposed to the overall detection limits of the stack test methods themselves. AIR always attempts to minimize variability on the emissions results associated with actual sampling events but it should be understood that there is not attempt to quantify those factors in reporting of detection limits.

Prior to conducting a sampling event, AIR attempts to estimate a source's expected pollutant emission concentration and exhaust gas stream volume (dry, standardized) in order to determine the sample volume and duration necessary to obtain a detectable quantity of pollutant in the collected samples. However, ultimately, the detectable limit reported is defined within the analysis process. Therefore, when reporting emission results, the final quantity reported by the analysis process, whether it is an actual measured quantity or the analytical detection limit, establishes whether or not the value reported (i.e., emission ate) is above or below a detectable level.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 52.

Commenter Name: Ashok K. Jain

Commenter Affiliation: National Council for Air and Stream Improvement, Inc. (NCASI)

Document Control Number: EPA-HQ-OAR-2002-0058-3505-A1

Comment Excerpt Number: 13

Comment: EPA should change the 3 x RDL values used in the proposed regulation to the values shown in Table 3 above, if method RDL values are not found in the test method reports. [See submittal for Table 3]

Response: We do not expect to find RDL values in the test reports, but we do expect method detection limit (MDL) results to be included in the ICR emission testing reports, and have used those data to develop RDL values from the pool of emission test data, as suggested by comment.

Commenter Name: Ashok K. Jain

Commenter Affiliation: National Council for Air and Stream Improvement, Inc. (NCASI)

Document Control Number: EPA-HQ-OAR-2002-0058-3505-A1

Comment Excerpt Number: 14

Comment: EPA should re-examine the data in the ReMAP study to develop new reference method detection

limit values for the remaining pollutants.

Response: EPA evaluated data returned from this ICR testing to develop representative method detection limits used for emissions floor setting decisions in this rule. Data from the ReMAP study is not as informative as using the data collected from the source category specific ICR for setting RDL values.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 65

Comment: ACC is concerned that EPA's approach in calculating the method detection limit by averaging the detection limits achieved by the best performers is based only on partial information on method detection limits and is, consequently, incomplete and needs to be modified to accommodate the following issues: (1) source emission testing has three components, namely source sampling, sample recovery, and sample analysis, (2) the errors associated with sample collection and recovery are much greater than those associated with sample analysis, and (3) to determine the source test method detection and quantitation limit, EPA procedures must account for the variability associated with source sampling and sample recovery.

These issues were also identified in an ASME report entitled "Reference Method Accuracy and Precision (ReMAP), Phase 1," which examined the precision of selected EPA source emission test methods. The report, which is referenced in the Reconsideration Proposal, makes several important points: (1) there are both random errors and systematic errors (bias in the measurement process), (2) "the magnitude of random errors associated with extraction and recovery of the sample from the stack might be expected to vary in proportion to stack concentrations," and (3) "estimation of method precision must be based on data from special tests where multiple sampling trains are used simultaneously to determine the stack pollutant concentration." In its proposal, EPA has ignored these issues and considered only the precision of laboratory analytical measurements in establishing method representative detection limits (RDLs). ACC believes that consideration of these issues will result in higher RDL values for several of EPA's reference test methods and will raise the emission standards for many source categories.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 52.

Commenter Name: Ashok K. Jain

Commenter Affiliation: National Council for Air and Stream Improvement, Inc. (NCASI)

Document Control Number: EPA-HQ-OAR-2002-0058-3505-A1

Comment Excerpt Number: 9

Comment: The issues related to test method detection limits were identified in an ASME report (Lanier and Hendrix 2001) entitled "Reference Method Accuracy and Precision (ReMAP), Phase 1," which examined the precision of selected EPA source emission test methods. The report, which is referenced in the December 23, 2011 EPA proposal, makes several important points: (1) there are both random errors and systematic errors (bias in the measurement process), (2) "the

magnitude of random errors associated with extraction and recovery of the sample from the stack might be expected to vary in proportion to stack concentrations,” and (3) “estimation of method precision must be based on data from special tests where multiple sampling trains are used simultaneously to determine the stack pollutant concentration.” Using the data presented in the ReMAP study, NCASI determined the quantitation limits, which are essentially the same as 3 x RDLs, for various EPA source test methods. The results of this analysis were described in detail in the July 15, 2011 letter to Brian Shrager (Attachment 4) and are summarized in Table 3. [See submittal for Table 3 and Attachment 4] The ReMAP study also provides data on the detection limits for select metals when using EPA Method 29. All these data may be useful to EPA in establishing the RDL values for the entire method as opposed to the analytical component of the test method.

Response: In developing RDL values for these data the EPA used MDL values from the ICR test reports themselves. ReMAP data was not included in that evaluation. The EPA feels the ICR specific data set better addresses matrix interferences and the specific compliance determination method affecting this source category.

Commenter Name: Ashok K. Jain

Commenter Affiliation: National Council for Air and Stream Improvement, Inc. (NCASI)

Document Control Number: EPA-HQ-OAR-2002-0058-3505-A1

Comment Excerpt Number: 8

Comment: We are concerned that EPA has misinterpreted the method detection limit data submitted with emission test results and thus has reached incorrect conclusions regarding test method RDL values. As NCASI explained in its letter to Brian Shrager of EPA [See submittal for Attachment 4], source emission testing has three components, viz., source sampling, sample recovery, and sample analysis; the errors associated with sample collection and recovery are much greater than those associated with sample analysis; and to determine the source test method detection and quantitation limit, EPA procedures must account for the variability associated with source sampling and sample recovery in addition to the variability associated with sample analysis. However, as shown in Attachment 3, testing companies do consider errors associated with sample collection and recovery in determining method detection limits. [See submittal for Attachment 3]

Response: See the response to comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 52.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 138

Comment: NON-DETECT DATA

In setting limits under this rule, EPA has attempted to ensure that they are not set at less than 3 times a "representative detection limit" or RDL.³⁹ Therefore, EPA has not set out procedures for handling non-detect data obtained from fuel analyses or stack testing. The RDL was determined based on only the laboratory analysis data from the top performing units, and does not take into

account the error associated with sampling procedures. ACC has not had adequate time to evaluate all of the limits against what our members typically experience as non-detect levels from the companies used by our members. However, ACC requests that EPA include a provision in the rule that states if a facility does a stack test or fuel analysis using the appropriate methods and procedures set out in the rule and obtains a result that is labeled as non-detect but is above the emission limit, the source has 60 days to retest and demonstrate that emissions or fuel constituents are below the standard.

[Footnote 39: 76 Fed. Reg. 80611.]

Response: We believe that it is appropriate to use the detection limit value for determining compliance when data is analyzed below the detection limit. The detection limit provides reasonable assurance of compliance because we have set the emission floor no lower than 3x the RDL for the compliance test method. This means that reporting at the method detection level will not create a compliance issue for the source and it provides incentive to the source to select a tester and laboratory who will conscientiously evaluate their detection level prior to conducting the source test and determine appropriate pre-test goals for a target detection level. We have added language to the final rule to address this issue.

While we understand ACC's concerns, we do not feel that it is appropriate to include a provision for allowing retesting when the detection limit causes an exceedance of the standard. While the facility may certainly choose to retest or may be required to do so by the regulating authority, we do not feel that this provision is appropriate for the rule. We expect facilities, testers, and laboratories to use best practices to obtain detection levels that are reasonably low enough to show compliance with the emission standard.

For a response to error associated with sampling procedures, see comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 52.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 113

Comment: In setting limits under this rule, EPA has attempted to ensure that they are not set at less than 3 times a "representative detection limit" or RDL. Therefore, EPA has not set out procedures for handling non-detect data obtained from fuel analyses or stack testing. The RDL was determined based on only the laboratory analysis data from the top performing units, and does not take into account the error associated with sampling procedures. We have not had adequate time to evaluate all of the limits against the non-detect levels our members typically experience from the source testing and laboratory companies they use. However, we request that EPA include a provision in the rule that states if a facility does a stack test or fuel analysis using the appropriate methods and procedures set out in the rule and obtains a result that is labeled as non-detect but is above the emission limit, the source has 60 days to retest and demonstrate that emissions or fuel constituents are below the standard.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 138.

Commenter Name: Ashok K. Jain

Commenter Affiliation: National Council for Air and Stream Improvement, Inc. (NCASI)

Document Control Number: EPA-HQ-OAR-2002-0058-3505-A1

Comment Excerpt Number: 6

Comment: EPA has assumed that the procedure used by different testing companies to establish the analytical method detection limit is correct and follows a methodology established by EPA. This issue is significant because, in its air emission testing methods, EPA has not defined a methodology for determining the air emission test method detection limits. Consequently, many testing companies rely upon water methods for determining their analytical method detection limits. However, this is not the case for all testing companies. For example, in its Revised Assessment of Detection and Quantitation Approaches (EPA 2004) applicable to test methods used for water analysis, method detection limit is defined as 3.14 times the standard deviation of seven replicate analyses of very low level samples. While some laboratories used this practice, as shown in Table 2, one testing company reported its replicate analysis standard deviation as the detection limit instead of multiplying it by 3.14 [See submittal for Table 2 and Attachment 3].

Response: While we do not require sources to follow a specific methodology for determining method detection limits, we have provided instruction for, and advise sources to use EPA Method 301, section 15 as the standard methodology for determining method detection limits. Where sources have not used Method 301 procedures, we have asked that they provide the scientific basis for their technique. Many of the data used to develop the RDL values were from labs who used this methodology for determination of their detection limit.

Commenter Name: Ashok K. Jain

Commenter Affiliation: National Council for Air and Stream Improvement, Inc. (NCASI)

Document Control Number: EPA-HQ-OAR-2002-0058-3505-A1

Comment Excerpt Number: 10

Comment: Further support for the need to utilize the detection limit for the entire test method is found in the results of a recent study aimed at examining the performance of PM CEM on a multi-fuel boiler. During this study simultaneous PM tests on the stack were carried out with two separate EPA Method 5 sampling trains. The results of these simultaneous tests, which are summarized in Table 4 and are described in detail in Attachment 1, show that when simultaneous Method 5 tests were carried out at a multi-fuel boiler, the unbiased standard deviation of the duplicate measurements calculated according to the protocol used in the ReMAP study was estimated to average 1.5 mg/dscm. [See submittal for Attachment 1] As compared to the 1.5 mg/dscm standard deviation in the above study, the standard deviation of quarterly replicate weighings of beakers, summarized in Table 1, shows a standard deviation of 0.6 mg at a tare weight of 103 gm. [See submittal for Table 1] When multiplied by 3.14 as per EPA methodology (EPA 2004), this would give an RDL of 5 mg for Method 5 whereas the laboratory test-based method would give an RDL of 2 mg for Method 5.

Response: We have used our published level of quantitation for particulate matter data of 1.0 mg. This detection limit accounts for the systematic error from the inherent blank in Method 5. See EPA Method 5I for a discussion on PM detection limits and level of quantitation. For a

response to the validity of the 2004 EPA guidance for determining method detection limits and how it pertains to this rulemaking, see comment EPA-HQ-OAR-2002-0058-3505-A1, excerpt 6. For discussion on the ReMAP study, see comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 52.

Commenter Name: Ashok K. Jain

Commenter Affiliation: National Council for Air and Stream Improvement, Inc. (NCASI)

Document Control Number: EPA-HQ-OAR-2002-0058-3505-A1

Comment Excerpt Number: 11

Comment: EPA should audit the procedure used by laboratories/testing companies to ensure that a consistent method is used to determine the method detection limit.

Response: While we do not require sources to follow a specific methodology for determining method detection limits, we have provided and advised sources to use EPA Method 301, section 15, as the standard methodology for determining method detection limits. The National Environmental Laboratory Accreditation Conference (NELAC) Institute (TNI) works to foster generation of environmental data of known and documented quality. Laboratories may apply to TNI for accreditation, and some state agencies require laboratories generating data to be accredited in order to for the data to be acceptable. Even if a state does not require laboratories to be accredited, as the delegated authority for enforcing the rule, the state agency or regional office has the right to audit testers and laboratories and all of the procedures used, including the development of method detection limits.

Commenter Name: Ashok K. Jain

Commenter Affiliation: National Council for Air and Stream Improvement, Inc. (NCASI)

Document Control Number: EPA-HQ-OAR-2002-0058-3505-A1

Comment Excerpt Number: 7

Comment: In describing the procedure for calculating the RDL, in the November 17, 2011 memo EPA has stated that “By limiting the data set to those tests used to establish the floor or emissions limit (i.e., best performers), we believe that the result is representative of the best performing testing companies and laboratories using the most sensitive analytical procedures.” If EPA believes this to be true, what is EPA’s rationale for further adjusting these values downward by taking an average of the detection limits reported by the nation’s “best performing testing companies and laboratories using the most sensitive analytical procedures”? We believe that EPA’s own conclusion would lead to using the highest detection limit achieved by the best performing testing companies as the method RDL. We also note that such an interpretation is too restrictive and EPA should use 90 or 95th percentile of the method detection limit data to set method RDL values as described in NCASI’s July 15, 2011 letter [See submittal for Attachment 4].

Response: In determining the representative method detection limit (RDL), we averaged the detection limits achievable in the data set used to set the floor. In doing this we are basing the detection limit of the test method on data representative of a pool of labs available to sources and testers who conscientiously target low detection levels from this source category. Selecting the highest detection limit merely makes allowances for the poorest lab results, a factor we wish to

avoid when setting emission floors. Moving forward to future testing efforts we want sources and their testers to make informed assessments of detection limit needs when conducting performance tests. By basing the RDL on a pool of lab data we provide a reasonable assessment of what can be detected by a cross section of testers and labs. We have accounted for measurement variability by multiplying the RDL by three when comparing it the floor's upper predictive limit and we compare this 3xRDL value with our 99% UPL value that accounts for source operational variability. When we base the floor data on the higher of these two numbers we feel that we have adequately addressed variability in the floor data set.

Commenter Name: Ashok K. Jain

Commenter Affiliation: National Council for Air and Stream Improvement, Inc. (NCASI)

Document Control Number: EPA-HQ-OAR-2002-0058-3505-A1

Comment Excerpt Number: 12

Comment: EPA should preferably use 90 or 95th percentile of the audited detection limits to set method RDLs as outlined in the recommendation of the Federal Advisory Committee on detection and quantitation approach and detailed in the NCASI letter to Brian Shrager [See submittal for Attachment 4], or as a minimum, use the maximum RDL from the boiler MACT data set corrected to reflect method detection limit.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3505-A1, excerpt 7.

Commenter Name: Lee Zeugin and Lauren Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1

Comment Excerpt Number: 4

Comment: Even if the Agency is reluctant to develop a work practice standard for organic HAP emissions from all IB subcategories, it should, at the very least, examine the available organic test data for each subcategory to determine the percentage of measurements below the method detection limit as well as a level three times the method detection limit - the point at which EPA has stated that emissions can be accurately measured. Extensive testing during the EGU MACT rulemaking of organic emissions from coal fluidized bed units, pulverized coal units and oil-fired units showed the vast majority of these organic measurements were below the method detection limit and/or three times that level. Coal- and oil-fired IBs of similar designs should have similar emission profiles because the equipment is designed based on the same scientific principles.

Response: We did not compute a 3*RDL limit for organic HAP in the proposed rule. Setting a standard for organic HAP is outside the scope of this reconsideration action.

Commenter Name: Douglas Emerson et al.

Commenter Affiliation: American Crystal Sugar Company et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3675-A2

Comment Excerpt Number: 6

Comment: It does appear that the particulate matter emission limits in the rule were set considering the likely detection limit of the stack testing procedure; however, it does not appear that the precision of the test method was considered. Precision is a function of the repeatability of a procedure and is the determining factor of the detection limit. As referenced in 40 CFR 136, Appendix B, Definition and Procedure for the Determination of the Method Detection Limit, the proper procedure to determine the MDL would involve seven simultaneous stack tests with statistical analysis for the seven results. While focused primarily on water analysis, the methods presented in Part 136, Appendix B, were designed for applicability to a broad variety of physical and chemical methods. Following this methodology would be very expensive and likely possible for only large rectangular stacks where seven simultaneous samples could be taken without undue interference from adjacent test probes.

Presumably, because of the difficulty and expense in performing such an analysis for numerous source types, the EPA published a discussion of error sources for particulate matter stack tests in 1974 that could be relied upon in lieu of inadequate MDL data. The EPA document is "Administrative and Technical Aspects of Source Sampling for Particulates" (EPA 450/3-74-047, August 1974, Office of Air and Waste Management, Office of Air Quality Planning and Standards, Research Triangle Park, NC 27711), Chapter 8. The discussion provides a summation of the possible errors of measurement of each portion of the testing protocol and concludes that the maximum error of a given particulate test is 15% with a probable error range of 10%. The conclusions were based on the assumption that 200 mg of residue would be collected, which was the norm for the time. However, changing the weight of the residue to a smaller amount (10 mg) more reflective of modern test levels is not anticipated to impact the percent error significantly.

A discussion of error is not the same nor should it be substituted for a properly determined MDL. However, the error analysis does point out an issue with the proposed MACT emission limits for particulate matter. A 10% error range means that the result of the analysis has only one significant figure. Therefore, a result of 0.028 lb/MMBtu should only be reported as 0.03 lb/MMBtu. Failure to round the result properly could result in the appearance of a violation where one may not have occurred and take away necessary flexibility to address potential test errors.

Response: The Laxton 1990 Memo (Emissions Measurement Center Technical Information Document 024) provides the guidance related to the handling of significant figures throughout the calculation of emissions floors and the use of two significant figures for emission limits. As such the emission limit of 0.028 lb/MMbtu may be expressed and appropriately reported as 2.8E-02 lb/MMbtu.

For a response to treatment of measurement error, see comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 52.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 143

Comment: In setting the Boiler MACT standards, EPA has acknowledged that the emission limit should not be set below the capability of the applicable test method. However, EPA did not use the widely accepted definition of method detection limit, which is based on the capabilities of multiple commercial laboratories to analyze a sample and identify the presence of a chemical above the “noise” level. In its place, EPA coined a new term, “representative method detection limit” (RDL) to define a measurement method detection limit which is based on the laboratory detection limits reported for the tests with the lowest emissions. This erroneous methodology resulted in estimating D/F detection limits that are over 100 times lower than those regularly achieved by commercial laboratories, based on an analysis documented in previous comments by AF&PA and the National Council for Air and Stream Improvement (NCASI).²⁰

The detection limit of an analytical method is commonly defined as the lowest concentration that can be distinguished from replicate blanks. The quantitation limit of a method is defined as the smallest concentration of the substance which can be measured with an acceptable level of uncertainty. Detection limits and quantitation limits are defined in a scientific, non-arbitrary manner in various widely-published peer-reviewed consensus guidelines²¹ and EPA documents. Quantitation limits of test methods have great significance when measuring very low concentrations of pollutants. In practice, reported values below the method’s quantitation limit should not be treated as real values.

The majority of a federal advisory committee on method detection and quantitation limits recommended that the quantitation limit of a test method should be based on the 95th percentile of what is being achieved by the commercial laboratories.²² Using this approach and rounding up the quantitation limit to a single digit, as EPA has done for floor setting, would result in a D/F TEQ quantitation limit of 0.2 ng/dscm based on analytical procedures alone. However, using the results of the ASME ReMAP study,²³ which evaluated the precision of Method 23D/F stack testing measurements, a D/F TEQ quantitation limit of 0.27 ng/dscm is derived, which addresses the uncertainty of all of the test method components.

[Footnote 20: The National Council for Air and Stream Improvement is an independent, non-profit research institute that focuses on environmental topics of interest to the forest products industry. Established in 1943, NCASI is recognized as the leading source of reliable data on environmental issues affecting this industry.]

[Footnote 21: For example, Keith, L.H. et al., Principles of Environmental Analysis, *Anal. Chem.* 1983, 55, 2210-2218.]

[Footnote 22: Report of the federal advisory committee on detection and quantitation approaches and uses in Clean Water Act Programs submitted to the Environmental Protection Agency (EPA). December 2007.]

[Footnote 23: Lanier, W.S. and Hendrix, C.D. Final Report--Reference Method Accuracy and Precision (ReMAP): Phase 1 Precision of Manual Stack Emission Measurements, ASME International, Washington, D.C. (2001).]

Response: We did not propose numerical emission limits for dioxins/furans in this rule. The final rule will not be changed to add numerical emission limits. Dioxins/furans standards are based on a work practice to conduct a boiler or process heater tune-up.

3D. MACT Floor Methodology: Output based standard (Alternative) - Boiler Efficiency Analysis

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 48

Comment: Although EPA did not collect out-put emissions data or set output-based floors, the agency proposes to offer sources the option of complying with output-based emission standards. Specifically, EPA proposes to allow sources to meet standards that are converted from the floors it did set with a pre-determined conversion factor. Facilities that currently have relatively low efficiency would be unlikely to choose to meet the output-based standards because they would likely be more stringent than the standards EPA actually sets. Facilities with relatively high efficiencies, however, would likely choose to use the output-based standards because they would be less stringent.

EPA's output based standards do not reflect either the maximum degree of reduction that is achievable or the actual performance of the relevant best units. Had EPA calculated output based floors (properly), such floors would reflect the superior performance of the more efficient boilers. Moreover, EPA would have been forced to recognize that superior design and efficiency are themselves means by which cleaner sources achieve better emission levels. Because EPA did not set output based floors, however, the optional-output based standards do not purport to meet the Clean Air Act's floor requirements. Indeed, converting from EPA's standards to output-based standards could not possibly work without information highly specific to each individual source that chose to use it. But EPA does not require such information – choosing instead to offer a pre-determined conversion factor– and if the agency did require it, the option of using output-based standards would hold no allure for industry because it would not provide a compliance option less stringent than the floors EPA set.

Response: We disagree with the commenter that alternative output based standards do not reflect the actual performance of the relevant best performing units. Contrary to the commenter's assertion, EPA did in fact require output information specific to the best performing units and did not use a pre-determined conversion factor. The output-based limits are in fact based on data collected from the best performing units, as explained in the memorandum "Development of Alternate Equivalent Output-Based Emission Limits for Boilers and Process Heaters located at Major Source Facilities" (Docket ID No. EPA-HQ-OAR-2002-0058-3275). In the memo, we describe the process in the development of the alternate output-based emission limits that are equivalent to the MACT floor determinations for boilers and process heaters. First, we conducted an effort, under authority of section 114 of the Clean Air Act, to obtain steam/output data (flow, temperature, and pressure) for the test period corresponding to the reported emission data from

the best performing units comprising the proposed MACT floor pool. In determining alternate equivalent output-based emission limits, we determined for each of the best performing units the boiler efficiency for each of the boilers having available steam/output data. We determined the average boiler efficiency factor for each subcategory from the individual best performing units in that subcategory by calculating the average efficiency of this group. We applied the average boiler efficiency factor for each particular subcategory to the MACT floor (lb/million Btu heat input) emission limits for that particular subcategory to develop the alternate output-based emission limits. (The average subcategory specific boiler efficiency was revised based on a more appropriate approach for calculating boiler efficiency - See Docket ID No. EPA-HQ-OAR-2002-0058-3376)

The alternate output-based emission limits were proposed to encourage energy efficiency. The output-based limits are equivalent in stringency to the MACT floor because a unit operating at the average boiler efficiency of the best performing units will emit the identical mass (pound/hour) of HAP emissions complying with either the input-based limits or the output-based limits. Further, a unit operating at a boiler efficiency greater than the average boiler efficiency of the best performing units would emit less HAP on a mass-basis if complying with the input-based limits because the unit is combusting less fuel to generate the same output.

Commenter Name: Michael L. Krancer

Commenter Affiliation: Pennsylvania Department of Environmental Protection (DEP)

Document Control Number: EPA-HQ-OAR-2002-0058-3507-A1

Comment Excerpt Number: 4

Comment: The EPA has proposed several changes to the output-based provisions in the reconsidered rule to address issues raised regarding boiler efficiency for this compliance option. The boiler efficiency calculation has been revised to include the heat (energy) associated with the feedwater. The DEP supports the revised output-based standards compliance option opportunity provided for existing boilers. The DEP agrees with the revision to the efficiency calculation and believes that the revised equation will result in more realistic boiler efficiencies or output-based standards.

Response: The EPA thanks the commenter for their support.

Commenter Name: Michael Bradley

Commenter Affiliation: The Clean Energy Group

Document Control Number: EPA-HQ-OAR-2002-0058-3495-A1

Comment Excerpt Number: 5

Comment: For this proposal, EPA has reassessed the Agency's calculations of boiler efficiencies upon which the output-based limits are calculated. The calculations in the final rule neglected to account for feedwater temperature, resulting in assumed efficiencies of or over 100 percent. Thus, EPA proposes a corrected methodology and standards. The Clean Energy Group supports this correction that will allow for output-based standards as an equivalent alternative.

Response: The EPA thanks the commenter for their support.

Commenter Name: Holly R. Hart
Commenter Affiliation: United Steel Workers (USW)
Document Control Number: EPA-HQ-OAR-2002-0058-3498-A1
Comment Excerpt Number: 7

Comment: USW notes EPA's needed modifications to the steam efficiency calculations at pages 80606-7 and believes that the modifications are a much-needed improvement to the major source rule.

Response: The EPA thanks the commenter for their support.

Commenter Name: Jessica Bridges
Commenter Affiliation: United States Clean Heat & Power Association (USCHPA)
Document Control Number: EPA-HQ-OAR-2002-0058-3501-A1
Comment Excerpt Number: 1

Comment: Changes to the Boiler Efficiency calculation to facilitate output-based standards are appropriate. EPA should also consider the authoritative data contained in the Energy and Environmental Analysis report from 2005 that is a boiler industry survey putting efficiency rates at approximately 78% (averaging black liquor fired, coal, and natural gas-fired systems.) It is available on the American Boiler Manufacturers Association website.⁶

[Footnote]

(6) http://www.abma.com/ICI_Boiler_Population_Characterization.pdf

Response: The EPA thanks the commenter for their support of the revisions to the output-based standards.

The 2005 Energy and Environmental Analysis report data is not appropriate for converting the MACT floor limits from an input basis to an output basis because it does not present the boiler efficiency of the best performing units that represent the MACT floor. However, the report does support the revised approach for calculating the actual boiler efficiency of the best performing units. That is, the recalculated boiler efficiencies included the heat (energy) associated with the feedwater which was initially disregarded resulting in efficiencies that were unrealistically high.

Commenter Name: Mary Sullivan Douglas
Commenter Affiliation: National Association of Clean Air Agencies (NACAA)
Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1
Comment Excerpt Number: 39

Comment: NACAA has long supported the general notion of output-based standards as a way to encourage energy efficiency and mitigate emissions of air pollutants. However, unlike the EGU sector, determining energy efficiency improvements from a variety of industrial processes is a complex task that EPA has not yet addressed. Moreover, EPA has not developed the MACT floors using net output-based data and is not proposing to promulgate mandatory output-based MACT limits. Rather, it has converted the results of MACT data for sources selected as best

performing units on an input-basis and proposes to offer sources the option of complying with either the input-based limits or the converted limits. In addition, the uncertainties associated with past and future determinations of the unit's net heat rate are larger than potential efficiency gains that may result from adoption of output-based standards for existing units using common factors. NACAA believes that the most significant effect of offering existing sources the option of output-based standards based on a pre-determined conversion factor will be a reduction in the effectiveness of the rule, rather than any measureable improvement in efficiency of existing or new sources.

Response: For a response to issues with the conversion factor approach used to develop output-based standards, please see comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 48.

EPA disagrees that output based standards are inappropriate for the boilers and process heaters source category. In particular, we disagree that that the option of complying with output-based standards will be a reduction in the effectiveness of the rule, which the commenter claims will occur because the standards are based on a pre-determined conversion factors. The conversion factors are based on actual output data from the same units that EPA determined were the best performers and therefore used to calculate the input based MACT floor limits. Compliance with the alternate output-based emission limits are based on actual output data from the affected unit, not on determination of the unit's heat rate. The alternate output-based emission limits are considered equivalent to the input-based emission limits because the mass emissions (pounds per hour) will be equivalent from a unit complying with either limit.

Commenter Name: Mary Sullivan Douglas

Commenter Affiliation: National Association of Clean Air Agencies (NACAA)

Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1

Comment Excerpt Number: 40

Comment: For existing units, the principal effect of an "optional" output-based standard would be to establish a class of "winners" that qualify for lower emission rates based on their currently existing condition, rather than providing an incentive to reduce emissions. Since facilities with low efficiencies (high heat rates) may elect to comply with the input-based limit, the only "losers" in this process are the members of the public who are subjected to higher emissions of HAPs than would otherwise be the case. For this reason EPA should not allow an output-based standard as an option for existing sources to employ, but should set standards based on net output emissions data. This could be accomplished at the next review of the standard, as required by the CAA every eight years and discussed below.

Response: We disagree that the alternate output-based standards will subject the public to higher emissions of HAP, see the response to comment EPA-HQ-OAR-2002-0058-3525-A1, excerpt 39. The purpose of the alternate output-based standards is to encourage energy efficiency. A source may determine that improving its boiler efficiency may be more cost effective in complying with the Boiler MACT than installing or upgrading its control equipment. Operating at improved efficiency will better the public even more since increase efficiency results in lower fuel consumption and reduction of all emissions, not just HAP emissions.

Commenter Name: Mary Sullivan Douglas
Commenter Affiliation: National Association of Clean Air Agencies (NACAA)
Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1
Comment Excerpt Number: 41

Comment: Opportunities for improvement in the heat rate of existing sources are relatively small. In addition, many efficiency improvement options, such as soot removal, are not permanent and require ongoing maintenance to sustain improved performance. Before proceeding in this area EPA should develop a record that would enable accurate measurement and determination of sustainable efficiency improvements. The record in this rulemaking is not sufficient to establish such procedures.

Response: Compliance with the alternate output-based standards are no less stringent than with the heat input emission limits, see the response to comment EPA-HQ-OAR-2002-0058-3525-A1, excerpt 39. Whatever improvements are made in boiler efficiency they will need to be maintained for the source to comply on a continuous basis.

Commenter Name: David Gardiner
Commenter Affiliation: The Alliance for Industrial Efficiency
Document Control Number: EPA-HQ-OAR-2002-0058-3683-A2
Comment Excerpt Number: 3

Comment: We Commend EPA for Modifying the Output-Based Compliance Option So that More Facilities Can Benefit.

While the original Proposed Rule included numerous provisions to encourage greater efficiency of regulated boilers, it failed to provide for an output-based emission standard. As EPA has recognized in other contexts, output-based regulations “encourage[] energy efficiency and clean energy supply, such as combined heat and power (CHP), by relating emissions to the productive output of the process rather than the amount of fuel burned.”⁶ EPA largely corrected this oversight in the March 2011 Rule by providing an output-based standard as an alternative compliance mechanism. Therein, EPA recognized that this alternative standard “provide[s] a regulatory incentive to enhance unit operating efficiency and reduce emissions.” Unfortunately, the February Rule included some minor errors, which limited the efficacy of the output-based standard. These errors are corrected in the December Rule.

We commend EPA for making modest improvements to the output-based standard to make this provision more effective.

[Footnote 6: U.S. EPA, “Output Based Environmental Regulations Fact Sheet” (http://www.epa.gov/chp/state-policy/obr_factsheet.html)]

Response: The EPA thanks the commenter for their support.

Commenter Name: Timothy Serie
Commenter Affiliation: American Coatings Association (ACA)

Document Control Number: EPA-HQ-OAR-2002-0058-3502-A1

Comment Excerpt Number: 3

Comment: ACA generally supports the following proposed changes in the Boiler MACT rule:

Change to the boiler efficiency analysis allowing for the use of output-based limits as a compliance option to achieve emissions reductions in addition to the input-based limits

Response: The EPA thanks the commenter for their support.

Commenter Name: David A. Buff, Golder Associates Inc.

Commenter Affiliation: Florida Sugar Industry (FSI)

Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1

Comment Excerpt Number: 5

Comment: FSI supports EPA's decision to promulgate output-based limits because, among other things, they provide the FSI and other members of the regulated community with greater flexibility for demonstrating compliance with the MACT standards.

Response: The EPA thanks the commenter for their support.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 11

Comment: OUTPUT BASED EMISSION LIMITS

ACC supports the flexibility provided by the output based emission limits and EPA's acknowledgement of credit that should be provided to sources that improve their energy efficiency and reduce emissions using a pollution prevention-type approach.

Response: The EPA thanks the commenter for their support.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 122

Comment: We support the flexibility provided by the output based emission limits and EPA's acknowledgement of credit that should be provided to sources that improve their energy efficiency and reduce emissions using a pollution prevention-type approach.

Response: The EPA thanks the commenter for their support.

3E. MACT Floor Methodology: Output based Standard (Alternative) - Electric generation units

Commenter Name: Jessica Bridges

Commenter Affiliation: United States Clean Heat & Power Association (USCHPA)

Document Control Number: EPA-HQ-OAR-2002-0058-3501-A1

Comment Excerpt Number: 28

Comment: 40 CFR 63.7575, Revise the definition of “steam output” to include a description of the total energy output for a boiler that generates only electricity. This is appropriate.

Response: The reconsideration proposed definition of "Steam output" was revised from the definition in the March 2011 final rule to include the situation when a boiler generates only electricity, see item (3) of the definition.

Commenter Name: Jessica Bridges

Commenter Affiliation: United States Clean Heat & Power Association (USCHPA)

Document Control Number: EPA-HQ-OAR-2002-0058-3501-A1

Comment Excerpt Number: 2

Comment: The revision to the definition of “steam output” to provide fuel-specific conversion factors in units of pounds per megawatt-hour is appropriate.

Response: The EPA thanks the commenter for their support.

Commenter Name: Jessica Bridges

Commenter Affiliation: United States Clean Heat & Power Association (USCHPA)

Document Control Number: EPA-HQ-OAR-2002-0058-3501-A1

Comment Excerpt Number: 3

Comment: The clarification that output-based standards are alternative standards to the input-based standards is appropriate.

Response: The EPA thanks the commenter for their support.

103G. MACT Floor Methodology: HCl - Fuel Variability

Commenter Name: James Johnson

Commenter Affiliation: United States Beet Sugar Association (USBSA)

Document Control Number: EPA-HQ-OAR-2002-0058-3508-A1

Comment Excerpt Number: 5

Comment: In the reconsideration of the Boiler Rules, EPA has failed to introduce standards that sufficiently take into account the inherent variability in operations. Variability is a known part of operations at facilities with industrial boilers. While the utilization of the upper prediction limit (UPL) does allow for some variability based on stack tests, there are meaningful differences between the results of stack tests, which are conducted at full-load, steady-state operations and

real-world operations where fluctuations in operational conditions are the norm. The emission limits in the Boiler Rules consider testing variability but do not reflect operational variability. The D.C. Circuit has held that variability, particularly in emission controls, must be accounted for when setting MACT standards.¹¹ According to the D.C. Circuit, the CAA's statutory requirements for setting the MACT floor authorize EPA to set a standard which reflects what the best performing units can achieve under "the worst reasonably foreseeable circumstances."¹² To account for the worst reasonably foreseeable circumstances, EPA is required to estimate the variability associated with all factors that impact a source's emissions, including operational and fuel factors.¹³

USBSA supports EPA's exercise of discretion to account for variability in the standard but recommends that the emission limits also reflect operational and fuel variability in addition to the UPL. EPA properly chose to consider variability in its setting of the MACT floor but did not consider all the sources of operational variability that could be reflected in the standards. EPA should include these other factors to develop more achievable standards.

[Footnote]

(11) See *Cement Kiln Recycling Coal. v. EPA*, 255 F.3d 855 (D.C. Cir. 2001).

(12) *Sierra Club v. EPA*, 167 F.3d 658, 665 (D.C. Cir. 1999).

(13) *Nat'l Lime Ass'n v. EPA*, 627 F.2d 416, 443 (D.C. Cir. 1980).

Response: The EPA thanks the commenter for their support of accounting for variability in setting standards. The EPA agrees with the commenter's assertion that the solid fuel limits only represented testing variability and not operational variability. For this reason, EPA believes it is necessary to establish fuel variability factors (FVF) for the Hg and HCl limits for the solid fuel subcategory. The Hg and HCl MACT floor emission limitations in the final rule have each been multiplied by an FVF, which EPA believes fully accounts for operational variability.

Commenter Name: Stephen E. Woock

Commenter Affiliation: Weyerhaeuser Company

Document Control Number: EPA-HQ-OAR-2002-0058-3523-A1

Comment Excerpt Number: 9

Comment: This technical feasibility concern may be diminished if EPA adjusts its proposed solid fuel subcategory mercury limit based on fuel variability. We believe EPA may have inaccurately evaluated the re-proposed limit by failing to include the variability of the mercury in solid fuels combusted by individual units beyond the amounts present during the performance tests of the selected top performers. For example, at one of our mills the supplier specifications for delivered coal in April 2011 had a mean of 0.07 ppm with a 95% percentile of 0.13 ppm. This single example of nearly two-fold factor can translate directly to variations in emission levels over short periods of time and impact the ability to demonstrate compliance during performance tests where the margin of compliance is narrow due to technology concerns raised above. We refer EPA to the detailed AF&PA et al. and CIBO comments which address incorporating a fuel variability factor (FVF) to ensure the limits are achievable and the NCASI comments which highlight technical aspects of fuel variability factor approaches.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3508-A1, excerpt 5.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 69

Comment: Another issue to consider is whether the fuel quality among top performers is representative of the fuel quality among all units, i.e., whether the range of pollutant concentrations observed within the fuels in the top performers encompasses the range of "all possible" concentrations. Since the MACT floor units are such a small percentage of the total number of boilers in that subcategory, it is unlikely that the range is fully represented. This would be an important factor to ensure that the standards being developed are achievable, especially in the case of "fuel-based pollutants."

Response: See the response to comment EPA-HQ-OAR-2002-0058-3508-A1, excerpt 5.

Commenter Name: Randall D. Quintrell

Commenter Affiliation: Georgia Paper & Forest Products Association

Document Control Number: EPA-HQ-OAR-2002-0058-3451-A1

Comment Excerpt Number: 3

Comment: The proposed emission limits for mercury and hydrogen chloride do not reflect the effects of fuel variability within each type of fuel class, a factor that is often beyond the control of the operator. Fuel supply availability and cost are important factors that EPA has not appropriately factored in to these decisions, leaving boiler operators in an untenable situation when fuel variability could cause non-compliance, even though the required technology has been installed.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3508-A1, excerpt 5.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 26

Comment: Fuel flexibility is an important factor in the operation of many industrial facilities, and fuel cost is usually one of the top three costs of doing business. Many facilities have committed to a single solid fuel, such as coal, but other facilities burn a mixture of fuels. EPA should set limits for HCl and Hg for solid fuel-fired units that ensure the maximum number of sources can achieve the limits and that do not disadvantage users of any one particular fuel.

EPA has the discretion and should include a fuel variability factor in the MACT floor analysis for the solid fuel subcategory HCl and Hg limits so fuel pollutant content variability among the top performers is adequately considered. This approach would make achievability of these standards more viable, while reflecting the real world operational and fuel variability that boilers experience.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3508-A1, excerpt 5.

Commenter Name: Lorraine Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1
Comment Excerpt Number: 22

Comment: The Application of Some Fuel Variability Factors (FVFs) May Be Appropriate for HCl and Hg Emission Limits Once EPA Establishes Separate Subcategories for Coal and Biomass Boilers

In the MACT Floor Memos for both the Final Boiler Rule⁸ and the Reconsideration Proposal⁹, EPA made the following statement:

For existing solid fuel units, EPA reviewed the fuel variability in the UPL calculations prior to multiplying the results by the FVF. In the case of the solid fuel subcategory the fuels used in the top performing boilers varied widely, including coal, petroleum coke, tire-derived fuel, as well as several types of biomass fuel. Based on the heterogeneous make up of the best performing units, we determined that the UPL calculation alone considered sufficient variability in fuel types from best performing units and it was unnecessary to incorporate additional fuel variability through the use of a FVF.

Once EPA separates biomass and coal units into subcategories, it needs to re-evaluate the variability represented by the upper prediction limit (UPL) calculation. It should follow the procedures from the Final Boiler Rule MACT Floor Memo where both the recommended (combined solid units) and the alternative (separate coal and biomass) datasets are evaluated and determine whether or not FVFs should be applied. What EPA will find is that the datasets have significantly less heterogeneity and FVFs may be appropriate. [Footnote 8: EPA-HQ-OAR-2002-0058-3273]

[Footnote 9: EPA-HQ-OAR-2002-0058-3387]

Response: For the reasons specified in the preamble to the March 21, 2011 final rule notice (76 FR 15608), EPA has retained a solid fuel subcategory for HCl and Hg. However, EPA has implemented a fuel variability factor (FVF) for the HCl and Hg solid fuel limits for the final rule. For discussion of the solid fuel FVF, please see comment EPA-HQ-OAR-2002-0058-3508-A1, excerpt 5.

Commenter Name: Steve Gossett
Commenter Affiliation: Eastman Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3669-A2
Comment Excerpt Number: 10

Comment: Application of some Fuel Variability Factors (FVFs) may be appropriate for HCl and Hg emission limits once EPA establishes subcategories for coal and biomass boilers.

Discussion: In the MACT Floor Memos for both the final rule (memo dated January 4, 2011) and the reconsideration proposal (memo dated November 2011), EPA made the following statement:

For existing solid fuel units, EPA reviewed the fuel variability in the UPL calculations prior to multiplying the results by the FVF. In the case of the solid fuel subcategory the fuels used in the top performing boilers varied widely, including coal, petroleum coke, tire-derived fuel, as well as several types of biomass fuel. Based on the heterogeneous make up of the best performing units, we determined that the UPL calculation alone considered sufficient variability in fuel types from best performing units and it was unnecessary to incorporate additional fuel variability through the use of a FVF.

Once EPA separates biomass and coal units into subcategories, it needs to re-evaluate the variability represented by the UPL calculation. It should follow the procedures from the final rule MACT Floor Memo where both the recommended (combined solid units) and the alternative (separate coal and biomass datasets) are evaluated and determine whether or not FVFs should be applied. What EPA will find is that the datasets have significantly less heterogeneity and FVFs may be appropriate.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 22.

Commenter Name: Mary Sullivan Douglas

Commenter Affiliation: National Association of Clean Air Agencies (NACAA)

Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1

Comment Excerpt Number: 24

Comment: EPA takes the result of its 99th percentile UPL calculation and applies a second variability factor, what it styles as a “fuel variability factor,” to determine the overall variability to apply to a “best performing unit.” This constitutes double counting and should not be permitted. This double counting occurs because fuel variability is part of, and in many instances the major part of, the test-to-test variability that forms the basis of the 99th percentile UPL calculation. In the case of the liquid-fired Hg limit, EPA applied a “Fuel Variability Factor” to the 99th percentile UPL to further increase its proposed MACT floor to 2.6×10^{-5} lb/MMBtu. EPA applies this factor, not because the data respecting the Hg fuel variability of the best units showed that the variability was too large, but because it was, in EPA’s view, too small. EPA acknowledged that, for solid-fuel units, the variability in the amount of a pollutant in the fuel would be reflected in the emissions performance of the units but decided that “[f]or existing and new liquid fuel units, the fuels making up the best performing units demonstrated less variability in their composition and type, and there were a smaller pool of available test runs. EPA determined that an additional fuel variability factor was necessary in these cases.” EPA’s added emission factor makes only a slight (5 percent) difference in that case, but, if applied to solid fuel-fired units, would increase the standard by an order of magnitude.²²

[Footnote]

(22) Memorandum, Eastern Research Group to Shrager, B, USEPA, *Revised MACT Floor Analysis (November 2011) for the Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants – Major Source*, November, 2011 (“MACT Floor Memo”) Appendix C-4-(a)(i). p. 7.

Response: EPA disagrees that the fuel variability factor (FVF) constitutes double-counting of variability. The 99% UPL accounts for testing variability, while the FVF accounts for

operational and fuel variability between sources. EPA believes both types of variability should be accounted for when establishing emissions standards.

Commenter Name: Mary Sullivan Douglas

Commenter Affiliation: National Association of Clean Air Agencies (NACAA)

Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1

Comment Excerpt Number: 8

Comment: EPA then multiplies these results by a fuel variability factor to establish the final number that it uses to calculate the floor. This fuel variability factor is also different for different units, and so, again, the unit with the lowest single test result is not necessarily the “best performer” as used in EPA’s calculations.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3525-A1, excerpt 24.

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 15

Comment: Not satisfied with grossly overstating sources’ actual emissions through its 99% UPL and treatment of non-detect levels, EPA also applies a second variability factor that it describes as a “fuel variability factor.” But any variability in sources’ emissions that is caused by variations in fuel is already accounted for – and indeed, grossly overstated – by the 99% UPL. Adding a second variability factor to account for variability that has already been accounted for once overstates variability and results in overestimates of individual sources’ performance and, therefore, yields floors that do not reflect the best sources’ performance. Remarkably, EPA adds a fuel variability factor where the data showing fuel variability is, in EPA’s opinion, too small. Inflating the alleged emissions achieved by sources based on alleged variability that the agency cannot even identify is arbitrary itself, and reveals that the agency is simply adjusting the numbers to reach more lenient standards that it evidently prefers to the standards required by the Clean Air Act.

Response: EPA disagrees that the fuel variability factor (FVF) constitutes double-counting of variability. In this case, we applied the UPL to assess source variability. Specifically, the MACT floor limit is an upper prediction limit (UPL) calculated with the Student’s t-test using the TINV function in Microsoft Excel®. The Student’s t-test has also been used in many other EPA rulemakings to account for variability. A prediction interval for a future observation is an interval that will, with a specified degree of confidence, contain the next (or some other pre-specified) randomly selected observation from a population. In other words, the prediction interval estimates what the upper bound of future values will be, based upon present or past background samples taken. The UPL consequently represents the value which we can expect the mean of future observations to fall below within a specified level of confidence, based upon the results of an independent sample from the same population. Therefore, if we were to randomly select a future test condition from any of these sources, we can be 99 percent confident that the reported level will fall at or below the UPL value. Use of the UPL is appropriate in this

rulemaking because it sets a limit any single or future source can meet based on the performance of the MACT floor sources data pool. This formula uses a pooled variance (in the s^2 term) that encompasses all the data-point to data-point variability of the best performing sources comprising the MACT floor pool for each HAP. EPA also received comments claiming that this final rule raises the (perceived) quandary voiced by Judge Williams in his concurring opinion in Brick MACT where an achieved level of performance for purposes of CAA section 112(d)(3) results in a standard which is unachievable under CAA section 112(d)(2) because it is too costly or not cost-effective. Brick MACT, 479 F. 3d at 884-85. EPA is of course mindful of the repeated admonitions from the D.C. Circuit that MACT floors must reflect achieved performance of the best performing units, that HAP content of process inputs (raw materials and fuels) must be accounted for in ascertaining sources' performance, and that EPA cannot consider costs in ascertaining the level of the MACT floor. See, e.g., Brick MACT, 479 F. 3d at 880-81, 882-83; NRDC v. EPA, 489 F. 3d 1364, 1376 (D.C. Cir. 2007) ("Plywood MACT"); see also Cement Kiln Recycling Coalition v. EPA, 255 F. 3d 855, 861-62 (D.C. Cir. 2001) ("achievability" requirement of CAA section 112 (d)(2) cannot override the requirement that floors be calculated on the basis of what best performers actually achieved). EPA is also mindful of the need to account for sources' variability (both due to control device performance and variability in inputs) in assessing sources' performance when developing technology-based standards. See, e.g., Mossville Environmental Action Now v. EPA, 370 F. 3d 1232, 1242 (D.C. Cir. 2004); National Lime I, 627 F. 2d 416,433-34(D.C. Cir. 1980). EPA has carefully developed data for each standard, assessing both technological controls and HAP inputs from fuel in doing so, to accurately measure both which performers are best and what their performance is.

The MACT floors reflect a reasonable estimate of what the best performing sources will achieve over time. Each of the floors considers the impact of non-technology factors, notably HAP inputs in fuels, on the source's emissions. For mercury and HCL, the standards reflect 30 days of data from the best performing sources for all fuel inputs (which was collected from boilers and process heaters as part of the ICR), reasonable estimates of control device performance, plus a reasonable statistical methodology to account for variability (including variability of HAP content from fuel inputs). The 30-day fuel variability data show that boiler performance for the source categories at issue (based only on short term stack test data) does not necessarily reflect the different fuel inputs that were used outside the short term sampling period. Therefore the short term stack test data alone are not necessarily indicative of long term emissions performance. Based on the 30 day fuel input data from the best performing sources, it was observed that the mercury and chlorine levels varied significantly at the best performing sources over the 30 day period. Fuels combusted within a short term three hour test would be expected to be fairly consistent in their levels of mercury and chlorine, but the 30 days of data provided by industry in response to EPA's ICR data collection show significant variations in levels of these pollutants from the fuel that is combusted by boilers and process heaters over longer periods of time. In light of this, we applied the fuel variability factor to reflect the variation of HAP from fuel inputs. The FVF accounts for fuel variability between sources using long term fuel measurement data that represent inherent natural variations in fuel usage at the best performing units over time. The FVF is the average of the individual FVF that were calculated for each best performing unit using the mercury and chlorine content of samples collected over a 30 day period. The FVF was used in conjunction with the 99% UPL to characterize long-term

variability due to technological controls and fuel characteristics. The results are MACT floors which reasonably estimate the performance over time of the best performing sources.

Commenter Name: Mary Sullivan Douglas

Commenter Affiliation: National Association of Clean Air Agencies (NACAA)

Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1

Comment Excerpt Number: 37

Comment: EPA has provided no rationale for selecting the maximum emission factor in a group of tests in developing its fuel variability factors. Other examples of an upward bias can be found in EPA's calculation process³⁷ including: (1) exclusion of test results where the result provided is "zero" or "non-detect," but the detection limit is not provided, and (2) failure to include homogeneous waste material combusted by some biomass boilers in the fuel variability analysis (EPA argued that such data should be excluded because it is not a representative material for other boilers in the biomass subcategory).

[Footnote]

(37) The rounding process employed by EPA can increase MACT floor results significantly. The other biases we mention are unlikely to have a large impact on the MACT floor. The use of log-normal statistical procedures may or may not result in lower MACT limits than would otherwise be the case, but is technically justified where nonnormal distributions are observed.

Response: The EPA did not select the maximum in developing the fuel variability factors. Given that the solid fuel category does exhibit some heterogeneous fuel make-up amongst the top performing units, the EPA adopted the average fuel variability ratio for each pollutant instead of the maximum fuel variability ratio. This average value was selected to not overestimate fuel variability for a subcategory that has a mix of biomass, coal, and other solid fossil stack test data factored into the 99% UPL calculations, but it recognizes that some additional fuel variability is present in the best performing units that may not be represented by the stack test data alone.

Commenter Name: Dirk J. Krouskop

Commenter Affiliation: MeadWestvaco Corporation (MWV)

Document Control Number: EPA-HQ-OAR-2002-0058-3493-A1

Comment Excerpt Number: 3

Comment: MWV believes that EPA has established a series of requirements that are more stringent than necessary to satisfy the requirements of the MACT floor which represents the average of the top 12 % in specific subcategories. EPA needs to take additional steps to better account for performance variability of the identified top performers. This can be accomplished by considering fuel variability in setting the proposed emission limits. EPA has not included fuel variability factors for HCl or mercury for the solid fuel subcategory but has included a fuel factor for HCl and mercury in the liquid unit subcategory. EPA should collect fuel variability data for all top performers to ensure that the analysis is complete. EPA should also determine whether the fuel variability adjustment adequately captures the variability of all types of fuels that could be fired by boilers in each of the subcategories. Variability will lead to more appropriate standards

for both new and existing units. A more complete evaluation of variability will lead to more achievable emission levels while providing adequate protection to health and the environment.

Response: The EPA agrees with the commenter's assertion that fuel variability should apply to all regulated fuel subcategories, including solid fuel. The Hg and HCl MACT floor emission limitations in the final rule have each been multiplied by an FVF, which EPA believes fully accounts for operational variability. EPA would have incorporated any new fuel variability data received during the public comment period into the FVF analysis, but no new data were received.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 66

Comment: The solid fuel subcategory HCl and Hg limits must incorporate a fuel variability factor (FVF) to ensure the limits are truly achievable and account for variations in fuel pollutant content across the fuels burned by the top performing units that make up the solid fuel subcategory floor.

While EPA has included an FVF for Hg and HCl for the liquid fuel subcategory MACT floors, a similar analysis has not been included for the solid fuel category MACT floors in the re-proposal. As outlined in the ERG MACT floor memo, in the case of the solid fuel subcategory, EPA concluded that the range of fuels used in the top performing boilers varied widely and included coal, petroleum coke, tire-derived fuel, as well as several types of biomass fuel. Given this heterogeneous make-up of the best performing units, EPA concluded that the UPL calculation alone represented sufficient fuel variability and that it was unnecessary to incorporate additional fuel variability through the use of a FVF. We do not believe that fuel heterogeneity, by itself, accounts for the range of pollutant concentrations that could exist within those fuels. For instance, the range of pollutant concentrations observed within these fuels during the performance tests may not be representative of the range of "all possible" concentrations. Furthermore, "intra-unit" variability in fuel pollutant concentrations may not have been addressed adequately by considering only the limited performance tests. For these reasons, we recommend the following:

- EPA should collect additional fuel variability data for all top performers to ensure that the fuel analysis data covers the entire range of possible concentrations.
- EPA should also determine whether the fuel variability adjustment adequately captures the variability of all types of fuels that could be fired by boilers in each of the subcategories. As EPA has previously stated, fuel switching is not an appropriate mandate for this rule, so the limits should be achievable for boilers burning the full ranges of coals and fuel oils.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3493-A1, excerpt 3.

Commenter Name: Douglas A. McWilliams

Commenter Affiliation: American Municipal Power

Document Control Number: EPA-HQ-OAR-2002-0058-3685-A2

Comment Excerpt Number: 31

Comment: EPA also failed to include a fuel variability factor for HCl or Hg for solid fuel-fired units. EPA states that this was unnecessary due to the variety of fuels represented in the top 12 percent, but this ignores the purpose of the variability analysis: to ensure that emission limits are achievable in practice. Each of the fuels represented in the top 12 percent is variable in itself, and EPA has not accounted for this in its analysis. Capturing variability is particularly important for coal-fired units, because variability in coal quality occurs within individual seams and within one unit's supply, which may come from different sources. EPA's testing did not account for this difference in fuel quality. However, EPA may look to other sources for emissions information related to the variability of coal content among coal rank and regions and apply this information to improve the variability data for the top performers.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3493-A1, excerpt 3.

Commenter Name: Ashok K. Jain

Commenter Affiliation: National Council for Air and Stream Improvement, Inc. (NCASI)

Document Control Number: EPA-HQ-OAR-2002-0058-3505-A1

Comment Excerpt Number: 15

Comment: NCASI agrees with EPA's rationale regarding the applicability and use of Fuel Variability Factors (FVF) to better account for changes in Hg and HCl concentrations in fuels over time. This rationale is especially pertinent given that Hg and HCl are classified as "fuel-based pollutants" in this rulemaking. However, EPA has not considered the use of FVFs in proposing the emission limits for Hg and HCl in the solid fuel subcategory. As outlined in the Singleton Memorandum (Singleton 2011), in the case of the solid fuel subcategory, EPA concluded that the range of fuels used in the top performing boilers varied widely and included coal, petroleum coke, tire-derived fuel, as well as several types of biomass fuel. Given this heterogeneous make-up of best performers, EPA concluded that the UPL calculation adequately represented fuel variability and that it was unnecessary to incorporate additional fuel variability through the use of a FVF.

It is true that performance tests, conducted across all best performers in the fuel category, may indeed reflect emissions under a wide range of possible pollutant concentrations in fuels. Additionally, the UPL calculations take into account "intra-unit" emission and test-run variability. However, they do not directly account for unit-specific variability in fuel pollutant concentrations nor do they reflect the range of pollutant concentrations that could exist within these fuels. Any representation of these ranges would be purely coincidental and dictated by the prevailing pollutant concentrations during the performance tests. The following points are pertinent:

Across all best performing facilities, the range of pollutant concentrations observed in the fuels during the course of the performance tests may not encompass the range of "all possible" concentrations that could be measured in these fuels at these locations. For any given best performer, the range of pollutant concentrations observed in the fuels during the course of

limited performance tests may not encompass the range of “all possible” concentrations that could be measured at that facility.

This variability in pollutant concentrations can be adequately accounted for only by quantifying FVFs for each source that is a best performer. This is especially true for fuel-based pollutants. For these reasons, we recommend that the EPA should collect additional fuel variability data for all top performers to ensure that the fuel analysis data covers the entire range of possible concentrations.

Response: EPA agrees with the commenter. A fuel variability factor (FVF) has been applied to the solid fuel subcategory MACT floor emission limitations in the final rule. Additional fuel variability data were welcomed during the public comment period, but no data were received.

Commenter Name: Ashok K. Jain

Commenter Affiliation: National Council for Air and Stream Improvement, Inc. (NCASI)

Document Control Number: EPA-HQ-OAR-2002-0058-3505-A1

Comment Excerpt Number: 16

Comment: NCASI has carried out an analysis of Fuel Variability Data among the top performing boilers in the solid fuel subcategory using the procedures laid out in the Singleton Memorandum (Singleton 2011). The *fuelspecific* approach outlined in the Singleton memo involves the following:

- Variability ratios are calculated for all top performers in the solid fuel subcategory. The entire dataset of ratios, calculated for every fuel analysis data point reported for all best performers, is assumed to be normally distributed.
- Outliers from this dataset of ratios are removed by applying the empirical rule to the entire dataset and removing all ratios that do not fall within three (3) standard deviations of the mean of all the ratios for the solid fuel subcategory.
- After the outliers are removed, the maximum ratio in the new dataset becomes the FVF for the solid fuel subcategory.

In the original proposal, this outlier analysis was carried out both on a *fuel-specific basis* (all calculated ratios from all best performers in the solid fuel subcategory combined into one dataset) and a *unit-specific basis* (outlier analysis carried out on variability ratios calculated for each unit on the best performer list).

However, the *fuel-specific basis* was concluded to be more appropriate for this analysis. The reasoning (also provided in the Singleton Memo) was that the fuel variability is based on a range of fuel types identified to be from a set of best performing units in a subcategory and not for fuels specific to any single unit.

Hg and HCl FVFs for the solid fuel subcategory, calculated using the approach detailed above, are provided in the Table below. [See submittal for table] Additionally, the variability ratios among the best performers in the biomass subcategory have also been analyzed in order to calculate Hg and HCl FVFs.

The above analysis, carried out using the methodology outlined by EPA in the original rulemaking, indicates that the variability in Hg and HCl concentrations in the fuel is an important component and should be incorporated into the applicable emission limits.

Response: EPA agrees with the commenter's assertion that fuel variability factors (FVF) should be applied to the Hg and HCl emission limitations for the solid fuel subcategory. In the final rule, the Hg and HCl MACT floor emission limits for solid fuels have been multiplied by an FVF.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 67

Comment: NCASI conducted an analysis of fuel variability data among the top performing boilers in the solid fuel subcategory using the procedures laid out in the ERG MACT floor memo. This procedure (a) calculates variability ratios for all top performers in the solid fuel subcategory and (b) utilizes the empirical rule, on all calculated ratios within the solid fuel subcategory, to identify and remove potential outliers. As outlined in the ERG MACT Floor Memo, this outlier analysis was carried out both on a fuel-specific basis (all calculated ratios from best performers in the solid fuel subcategory combined into one dataset) and a unit-specific basis (outlier analysis carried out on variability ratios calculated for each unit on the best performer list). However, the fuel-specific basis was concluded to be more appropriate for this analysis. The FVFs calculated using this approach are provided in the table below and demonstrate that both biomass and coal have a significant amount of variability in chloride and mercury content. The data show that an adjustment of the calculated 99 UPLs by at least a factor of 2 is warranted.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3505-A1, excerpt 16.

Commenter Name: Ashok K. Jain

Commenter Affiliation: National Council for Air and Stream Improvement, Inc. (NCASI)

Document Control Number: EPA-HQ-OAR-2002-0058-3505-A1

Comment Excerpt Number: 17

Comment: NCASI has carried out the above analysis in order to be consistent with the approach outlined in the Singleton memo. However, it is worthwhile to point out that the approach has its limitations as it pertains to outlier identification and elimination. The following are worth identifying:

- The dataset of variability ratios associated with all best performers in the subcategory is frequently not normally distributed. The empirical rule may therefore not be applicable for outlier identification (eliminating outlier values that are not within three SDs of the mean of all computed ratios).
- Two key criteria for confirming outliers are (1) does a graphical observation of the data including the outlier(s) confirm that it is an outlier? and (2) when data normality is assumed to identify outliers, are the remaining data without the outlier(s) normally distributed? On

both these points, a review of the Hg and HCl FVFs for the solid fuel subcategory shows that these criteria were not satisfied.

- The empirical rule, when applied on a *fuel-specific basis* (on the larger dataset of all best performers), may incorrectly identify some variability ratios as outliers. For instance, if a subset of best performing units have a higher level of variability in fuel pollutant concentration, this information may be lost as part of the *fuel-specific* outlier identification procedure. In such cases, the empirical rule may also have to be applied on a *unit-specific basis* to reconfirm outliers.

Outlier elimination using the empirical rule on a *fuel-specific basis* therefore has the potential to *underestimate* the FVFs. Given the above limitations, it is also worthwhile to consider alternative approaches to calculating FVFs and eliminating the limitations of an unconfirmed outlier analysis. These include:

- Estimating either the 90 or 95% UPL of all variability ratios in a subcategory, using a methodology consistent with the type of data distribution, or Employing non-parametric statistics (e.g., the 90 or 95% Chebyshev UPLs) when the dataset is not represented by any particular type of distribution.

Response: Based on our consideration of the suggested alternative approaches, we have not changed our approach to estimating FVF.

102D. MACT Floor Methodology: Minimum CO Levels

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 33

Comment: EPA itself has already reached the conclusion that forcing CO emissions below 100 ppm does not force organic HAP emissions to ultra-low levels in the Hazardous Waste Combustor NESHAP rulemaking. As the Agency states at 70 FR 59462 (October 12, 2005):

"We explained at proposal why the carbon monoxide standard of 100 ppmv and the hydrocarbon standard of 10 ppmv are appropriate floors. See 69 FR at 21282. The floor level for carbon monoxide of 100 ppmv is a currently enforceable Federal standard. Although some sources are achieving carbon monoxide levels below 100 ppmv, it is not appropriate to establish a lower floor level because carbon monoxide is a conservative surrogate for organic HAP. Organic HAP emissions may or may not be substantial at carbon monoxide levels greater than 100 ppmv, and are extremely low when sources operate under the good combustion conditions required to achieve carbon monoxide levels in the range of zero to 100 ppmv. (See also the discussion below regarding the progression of hydrocarbon oxidation to carbon dioxide and water). As such, lowering the carbon monoxide floor below 100 ppmv may not provide significant reductions in organic HAP emissions. Moreover, it would be inappropriate to establish the floor blindly using a mathematical approach—the average emissions for the best performing sources—because the best performing sources may not be able to replicate their emission levels (and other sources may not be able to duplicate those emission levels) using the exact types of good combustion

practices they used during the compliance test documented in our data base. This is because there are myriad factors that affect combustion efficiency and, subsequently, carbon monoxide emissions. Extremely low carbon monoxide emissions cannot be assured by controlling only one or two operating parameters."

CIBO agrees that CO is an appropriate surrogate for organic HAP, but we believe HAP emissions are minimized at levels well above the 3 to 10 ppm CO limits proposed for Gas 2 and liquid boilers. At CO levels below about 100 ppm, differences in organic HAP emissions are negligible. Where achievable emission limitations for organic HAP that properly reflect source category and unit variability are derivable from representative data, CO should continue to be used as the compliance surrogate for organic HAP. However, the CO limits should reflect the fact that the organic HAP concentration becomes insensitive to CO level below some value (e.g., 100 ppm).

For coal units, EPA reached a similar conclusion in the recently finalized MATS rule. Many coal-fired boilers emit CO in the range of 50-100 ppm while emitting less than 1 ppm THC. This fact is supported by EPA's boiler ICR databases. Thus, a boiler required to reduce CO to meet the numerical standard could install an oxidation catalyst with no evidence that VOC will be reduced since there is little emitted to begin with.

Response: We agree that CO is an appropriate surrogate for organic HAP. Based on the concern raised by the commenter, and others, that there is a CO level below which organic HAP emissions/destruction are negligible, we conducted an evaluation to determine whether there is a minimum CO level below which there is no further benefit in organic HAP reduction/destruction. We first evaluated the relationship between CO and formaldehyde using the available data obtained during the rulemaking. Formaldehyde was selected as the basis of the CO-organic HAP comparison because it was the most prevalent organic HAP in the emission database and a large number of paired tests existed for CO and formaldehyde. A plot of the paired data showing the relationship between CO and formaldehyde emissions confirms that CO is an appropriate surrogate for organic HAP. The plot shows decreasing formaldehyde emissions with decreasing CO emissions down to CO levels around 300 ppm. The relationship between formaldehyde and CO emissions at levels below 150 ppm, however, suggested that at these low CO levels, CO is not a good surrogate for formaldehyde emissions/destruction because the overall CO-formaldehyde data show either no further reduction or an increase in formaldehyde emissions. In assessing the correlation between CO and formaldehyde, formaldehyde levels appear at their lowest when CO emissions are in the range of 130 to 300 ppm. At CO levels lower than 130 ppm, formaldehyde emissions appear to increase. The lower end of this range, 130 ppm, was therefore used as the minimum CO emission limit for a subcategory if the calculated 99% UPL was less than 130 ppm.

Minimum CO emission limits were assigned to the coal fluidized bed, pulverized coal, heavy liquid, light liquid, non-continental liquid, and gas 2 subcategories for both existing and new sources. The new source coal stoker CO emission limit was also assigned to the minimum value of 130 ppm.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 38

Comment: It is well established that CO is harder to combust than the volatile HAPs that might be emitted by industrial boilers and other similar combustion sources. In this respect, CO actually is a conservative surrogate for volatile HAPs from industrial boilers because measured CO emissions can rise up to a certain point without a corresponding increase in volatile HAP emissions. As mentioned in the previous section, studies have shown that volatile HAP emissions remain extremely low at measured CO levels of up to about 100 ppm.

Thus, while it is certainly possible to reliably measure CO to levels well below 100 ppm, EPA would be justified in setting the IB MACT CO limits at no lower than 100 ppm because lower values would not result in demonstrably lower volatile HAP emissions. This squares with DC Circuit precedent on the use of surrogates because the court has held that EPA may use surrogates as long as the Agency can establish a necessary relationship between emissions of the surrogate and emissions of the underlying HAPs. There is nothing in that precedent that demands that the relationship must be linear. In the case of CO and volatile HAP emissions from industrial boilers, credible data show that the relationship is highly nonlinear at low levels. It would be rational and in keeping with court precedent for EPA to set a CO standard that reflects this nonlinear relationship.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 33.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 41

Comment: Carbon monoxide is the most common product of incomplete combustion (PIC), and because of its associated chemical kinetics, is one of the most difficult PICs to oxidize completely. As such, CO emissions have historically been used as an indicator of the quality of the combustion process. The concept is that low CO emissions would equate to negligible emissions of other organic compounds. While this is true in general, the mechanisms by which CO is formed and destroyed in the combustion process are different than for other organics.³³ As such, in cases where other organic compounds have been completely oxidized, CO concentrations may still be elevated. While the tendency is to think that further reductions in CO emissions will improve the quality of the combustion, and in turn minimize emissions of other organic compounds, this is not necessarily true. Instead, forcing CO emissions lower and lower ends up over- constraining the combustion process, producing negative impacts on other air quality concerns, such as NOX emissions, without documented improvements in emissions of organics past a certain level of CO emissions reduction. Because the chemical kinetics make CO far more difficult to oxidize than other organic compounds, it is not necessary to drive CO emissions toward zero to obtain a corresponding minimization of organic emissions.

[Footnote 33: For example, we understand conversion of CO to CO₂ occurs at much higher temperatures than does oxidation of C (in coal or complex organics) or CH₄. CH₄ may burn at around 500 degrees F and carbon in coal at around 800 to 1000 degrees F, but CO converts most

readily around 1800 degrees F. CO as an intermediary in a flame zone likely will see temperatures in excess of 3000 degrees F and convert readily, while CO that carries from the flame zone (such as in the vortex adjacent to pulverized coal burner tips) to near the furnace wall at about 600 degrees would not oxidize but would rise along the furnace wall, never seeing sufficient temperature to ignite and exit as CO in the fuel gas. This is a primary phenomenon contributing to CO emissions levels in the 0 to 100 ppm range. Low loads and transient loads sub-optimize the time, temperature, and turbulence factors contributing further to un-combusted CO. These operational realities have less influence on organics than on CO because of the thermodynamic properties outlined.]

Response: See the response to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 33.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 51

Comment: EPA has justifiably used a CO standard as a proxy for organic destruction for over 20 years. However, it is well established that CO is harder to combust than the volatile HAPs that might be emitted by industrial boilers and other similar combustion sources. In this respect, CO actually is a conservative surrogate for volatile HAPs from industrial boilers because measured CO emissions can increase to a certain point without a corresponding increase in volatile HAP emissions. As mentioned in the previous section, studies have shown that volatile HAP emissions remain extremely low at measured CO levels of up to about 100 ppm.

The first EPA regulation to set a carbon monoxide (CO) standard for combustion was the "Burning of Hazardous Waste in Boilers and Industrial Furnaces" (56 Fed. Reg. 7134, February 21, 1991) under the Resource Conservation and Recovery Act (RCRA).

In that rule EPA set a CO standard of 100 ppmv. EPA chose that limit because their research indicated that while CO was a good surrogate for the destruction of organics, the validity of that surrogacy broke down at CO levels of approximately 400 ppmv. Based on EPA's authority under RCRA to establish standards that are protective of human health and the environment, the Agency established a 100 ppmv standard as protective.

The Agency later justifies a 100 ppmv standard at 70 Fed. Reg. 59462 (October 12, 2005) for the hazardous waste combustion NESHAP.

Thus, while it is certainly possible to reliably measure CO to levels well below 100 ppm, EPA would be justified in setting the Industrial Boiler MACT CO limits for fossil fuel-fired units no lower than 100 ppm because lower values would not result in demonstrably lower volatile HAP emissions but will create intractable compliance problems. This squares with DC Circuit precedent on the use of surrogates because the court has held that EPA may use surrogates as long as the Agency can establish a necessary relationship between emissions of the surrogate and emissions of the underlying HAPs. There is nothing in that precedent that demands that the relationship must be linear. In the case of CO and volatile HAP emissions from boilers, credible data show that the relationship is highly nonlinear at low levels. It would be rational and in

keeping with court precedent for EPA to set a CO standard that reflects this nonlinear relationship.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 33.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 30

Comment: Strict CO levels will not result in greater reduction of emissions of other organic compounds. CIBO has heard from vendors that they cannot guarantee many of the coal, liquid, and gas CO limits. In addition, some of our members with top performing units equipped with sophisticated combustion control like over-fired air, cannot say with certainty that they will meet the limits 100% of the time. CO varies significantly with load and fuel quality to the point that some of the units EPA is relying on to set the MACT floors cannot comply all year round.

Carbon monoxide is the most common product of incomplete combustion (PIC), and because of its associated chemical kinetics, is one of the most difficult PICs to oxidize completely. As such, CO emissions have historically been used as an indicator of the quality of the combustion process. The concept is that low CO emissions equate to low emissions of other organic compounds. While this is true in general, the mechanisms by which CO is formed and destroyed in the combustion process are different than for other organics. As such, in cases where other organic compounds have been completely oxidized, CO concentrations may still be elevated. While the tendency is to think that further reductions in CO emissions will improve the quality of the combustion, and in turn minimize emissions of other organic compounds, this is not necessarily true. Instead, forcing CO emissions lower and lower ends up over-constraining the combustion process, resulting in other air quality concerns, without achieving corresponding reductions in emissions of organics.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 33.

Commenter Name: Melvin E. Keener

Commenter Affiliation: Coalition for Responsible Waste Incineration (CRWI)

Document Control Number: EPA-HQ-OAR-2002-0058-3454-A1

Comment Excerpt Number: 1

Comment: Based on EPA research, the Agency cannot justify setting a MACT-floor emission standard for CO at a level less than approximately 400 ppmv.

In the proposed rule, EPA offers some changes to the CO standard that is being used as a surrogate for organic HAP emissions and proposes a second, alternative CO standard based on CO CEMS data. 76 Fed. Reg. at 80,611, and 80,614. As the Agency knows, based on D.C. Circuit Court of Appeals precedent, EPA may use non-HAP surrogates as long as the Agency can establish a necessary relationship between emissions of the surrogate and emissions of the underlying HAPs. EPA has justifiably used a CO standard as a proxy for organic destruction for over 20 years.

The first EPA regulation to set a carbon monoxide (CO) standard for combustion was the "Burning of Hazardous Waste in Boilers and Industrial Furnaces" (56 Fed. Reg. 7134, February 21, 1991) under the Resource Conservation and Recovery Act (RCRA). In that rule EPA set a CO standard of 100 ppmv. EPA chose that limit because their research indicated that while CO was a good surrogate for the destruction of organics, the validity of that surrogacy broke down at CO levels of approximately 400 ppmv. Based on RCRA's authority to establish standards that are protective of human health and the environment, EPA established a 100 ppmv standard as protective.

Response: We disagree that the Agency cannot justify setting a MACT floor emission standard for CO at a level below 400 ppmv. We do agree that CO is an apparent surrogate for organic HAP and, based on analysis of paired CO-formaldehyde data, there appears to be a CO threshold level which varies depending on boiler type and fuel but these levels are below 400 ppmv. See the response to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 33 for a discussion on establishing minimum CO emission limits.

Commenter Name: Melvin E. Keener

Commenter Affiliation: Coalition for Responsible Waste Incineration (CRWI)

Document Control Number: EPA-HQ-OAR-2002-0058-3454-A1

Comment Excerpt Number: 2

Comment: As the Agency knows, the first stage of thermal decomposition of organic compounds is to form smaller organic compounds (commonly called products of incomplete combustion or PICs). These PICs rapidly decompose to CO – a non-HAP organic not subject to regulation under the CAA MACT program. The second stage of combustion is to oxidize CO to CO₂. The CO to CO₂ step is the rate controlling step because CO is more difficult to oxidize than the other intermediate products of combustion. Given enough time under steady state conditions, all measurable amounts of the organics are destroyed and the CO and CO₂ come into equilibrium. The levels of CO at this equilibrium point depend upon the temperature and the amount of excess air in the combustion chamber. However, since conditions in a combustor are never in equilibrium because additional fuels are being added and gases are being exhausted, the Agency had to decide what levels of CO will guarantee that the organics have been destroyed and they are no longer a threat to human health and the environment – the primary regulatory question for RCRA regulation.

EPA attempted to answer this question in a series of studies to support the BIF rule. The Agency found that there was a correlation between the destruction removal efficiency of organics in the combustion process and CO above 400 ppmv but below this value, the relationship between CO and destruction of organics becomes more complicated. This makes sense since the rate limiting step is not the destruction of hydrocarbon but the oxidation of CO to CO₂. This is illustrated by data comparing benzene emissions to CO concentration (data from Graham, J.L., D.L. Hall, and B. Dellinger, "Laboratory Investigations of Thermal Degradation of Mixtures of Hazardous Organic Compounds," *Envi. Sci. Technol.*, Vol. 20, No. 7, pp 703-710, July 1988, cited in "Guidance on PIC Controls for Hazardous Waste Incinerators," Volume 5 of the Hazardous Waste Incineration Series, EPA/530-SW-90-040, April 1990). This graph [see EPA-HQ-OAR-2002-0058-3454-A2.pdf] shows that the below about 400 ppmv CO, the benzene concentrations are essentially flat and at a very low concentrations. Above these values, the benzene

concentrations may be higher. EPA concluded from this information that CO was a conservative indicator for organics – an important technical policy decision because it meant that below a certain level of CO, one can be assured that organic destruction is adequate. Complete destruction may occur above that level but it is not guaranteed. To add an additional level of safety to this conservative estimate, the Agency chose to set the CO standard at 100 ppmv. From the data, it can be seen that the Agency could just have well selected 200 ppmv or any value up to about 400 ppmv.

Response: See the responses to comments EPA-HQ-OAR-2002-0058-3454-A1, excerpt 1 and EPA-HQ-OAR-2002-0058-3534-A1, excerpt 33.

Commenter Name: Melvin E. Keener

Commenter Affiliation: Coalition for Responsible Waste Incineration (CRWI)

Document Control Number: EPA-HQ-OAR-2002-0058-3454-A1

Comment Excerpt Number: 3

Comment: In the MACT program, EPA is charged with the responsibility to develop emission standards that reflect the maximum degree of reduction in emissions of hazardous air pollutants being achieved by the best performers. According to EPA studies, therefore, all facilities emitting less than 400 ppmv are best performers. There is no reason to distinguish between them. EPA understands this concept because in the boiler and CISWI ICR, the Agency states "Agency research suggests that at CO levels below 100 ppm, CO concentration is no longer an accurate indicator of organic HAP control." (ICR No. 2286.11, OMB Control No. 2060-0616).

CRWI asserts that requiring a combustor to operate below a specified threshold will not result in any additional destruction of organics because there is little or none left to destroy. Thus, EPA is not justified in lowering the CO level to lowest observed level. As a non-HAP surrogate, CO must be judged based on the relationship it has to the regulated HAP. According to EPA research, any combustor with CO emissions below 400 ppmv, has destroyed virtually all organics and should all be considered as top performers. Therefore, setting a CO standard below approximately 400 ppmv is unnecessary and unlawful.

Response: See responses to comments EPA-HQ-OAR-202-0058-3454-A1, excerpt 1 and EPA-HQ-OAR-2002-0058-3534-A1, excerpt 33.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 58

Comment: CO is not a reliable surrogate for organic HAP oxidation below 100 ppm and there is, therefore, no basis for establishing emission limitations below that level.

Carbon monoxide is the most common product of incomplete combustion (PIC), and because of its associated chemical kinetics, is one of the most difficult PICs to oxidize completely. Thus, CO emissions are often used as a surrogate for more easily oxidized species, such as organic

HAPs. However, at lower CO levels this association breaks down because once all of the organic compounds have been completely oxidized the CO concentration is no longer an indicator of organic HAP oxidation.

EPA itself has already reached this conclusion in the Hazardous Waste Combustor NESHAP rulemaking. As the Agency states at 70 FR 59462 (October 12, 2005):

We explained at proposal why the carbon monoxide standard of 100 ppmv and the hydrocarbon standard of 10 ppmv are appropriate floors. See 69 FR at 21282. The floor level for carbon monoxide of 100 ppmv is a currently enforceable Federal standard. Although some sources are achieving carbon monoxide levels below 100 ppmv, it is not appropriate to establish a lower floor level because carbon monoxide is a conservative surrogate for organic HAP. Organic HAP emissions may or may not be substantial at carbon monoxide levels greater than 100 ppmv, and are extremely low when sources operate under the good combustion conditions required to achieve carbon monoxide levels in the range of zero to 100 ppmv. (See also the discussion below regarding the progression of hydrocarbon oxidation to carbon dioxide and water). As such, lowering the carbon monoxide floor below 100 ppmv may not provide significant reductions in organic HAP emissions. Moreover, it would be inappropriate to establish the floor blindly using a mathematical approach—the average emissions for the best performing sources—because the best performing sources may not be able to replicate their emission levels (and other sources may not be able to duplicate those emission levels) using the exact types of good combustion practices they used during the compliance test documented in our data base. This is because there are myriad factors that affect combustion efficiency and, subsequently, carbon monoxide emissions. Extremely low carbon monoxide emissions cannot be assured by controlling only one or two operating parameters.

CO is an appropriate surrogate for organic HAP at higher CO levels and for fuels that could generate significant levels of organic HAP, but we believe HAP emissions are minimized at levels well above the 3 to 18 ppm CO limits proposed for Gas 2 and liquid boilers. At CO levels below about 100 ppm, differences in organic HAP emissions are negligible. Thus, the surrogacy argument is not valid below 100 ppm and EPA should not set a CO numerical emission limit below that level.

Response: We agree that the surrogacy argument appears to be not valid below some CO level which appears to be dependent on the boiler type and fuel. See the response to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 33 for further discussion on identifying and establishing minimum CO level..

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 32

Comment: Some boilers only produce significant CO when they are experiencing load variations. All of the testing that is being used to establish the floor was conducted at steady high load conditions. A boiler may have very low CO emissions at steady high load, but significant CO emissions as the load varies. As such, the CO data used to establish the floor may not be

representative of normal boiler operation and a low CO limit may not be achievable by even the top performers under all operating scenarios, including operation at loads less than 100%.

CIBO sought the input of a leading supplier of burners for gas- and liquid-fired boiler applications to determine what CO emission guarantees would be provided for their installations. For applications for Gas 1 category fuels, the CO emission guarantee is generally 50 ppmvd (@ 3% O₂). For ultra-low NO_x burner applications, the CO emissions often exceed 50 ppmvd up to 50% load. For liquid-fired applications, the supplier offers a CO emissions guarantee of 100 ppmvd (@ 3% O₂), for loads ranging from 25% to 100%. Gas 2 sources have a greater variety of emissions characteristics due to the differences in fuel composition, which makes control of excess air more difficult. Most of these other gases tend to be lower heating value than natural gas or refinery gas and burn at lower flame temperatures. They are also commonly limited on the pressure that is available, therefore there is not as much flexibility on how the gases are injected and mixed in the burner. With these factors the potential for CO emissions tends to be higher on these gases than for natural gas or refinery gas. The supplier's default CO guarantee is 400 ppmvd (@ 3% O₂) at loads from 25-100% for Gas 2 fuels. Given the right furnace conditions, the guarantee may be as low as 100 ppm. CO guarantees are only provided on a "steady state" basis, since as burners change load the fuel-air ratio changes until the controls can react and the system stabilizes. If a boiler is equipped with CEMS and operates in a load- following mode, the transient conditions may generate CO levels that would inflate the 30-day rolling average.

Response: EPA agrees with the commenter that boilers may exhibit relatively lower CO emissions during periods of steady high loads and that emissions testing is typically conducted during these periods. EPA has implemented minimum CO emission limits of 130 ppm for all subcategories for which the calculated 99% UPL is less than 130 ppm. The CO emission limit for existing Gas 2 boilers in the final rule is significantly less stringent than the proposed limit of 4 ppm, and EPA believes this mitigates any concerns with low CO emissions correlating to periods of steady high loads exhibited during emissions testing.

3F01. MACT Floor Results: Existing Solid

Commenter Name: Stephen E. Woock

Commenter Affiliation: Weyerhaeuser Company

Document Control Number: EPA-HQ-OAR-2002-0058-3523-A1

Comment Excerpt Number: 8

Comment: We believe the re-proposed mercury limit for existing units of 3.1 lbs/TBtu, which would be more stringent than that finalized in March 2011, may be unachievable for multi-fuel units that burn biomass and coal without substantially impacting coal use, in essence forcing fuel switching. Use of activated carbon to control mercury emissions is highly uncertain for this type unit given the existence of biomass char already present in the combustion chamber and flue gas and the presence of other acid gas control technology.

Response: EPA has recalculated the mercury emission limitation for boilers and process heaters in the solid fuel subcategory. The resultant emission limitation is less stringent than the limit in the March, 2011 final rule due to the number of best performing sources being reduced from 40 to 39. The permanent closure and reclassification of several sources led to fewer overall sources

with mercury testing data. The EPA ICR Database contains several tests reported as co-firing coal and biomass for which the 3-run average is demonstrating compliance with the mercury emission limitation for solid units. EPA does not agree that this emission limitation will substantially impact coal use or force fuel switching for multi-fuel units. EPA believes that the less stringent limit provides added flexibility to overcome the uncertainty of activated carbon injection when paired with acid gas control technology for these multi-fuel units.

3F03. MACT Floor Results: Existing Coal – Fluidized Bed

Commenter Name: Dell Majure

Commenter Affiliation: Kimberly-Clark Corp.

Document Control Number: EPA-HQ-OAR-2002-0058-3692-A2

Comment Excerpt Number: 3

Comment: The CO emission limit from stack tests for coal-fired FB boiler is 56 ppmv @ 3 % O₂ is derived from CO values from two boilers "IAADM CornProcessingCR" and "ILCornProductsInt" of which both fire bituminous coal. K-C believes that these boilers may not have a FBHE due to the coal sources in the area they are located. K-C has contacted these facilities to confirm this fact, but has not received a response.

There is a fundamental difference between the reference unit and K-C's FBHE boiler. The Chester FBHE boiler cannot operate firing coal with only 9 % ash content because there is not enough ash too facilitate the conductive heat exchange with the furnace tubes and FBHE. By comparison, the design for the K-C FB boiler with its integral FBHE design requires a minimum fuel ash content of 20 – 25 %. This demonstrates a fundamentally different design than a coal-fired FB without a FBHE.

Therefore, the boiler used to establish the CO CEM emission limit is not of the same design or CO emission rates as a coal-fired FB boiler with a FBHE. In addition, the same is true for the CO stack test emission limit assuming that those boilers do not have a FBHE.

Response: EPA agrees with the fundamental design differences between a traditional fluidized bed boiler and a fluidized bed with an integrated heat exchanger, and separate subcategories have been established for these differing designs. An integrated heat exchanger allows a fluidized bed boiler to combust lower-quality coal (i.e., coal with a lower heating value), producing different combustion-related HAP emission characteristics than a fluidized bed boiler without an integrated heat exchanger. The CO CEMS-based and CO stack test-based emission limits have been recalculated for each of these combustor designs.

Commenter Name: Mark D. Pettegrew

Commenter Affiliation: PolyOne Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3513-A1

Comment Excerpt Number: 1

Comment: In addition to supporting VI's comments, PolyOne Corporation provides its own comments. Our Henry, Illinois facility operates a fluidized bed coal fired boiler that was installed in the mid 1980s. The boiler design and installation was influenced by the state government of

Illinois, as an economic boost to the state economy. This fluidized boiler design was specified because it would allow an Illinois company to burn Illinois coal which is inherently higher in sulfur and chlorine content. EPA's proposed limits for hydrogen chloride (HCl) cannot be met by continuing to burn Illinois coal without installing an expensive emission control device to meet the limit, or retrofitting the boiler and sourcing non-local coal, adversely impacting reliability and cost of our fuel source. We ask that USEPA reconsider the limits for HCl which will permit the continued economic viability of local fuel for this boiler.

Response: The EPA notes that the commenter does not suggest that the boiler is designed in a manner that would prevent HCl controls from being installed on the unit. Instead the comment points to the cost of installing these controls. First, section 112(d) does not permit EPA to take cost into consideration when establishing MACT floor limits. Further, the EPA did not subcategorized boiler types according to the cost to control pollutants from each subcategory, but rather based on differences in the class, type, and size of units. The EPA has evaluated the HCl emissions from the best performing solid fuel boilers and has finalized the emission limits based on the data available to the EPA. The EPA has also incorporated a fuel variability factor for HCl at solid fuel boilers in response to comments to better address fuel variability among best performing units.

3F04. MACT Floor Results: Existing Coal – Pulverized Coal

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 46

Comment: EPA proposes to set the CO limit for pulverized coal (PC) boilers at 41 ppm based on 3-hour stack test data from only a small percentage of the population. Vendors will not guarantee this level of performance. There are 188 PC boilers in EPA's database, EPA collected CO stack test data for only 41 units and only 5 units set the floor. With a favorable coal fineness distribution and fairly steady, high-rate load a PC boiler could be optimized to a very low CO emission level (maybe even 41 ppm). This approach (but not necessarily the 41 ppm numerical limit) is good for units that are base loaded close to their maximum capacity rating. Load following ("swing") boilers will seldom achieve the combination of fuel fineness, air control, and flame shape required to produce these low CO emissions because the demand dynamics of the steam system won't allow the boiler controls to find the ideal conditions. Safe boiler operation dictates that anytime boiler load changes, the air supply leads on load increase and lags on load decrease.

This is to ensure that there is never a fuel-rich mixture being introduced into the furnace that could result in an explosion. This safety concern overrides any attempt by an O2 trim controller to drive the air supply to the absolute ideal concentration for both CO and NOX reduction as load changes. Fortunately, the primary CO three hour performance test and longer term average oxygen monitoring provision requirements work in harmony with this safety concern. Because oxygen increases will lead fuel increases in increasing load scenarios and fuel decreases will lead oxygen decreases in decreasing load scenarios, sufficient oxygen for good combustion and safety will always be present, even though CO may increase at low levels as noted earlier.

Response: The CO MACT floor emission limitations for all subcategories have been recalculated based on new data or corrected data since the December, 2011 proposed reconsideration of the rule. The Pulverized Coal CO emission limit is now less stringent than the limit in the proposed rule. Three of the five units comprising the top performing CO emitters for this subcategory were reported as load-following units, and the CO test averages for these units demonstrate compliance with the revised emission limitation. EPA therefore disagrees that load-following units will have difficulty demonstrating compliance with the CO emission limitation for this subcategory.

Commenter Name: Dirk J. Krouskop

Commenter Affiliation: MeadWestvaco Corporation (MWV)

Document Control Number: EPA-HQ-OAR-2002-0058-3493-A1

Comment Excerpt Number: 4

Comment: MWV believes that requirements for certain subcategories remain unachievable. Specifically, we are concerned that the carbon monoxide (CO) standards for pulverized coal boilers are not achievable for many units. MWV is concerned that EPA believes that compliance with these standards is largely a function of combustion only. While combustion is a major factor, these emissions are also a function of boiler geometry, size and residence time. MWV believes that it is possible to implement various control strategies and air system improvement which will lower CO emissions, but not to the levels EPA proposes. MWV believes that EPA should look more closely at either additional subcategories for coal fired units or, as described in other areas of these comments, account, more fully for variability.

Response: For a response on achievability of CO standards for existing pulverized coal boilers, see comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 46. Specifically for Pulverized Coal boilers, 70 percent of the units in this subcategory for which emissions data were provided demonstrated compliance with the emission limitation in at least one 3-run test (as seen in the memo titled "MACT Floor Analysis for the Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP" in the docket). Given the number of boilers that reported emissions in compliance with the emission limitation, EPA disagrees that control strategies will be unable to reduce CO emissions for other units and also disagrees that further subcategorization of Pulverized Coal boilers is warranted. The commenter provided no specific information to support any further subcategorization.

Commenter Name: Samuel H. Bruntz

Commenter Affiliation: Alcoa Power Generating, Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3755-A1

Comment Excerpt Number: 10

Comment: Alcoa - Warrick performed Method 10 tests on one of its pulverized coal industrial boilers pursuant to a Section 114 request. The test results indicated that, on the test day, the proposed short term limit was met. Those tests may not have reflected potential operating conditions, such as mills that may not have been operating at peak performance. In addition, at the time of the Section 114 tests, Alcoa-Warrick was not subject to Best Available Retrofit Technology (BART) requirements for NOx emissions from its industrial boilers. BART will

require compliance with a low NOx burner emission limit of 0.38 lb./mm Btu that becomes effective in 2013. Based on available information for these burners, Alcoa- Warrick projects that it will be unable to comply with the proposed CO emission limit for pulverized coal fired boilers, once it implements the changes needed to comply with the BART emission limit for NOx, and requests that the proposed emission limit be increased to 150 ppm.

Response: For a response on the general achievability of CO standards for existing pulverized coal boilers, see comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 46. The relationship between CO and NOx emissions for the top performing CO emitters was evaluated for each subcategory. The MACT floor emission limit for Pulverized Coal boilers is calculated from a mixture of tests which exhibit both high and low NOx emissions, and EPA believes the variability between these tests results in an appropriate emission limitation for the subcategory. Several Pulverized Coal boilers are demonstrating compliance with the CO emission limitation while simultaneously demonstrating compliance with the 0.38 lb/MMBtu BART requirement for NOx (see the memo titled "MACT Floor Analysis for the Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP" in the docket). EPA therefore disagrees that units will be unable to demonstrate compliance with both emission limitations.

Commenter Name: Robert Ellerhorst

Commenter Affiliation: Michigan State University

Document Control Number: EPA-HQ-OAR-2002-0058-3674-A2

Comment Excerpt Number: 2

Comment: Review of the boiler MACT survey database and specifically Appendix B-4b: Unit Rankings for CO from Pulverized Coal 9 /Solid Fossil Fuel Units (Recommended Option), leads MSU to believe that the units that were used to set the floor are not representative units for MSU's boilers. To begin, MSU's PC boilers are equipped with low nitrogen oxide (NOx) burners (LNBS) and selective non-catalytic reduction (SNCR) controls to comply with NOx standards during the ozone season. NOx and CO have an inverse relationship when it comes to combustion properties. By reducing NOx emissions through control, MSU's CO emissions are higher than units not equipped with similar control. Of the five (5) units used to set the MACT floor for pulverized coal (PC) boilers, only one (1), the highest emitting in the floor, is equipped with low NOx burners and none of the units have SNCR. Therefore, MSU's boilers are not similar to those used to set the floor.

Response: EPA evaluated the relationship between CO and NOx emissions for all top performers. The ratio of reported NOx to CO emissions for several of the top performers in the Pulverized Coal subcategory is on the same level as reported for the Michigan State University boilers (where NOx emissions are less than five times higher than CO emissions). The EPA disagrees with the commenter that the design of pollution control equipment such as low NOx burners and SNCR should influence the subcategories established under this rule.

Commenter Name: Robert Ellerhorst

Commenter Affiliation: Michigan State University

Document Control Number: EPA-HQ-OAR-2002-0058-3674-A2

Comment Excerpt Number: 3

Comment: When the limitations were set in this proposed reconsidered rule, they were set for units greater than or less than 250 million British thermal units per hour (MMBtu/hr) of heat input. Review of Appendix B-4b, shows that the second lowest emitting source operates at 163 MMBtu/hr and the 6th ranked unit operates at 209 MMBtu/hr. MSU's boilers are all rated above the 250 MMBtu/hr threshold and should not be required to meet the same emission threshold that is met by smaller units.

Response: The MACT floor emission limitations for all subcategories have been revised since the December, 2011 proposed reconsideration of the rule. For the CO MACT floor emission limit for Pulverized Coal units, three of the 5 units comprising the top 12 percent have a maximum rated heat input capacity of greater than 250 MMBtu per hour. The remaining two units have a capacity below 100 MMBtu per hour. EPA believes that the large size range of the units comprising the top 12 percent mitigates the commenter's concerns.

For response to issues with NO_x control differences between MSU boilers and other top performing pulverized coal boilers, see comment EPA-HQ-OAR-2002-0058-3674-A2, excerpt 2.

Commenter Name: Robert Ellerhorst
Commenter Affiliation: Michigan State University
Document Control Number: EPA-HQ-OAR-2002-0058-3674-A2
Comment Excerpt Number: 4

Comment: The emissions data for CO from each of the best performing units was obtained from 3 consecutive 1-hour stack tests, which are typically performed at maximum or normal operating loads and do not account for startups and shutdowns. U.S. EPA obtained actual CO CEMS data from two coal-fired units and noted that CO emissions from these units did not vary at loads below the design capacity. As such, the proposed CO emission limit encompasses all operating loads and does not include periods of startup and shutdown.

Response: The EPA acknowledges this comment.

Commenter Name: Michael D. Wendorf
Commenter Affiliation: FMC Corporation
Document Control Number: EPA-HQ-OAR-2002-0058-3453-A1
Comment Excerpt Number: 7

Comment: EPA's proposed reduction of the CO limits for existing pulverized coal boilers is of particular concern. The CO limit in the final rule when using stack testing is 160 ppm; the proposed limit drops to 41 ppm, both corrected to 3% oxygen. Our existing PC boilers have been configured to minimize NO_x formation in the furnace for compliance with Section 308 of the CAAA Regional Haze Rule for prevention of visibility impairment in Class I areas. The proposed CO limit will require excess oxygen levels in the furnace to be increased significantly which will create a fuel-lean condition; this will be detrimental to the effectiveness of the existing controls that inhibit NO_x formation.

Response: For the reasons listed in the preamble to the March, 2011 final rule, EPA believes that oxidation catalysts may be used to reduce CO emissions without increasing emissions of

NOx. The installation and operation of an oxidation catalyst would allow sources to reduce their CO emissions without significantly impacting boiler operating parameters (such as excess air) because the catalyst treats the effluent gas from the boiler instead of being placed in the combustion chamber. Control costs for oxidation catalysts were factored into EPA's cost analysis. Further, EPA has implemented minimum CO emission limits of 130 ppm for all subcategories for which the calculated 99% UPL is less than 130 ppm. EPA believes the less stringent limit and the applicability of oxidation catalysts mitigate the commenter's concerns about significantly altering existing operating conditions.

Commenter Name: Michael D. Wendorf

Commenter Affiliation: FMC Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3453-A1

Comment Excerpt Number: 8

Comment: Compliance with the proposed CO limit will require substantial modifications to the fuel-air management systems on our boilers and may ultimately require add-on emission control equipment to capture the NO, generated from the fuel-lean combustion requirements. As a practical matter, it seems contrary to good regulatory management by proposing a CO limit which promotes formation of NOx, a long-established NSPS criteria pollutant and regulated as a precursor pollutant for visibility and deposition impairment in Class I areas.

Response: For response to CO limits for existing pulverized coal boilers necessitating increased excess oxygen and creating fuel-lean scenarios, see comment EPA-HQ-OAR-2002-0058-3453-A1, excerpt 7.

3F06. MACT Floor Results: Existing Biomass – Fluidized Bed

Commenter Name: Gretchen Brewer

Commenter Affiliation: PT AirWatchers

Document Control Number: EPA-HQ-OAR-2002-0058-3825-A1

Comment Excerpt Number: 2

Comment: For fluidized bed, biomass fuel cells, and biomass hybrid suspension grate, the limits for existing units should be adjusted down to the same level as for new units.

Response: EPA disagrees that existing source emission limits should be adjusted downward to be identical to the new source emission limitation for the same subcategory. The commenter provides no rationale for such an approach.

Commenter Name: Gretchen Brewer

Commenter Affiliation: PT AirWatchers

Document Control Number: EPA-HQ-OAR-2002-0058-3825-A1

Comment Excerpt Number: 1

Comment: The gap between existing unit and new unit standards for the following three control technologies are excessive, especially as compared with the difference for other technologies listed.

- Fluidized bed - existing @ 0.11 lb/MMBtu ; new @ 0.0098 lb/MMBtu
- Biomass Fuel cells - existing @ 0.033 ; new @ 0.011 lb/MMBtu
- Biomass Hybrid suspension grate - existing @ 0.44 ; new @ 0.026 lb/MMBtu

Response: The MACT floor emission limits for these subcategories have been recalculated. Due to the reclassification of units in the major source boiler and process heater inventory, the Biomass Fuel Cell emission limitation for filterable PM for existing sources is now less stringent than the limit in the December, 2011 proposed reconsideration of the rule. The Fluidized Bed and Hybrid Suspension/Grate filterable PM emission limits remained unchanged. The existing source limits for these units are calculated based on the variability of the emissions data from the top 12% of the emitters in the subcategory, as per the requirements of the Clean Air Act. Further, the CAA requires that new source MACT floor limits be based on the emissions performance of the best performing similar source, and that existing source floor limits be based on the average emissions performance of the best performing 12 percent of sources in the subcategory, and EPA has calculated floor limits according to the requirements of the Act. Moreover, EPA does not believe the gap between the existing and new source limits are excessive. For response to the request that emission limits for existing Fluidized Bed units, biomass Fuel Cells, and biomass Hybrid Suspension/Grate units should be adjusted downward to be at the same level as the new source emission limits, please see comment EPA-HQ-OAR-2002-0058-3825-A1, excerpt 2.

3F08. MACT Floor Results: Existing Biomass – Suspension Burner

Commenter Name: Mark Weiss

Commenter Affiliation: Reciprocal Energy Company

Document Control Number: EPA-HQ-OAR-2002-0058-3658-A2

Comment Excerpt Number: 2

Comment: We believe that the data used to set parameters for CO emissions within the Major Source Rule raises questions about the methodology for data acquisition and its application in the Rule. I am referring specifically to the data points and resulting limits for both the 3-hour and ten day test for CO.

The standard for CO is posted as: Existing—Biomass Suspension Burner.... 58 PPM or CEMS 1,400 PPM. It is unclear if they were recorded with fossil fuel supported flames. 58 PPM of CO is not achievable in most, if not all, suspension combustion applications using field-processed biomass. A typical suspension combustion power plant in Europe will operate at or below 200-300 PPM of CO. Low firing rates will typically produce higher CO readings.

Response: EPA has recalculated the CO MACT floor emission limitation for this subcategory. The resultant limit is less stringent than the limit in the December, 2011 proposed reconsideration of the rule. EPA believes that all suspension combustion applications should be able to demonstrate compliance with the final rule limitation since all top performer 3-run test averages are demonstrating compliance with the revised limit (see the memo titled "MACT Floor

Analysis for the Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP" in the docket).

Commenter Name: Mark Weiss

Commenter Affiliation: Reciprocal Energy Company

Document Control Number: EPA-HQ-OAR-2002-0058-3658-A2

Comment Excerpt Number: 5

Comment: The required testing is designed for long, steady full fire. Many applications do not allow for steady state full fire. These "load following" applications minimize fuel consumption/emissions but the testing protocols are not applicable to these installations, by type.

Response: The CO MACT floor emission limitation for Suspension Burners designed to combust biomass or bio-based solid fuel was calculated from the emissions of a load-following boiler. Moreover, some of the load-following units are currently meeting the CO limit (see the memo titled "MACT Floor Analysis for the Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP" in the docket). EPA therefore disagrees that load-following units will have difficulty demonstrating compliance with the testing requirements and emission limitations in the rule.

Commenter Name: Mark Weiss

Commenter Affiliation: Reciprocal Energy Company

Document Control Number: EPA-HQ-OAR-2002-0058-3658-A2

Comment Excerpt Number: 7

Comment: Size matters. Small boilers (under 100,000 pounds of steam per hour) used primarily for thermal can have higher CO levels given turn down requirements. These applications can play a vital role in reducing dependency on fossil fuels and over-all emissions.

Response: The CO MACT floor emission limit for Suspension Burners designed to combust biomass or bio-based solid fuels is calculated from the emissions of a boiler rated at less than 100,000 pounds of steam per hour. EPA acknowledges the comment that small boilers play a vital role in reducing the dependency on fossil fuels and overall emissions.

Commenter Name: M.L. Steele

Commenter Affiliation: CraftMaster Manufacturing, Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3814-A1

Comment Excerpt Number: 9

Comment: CO MACT Limit for Suspension Burner biomass subcategory. The proposed limit of 58 ppm_{dvc} is unrealistic and must be questioned. We base this statement on the following points:

a) The limit does not remotely compare to any of the other biomass subcategories. The next lower limit is four times higher.

b) The limit is based on test data from only one source.

- c) CraftMaster's experience with a combination suspension-fired and stoker-fired biomass unit is that CO is higher when firing in suspension yet the CO limit for stokers is 13 times higher than the proposed suspension limit.
- d) The CO MACT limit for Suspension burners is not consistent with the CO GEMs MACT limit for the same subcategory. While the CO MACT limit is the lowest, the CO GEMs MACT limit of 1400 ppm_{dvc} is the highest of all the biomass subcategories.
- e) Was the biomass fuel fired during the stack test process-specific or representative of that used by the entire subcategory?
- f) Was any co-firing of other fuels occurring during the stack test?
- g) Is the relatively small size (40 MMBtu per hour) of the unit tested representative of the entire subcategory?
- h) What were the combustion conditions (%excess air, etc.) during the CO stack test and are they transferrable to the entire subcategory?

Response: EPA has revised the CO MACT floor emission limitation for Suspension Burners designed to combust biomass or bio-based solids since the December, 2011 proposed reconsideration of the rule. The revised emission limit is less stringent than in the proposed rule. The revised CO CEMS MACT emission limit is also less stringent than was proposed.

Given the limited amount of available emissions data from units in this subcategory, the emission limit is still calculated from the emissions from a single unit. This is consistent with the language of section 112(d)(2), which requires that MACT floor limits be calculated based on the best performing twelve percent of units "for which the Administrator has emissions information[.]" not the best performing twelve percent of units in the entire subcategory. In some cases, as in this case, where EPA lacks emissions information for all units in the subcategory, the floor limit must therefore be established based on fewer than the top twelve percent of all such units. The top performing unit reported four separate 3-run emissions tests, each of which is combusting at least 90 percent plywood generated on-site. One of the tests co-fires natural gas, which accounts for approximately 5 percent of the heat input during the test. However, the best-performing test reported by the facility combusts 100 percent plywood.

The average design capacity for all major source boilers and process heaters in the Suspension Burner subcategory is 56 MMBtu per hour and the median design capacity for the subcategory is 40 MMBtu per hour. For this reason, EPA believes that the size of the top performer (40 MMBtu per hour) is an accurate representation of the entire subcategory. Finally, EPA believes that the commenter's concerns regarding differences in the combustion conditions of the top performer test data are addressed by the CO limit in today's final action, which is less stringent than the proposed limit.

Commenter Name: M.L. Steele

Commenter Affiliation: CraftMaster Manufacturing, Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3814-A1

Comment Excerpt Number: 7

Comment: CO MACT Floors and Limits for biomass subcategories

The CO MACT limits for the "Suspension Burners" and "Dry Stokers" subcategories are based on only one stack test in each subcategory. This limited sample size simply cannot be indicative of the emissions being achieved by the average of the best performing 12% of units in the source category. Per USEPA's data these subcategories contain 47 (Suspension) and 74 (Dry Stokers) units. Then the number of units in the top 12% would be 6 and 9 for the Suspension Burners and Dry Stokers subcategories, respectively. Test data is available to USEPA for 6 units in each subcategory but USEPA considers only one test on one unit in each subcategory to establish the MACT limits. Ironically, if the source categories had contained fewer units (< 30) USEPA would be required to include test data from a greater number (5) of units in the MACT Floor average.

We believe USEPA is pre-mature in issuing any firm limit for an entire source category based on test data from a single unit.

Response: For a general response to issues with the Suspension Burner CO emission limitation being calculated from the emissions data from a single unit, please see comment EPA-HQ-OAR-2002-0058-3814-A1, excerpt 9. Consistent with other rulemakings, the top 12 percent of units in a subcategory applies to the number of units with available test data and not the total number of units in the subcategory. In subcategories for which EPA has emissions information for only 6 units, a single unit represents the top 12 percent when rounding up to the nearest whole number.

3F09. MACT Floor Results: Existing Biomass – Hybrid Suspension/Grate

Commenter Name: Responsible Citizens

Commenter Affiliation: John Smith

Document Control Number: EPA-HQ-OAR-2002-0058-3531-A1

Comment Excerpt Number: 2

Comment: In the December 2011 proposed rule, EPA introduced a new biomass boiler subcategory (the hybrid suspension/grate boiler). The PM limits on this new subcategory are more than 10 times more lenient than the limits on other biomass boilers. The CO limit (3900 ppm) is 100 times more lenient than other biomass units. Even though EPA describes this new subcategory as being developed for the small number of bagasse-fired boilers, the definition of the subcategory makes it very easy for a large majority of biomass boilers that fire non-dry fuel to be categorized in the hybrid suspension/grate subcategory. EPA MUST place more restrictions on the boilers that fall under this category. Otherwise the result will be a majority of grate-based biomass boilers being categorized under this dubious subcategory. Many of these existing units are already subject to NSPS standards for PM (0.10 lb/MMBtu), so it is inexplicable that EPA would roll out a PM MACT standard four times greater than the NSPS. And that the CO standard would be 100 times greater than the levels many of these units already operate at.

Response: EPA has revised the CO MACT floor emission limitation for Hybrid Suspension/Grate units designed to combust biomass or bio-based solid fuels. The revised emission limit is more stringent than the limit in the December, 2011 proposed reconsideration of the rule. EPA has revised the definition of the Hybrid Suspension/Grate subcategory such that

only the intended Hybrid Suspension/Grate biomass combustors meet the definition of the subcategory.

3F10. MACT Floor Results: Existing Wet Biomass – Stoker/Sloped Grate/Other

Commenter Name: John S Williams

Commenter Affiliation: Maine Pulp & Paper Association (MPPA)

Document Control Number: EPA-HQ-OAR-2002-0058-3466-A1

Comment Excerpt Number: 6

Comment: CO Standards are problematic.

The new CO limits are particularly problematic for stoker boilers burning wet biomass¹ (such as those at the S.D. Warren Somerset, Lincoln Paper & Tissue, Verso Paper and Old Town Fuel & Fiber mills). Boiler adjustments and costly combustion air reconfigurations (which are not even physically possible on some older boilers) are not likely to be sufficient for some biomass stoker boilers to meet the CO limits. Further, CO catalysts which convert CO to CO₂ (a greenhouse gas) and which typically cost over one million dollars may get poisoned, making them ineffective.

The Boiler MACT CO limits would necessitate combinations of emission controls that would have adverse effects on each other, and even then are unachievable for certain biomass boilers at Maine mills.

Response: EPA has revised the CO MACT floor emission limitation for Stokers/Sloped Grate/Other units designed to combust wet biomass fuel. The revised emission limitation is less stringent than the limit in the December, 2011 proposed rule, and EPA believes that the commenter's concerns regarding the potential impacts of different control technologies on each other are addressed by the revised limit. Approximately 78 percent of the units in this subcategory with CO emissions data reported at least one test that is demonstrating compliance with the revised CO emission limit.

3F11. MACT Floor Results: Existing Dry Biomass – Stoker/Sloped Grate/Other

Commenter Name: Bill Lane

Commenter Affiliation: American Home Furnishings Alliance (AHFA)

Document Control Number: EPA-HQ-OAR-2002-0058-3676-A2

Comment Excerpt Number: 2

Comment: We have some concerns about the specific criteria and requirements for the dry biomass subcategory. Most importantly, we are very concerned that the emission standard for carbon monoxide (CO) from existing boilers (250 ppm corrected to 3% oxygen) is not representative of the best performing boilers that belong in the subcategory. According to the EPA database, the MACT floor determination that produced this limit is based on the emissions data from the Algoma hardwood facility located in Algoma, Wisconsin. It is our understanding that this facility is a synthetic minor facility. AHFA believes that the facility should not be

considered in the MACT floor analysis because as a HAP minor source it is not part of the kiln-dried biomass subcategory for the major source Boiler MACT.

Response: EPA agrees that the Algoma Hardwood facility located in Algoma, Wisconsin is a synthetic minor source of HAP emissions, and has been reclassified as such in the EPA ICR Databases. As such, the emissions data from this source have been excluded from the calculation of MACT floor emission limits.

Commenter Name: Bill Lane

Commenter Affiliation: American Home Furnishings Alliance (AHFA)

Document Control Number: EPA-HQ-OAR-2002-0058-3676-A2

Comment Excerpt Number: 3

Comment: We are aware that very little CO emission data were available for calculation of the MACT floor in the kiln-dried biomass boiler subcategory. The lack of data for CO and other target pollutants strongly suggests that additional time for source evaluation is warranted prior to finalizing the MACT floor for this subcategory. Although insufficient time was available for a thorough evaluation of existing sources, the AHFA initiated an ongoing CO test program with the objective of identifying the magnitude and range of previously unknown CO emissions in the kiln-dried biomass subcategory. Preliminary results demonstrate sizeable variability within the subcategory, with CO measurements @3% oxygen ranging from 211 ppm to nearly 35,000 ppm. We are concerned that this high level of variability in such a small subcategory is not adequately accounted for in the current floor calculation method employed by EPA.

Response: EPA is required to establish MACT floor levels based on emissions limits achieved by sources for which emissions information is available to the Administrator. The MACT floor emission limitations were calculated from available emissions data in the EPA ICR Databases. EPA acknowledges that CO emissions can fluctuate greatly from units combusting biomass or bio-based solid fuels. The commenter did not provide enough information relative to the CO emissions data from kiln-dried biomass combustion ranging from 211 to 35,000 ppm to allow the data to be incorporated into the EPA ICR Databases.

3F12. MACT Floor Results: Existing Liquid

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 45

Comment: We have heard from numerous vendors that they cannot guarantee many of the liquid and gas CO limits. Low-NOX burner (LNB) designs for gas-fired boiler applications manipulate the stoichiometry within the flame to minimize NOX formation. These designs establish a fuel-rich zone for the initial phase of combustion, and then add air at a later stage in the outer regions of the flame. In the initial phase, there is not sufficient oxygen available to form significant amounts of NOX, and in the secondary phase, the flame is much cooler, which also inhibits NOX formation. However, these burners often operate with CO emission up to 10 ppmvd in the upper part of the load range. At mid loads, the CO begins to increase near 50

ppmvd, and at low loads, it may exceed 100 ppmvd. Older or "first generation" low NOX burners are reported to generate even higher levels of CO for a given NOX reduction. These low-NOX burners will not be able to achieve CO emissions as low as the 4 ppmvd levels proposed by EPA, and many older existing units will not be able to achieve a CO limit below 100 ppmv. As EPA is on the verge of establishing a lower ozone standard, many more facilities will likely be installing low-NOX burners. Further, specifying CO limits below those needed to achieve good combustion and organic HAP destruction levels is expected to result in facilities having to replace many existing LNB currently in service.

Response: EPA investigated the relationship between CO and NOx for the top performer emission tests by calculating a NOx-to-CO ratio for all tests where NOx data were available. High ratios suggest that low levels of CO are achieved at the expense of elevated NOx emissions. For existing source floor calculations, EPA believes that the variability in emissions of all top performers accounts for the cases where CO emissions are minimized by increasing NOx emissions. Several of the top performing CO emitters have low NOx burners installed and exhibit both low CO and low NOx emissions. EPA acknowledges that emissions of CO and NOx can affect one another, but believes that the presence of units with low NOx burners exhibiting low CO and low NOx emissions, as well as the resultant variability of the units comprising the top 12 percent, mitigates any concerns that liquid-fired combustion units with low NOx burners will be unable to demonstrate compliance with the CO emission limitations for liquid-fired units in the rule.

Commenter Name: Mary Sullivan Douglas

Commenter Affiliation: National Association of Clean Air Agencies (NACAA)

Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1

Comment Excerpt Number: 25

Comment: EPA's proposed limits for Hg emissions from liquid-fired boilers reveal the magnitude of EPA's decisions respecting (1) the level of precision to be employed in conducting emission testing and fuel analysis, (2) determining variability of "best" sources with insufficient data, (3) "pooling" variance among different sources where there is no reason to believe that each of those sources has the same amount of variability, and (4) determining the UPL based on emission data where the source is not "in compliance."

Distillate oil (#2 oil) is commonly understood to contain far less Hg than coal or biomass; while residual oil (#6 oil) contains somewhat less Hg than solid fuels. EPA's existing source MACT floor is based on a series of test results from ten sources combusting four different types of oil.²³ Six sources submitted the results of a single compliance test and four sources submitted 41 fuel analyses. The arithmetic average of these results is 3.70×10^{-7} lb/MMBtu and the standard deviation is 3.07×10^{-7} lb/TBtu, suggesting that a reasonable MACT floor would be in the range of $1.0 - 1.5 \times 10^{-6}$ lb/MMBtu (a variability factor of 300 to 500 percent).²⁴ EPA's earlier UPL calculation led to the final rule MACT standard of 3.4×10^{-6} lb/MMBtu – a variability factor of over 900 percent. EPA's newly proposed statistical procedure results in a proposed UPL of 2.49×10^{-5} , using the same data. This number is more than 100 times the arithmetic average of the data and more than 100 times the standard deviation of the data set²⁵.

As a consequence, of the 71 sources for which EPA has data, only four sources will have to reduce emissions.

[Footnotes]

(23) MACT Floor Memo, Appendix C-4-(a)(i).

(24) A somewhat higher limit may be appropriate as many of the reported results were below detection limits, thereby constraining the variability that would have been demonstrated by more precise analyses. This effect is offset by the fact that the arithmetic average would be lower with more precise analyses, but the degree to which these factors offset is not known.

(25) Sources routinely maintain, and EPA agrees, that fuel variability is so small that sources only have to conduct new fuel analyses when they change suppliers.

Response: The mercury MACT floor emission limitation for liquid-fired units has been revised since the December, 2011 proposed reconsideration of the rule. The revised limit is more stringent than the proposed limit because of an error in the 99% UPL calculated for the proposed rule; mercury emissions from non-continental liquid boilers were inadvertently disregarded from the calculation of the 99% UPL at proposal, but were added to the calculation of the revised 99% UPL for the final rule. The more stringent limit requires more liquid-fired boilers to reduce mercury emissions than the proposed limit. As was done for the proposed rule, the mercury MACT floor emission limit for liquid-fired combustion units was computed from emissions data from both distillate and residual fuel oils.

EPA acknowledges that distillate oil and residual oil contain differing and varying levels of mercury content. However, the 99% UPL calculation was not changed for liquid-fired sources because the best performing sources contain emissions data from both distillate and residual oil (see the memo titled, "MACT Floor Analysis for the Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP" in the docket). Since the 99% UPL is calculated on data from both distillate and residual fuel oils, EPA believes the 99% UPL appropriately accounts for the variation in mercury content between the two fuels.

Commenter Name: Mary Sullivan Douglas

Commenter Affiliation: National Association of Clean Air Agencies (NACAA)

Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1

Comment Excerpt Number: 26

Comment: As Table 1 demonstrates, many of the characteristics of the data for the liquid fuel-fired subcategory are similar to those in the solid fuel-fired subcategory and yet EPA's proposed

MACT floor for liquid fuel-fired boilers is nearly ten times higher than the proposed limit for solid fuel-fired units. [See submittal for Table 1] Charts 2 and 3 demonstrate the impact of EPA's determination of variability on the effectiveness of the rule. [See submittal or Charts 2 and 3] The average of the top 12 percent (lowest test value) in each case is well below 1.0×10^{-6} lb/MMBtu. If EPA had set the limit for coal-fired units at that level, approximately 25 percent of the subcategory would meet the limit and the balance would be required to take some steps to reduce emissions. At the proposed level of 3.1×10^{-6} lb/MMBtu, while the gross emitters would

have to take steps to comply, approximately two thirds of the units in the subcategory would not need to reduce emissions. For the oil-fired subcategory, only four of 71 units would have to reduce emissions at all; the proposed limit is five times higher than the emission rate of the fifth highest emitting unit in the subcategory.

These results do not appear to be consistent with EPA's obligation to set MACT floors at levels that represent the average of the performance of the top 12 percent.

NACAA attempted to discern why EPA's procedure generated such different results when the overall distribution of the Hg emissions data for coal and oil-fired units was so similar. The largest single reason for this vast difference appears to be a simple error in importing the data – EPA incorporates the emissions data for HCl instead of Hg into its UPL calculation.²⁶ With the correct data, EPA's 99th percentile UPL calculation yields a MACT floor of 4.58×10^{-7} lb/MMBtu.

[Footnote]

26 The error can be found in MACT Floor Memo, Appendix C, Worksheet "C-4(a)(iv)&C-4b(iv)" which is then carried over into Worksheet "C-4(a)(ii)."

Response: The mercury MACT floor emission limitation for liquid-fired units has been revised since the December, 2011 proposed reconsideration of the rule. The revised limit is more stringent than the limit in the proposed rule. The revised 99% UPL is still greater than 1.0×10^{-6} lb/MMBtu, but EPA believes that since the limit is more stringent than the limit in the proposed rule it correlates to a fair mixture of sources that will be required to reduce emissions and those which will not. For a response to the claim that only 4 units were required to reduce emissions to demonstrate compliance with the proposed limit, please see comment EPA-HQ-OAR-2002-0058-3525-A1, excerpt 25.

3F13. MACT Floor Results: Existing Heavy Liquid

Commenter Name: Dakota Gasification Company Great Plains Synfuels Plant

Commenter Affiliation: David W. Peightal

Document Control Number: EPA-HQ-OAR-2002-0058-3424

Comment Excerpt Number: 2

Comment: In previous comments, DGC requested that EPA evaluate DGC's stack test results and re-evaluate the variability of carbon monoxide emissions. DGC does not combust No. 6 fuel oil. DGC combusts byproduct fuels, residual type oils. This is similar to EPA's comment to the non-continental liquid units' discussion as far as type of combustion fuels. The stack test results from DGC demonstrated the variability in CO emissions. DGC's test run result for testing CO demonstrated that CO emissions at DGC's GPSP varied from 0.67 ppm to 187.11 ppm. These are one-minute values corrected to 3% Oz. In addition, EPA did not adequately address the inverse relationship with CO emissions versus NOx emissions management, which causes competing issues such as efficiency versus minimizing NOx emissions for permit compliance and may not leave a window to operate effectively. Operating parameters required to achieve 10 ppm CO emissions where EPA has not demonstrated that a 10 ppm CO limit is a true indicator of complete combustion of organic HAPs. DGC requests EPA to re-evaluate the proposed basis of

having a 10 ppm limit or an 18 ppm limit with an averaging time of 10 days for heavy liquid units that combust residual type fuels or other byproducts of heavy liquid fuels.

Response: The facility's emissions data have been incorporated into the EPA ICR Databases. EPA acknowledges that the units at the facility combust process-specific liquid fuels with similar characteristics to residual fuel oil. However, the heat input data reported for the emissions testing show that approximately half of the heat input from the test was obtained from these residual-type liquid fuels; the remaining heat input came from gaseous fuel. Thus, given the procedures outlined in the memo entitled, "Revised MACT Floor Analysis (May 2012) for the Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP" in the docket, the reported emissions data do not qualify for consideration in the calculation of the MACT floor emission limitations since the test data do not correlate with the combustion of at least 90% heavy liquid fuel.

For a response to the claim that EPA should evaluate the relationship between CO and NO_x emissions, please see comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 45 under the chapter for Existing Results: Liquid.

EPA disagrees that separate limits are justified for units combusting process-specific residual-type liquid fuels. Reported emissions from process-specific residual-type liquid fuels are comparable to emissions data from traditional residual fuel oil.

Commenter Name: Sarah E. Amick

Commenter Affiliation: Rubber Manufacturers Association (RMA)

Document Control Number: EPA-HQ-OAR-2002-0058-3503-A1

Comment Excerpt Number: 6

Comment: EPA is proposing a stringent set of emission limits for light and heavy liquid fuel boilers that are, in many cases, not based on the use of any technology. In many cases, light and heavy liquid fuel boilers are achieving low emission rates not due to use of any particular technology, but due to the mix of fuels being fired (which sometimes includes fuels with pollutant contents below the limits of detection) or other unit specific characteristics that are not transferable to other sources. Facilities are limited in the fuels that their boilers can fire by design, cost, permits, and fuel availability. EPA should not set limits for hundreds of liquid fuel boilers based on data from a few boilers in which the specific mechanisms resulting in lower emissions are not fully understood and that are not available to all units in the subcategory.

Response: The EPA disagrees that co-fired units are providing a downward bias to the MACT floor emission limitations for the Heavy and Light Liquid subcategories. The only pollutant for which the top 12 percent comprises a co-fired test is the CO MACT floor emission limitation for the Heavy Liquid subcategory. However, as seen in the memo titled "MACT Floor Analysis for the Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP" in the docket, there are several tests in this subcategory from units which reported they are combusting 100 percent residual oil and are demonstrating compliance with the CO emission limit in the rule.

3F15. MACT Floor Results: Existing Non-Continental Liquid

Commenter Name: Christopher Coleman

Commenter Affiliation: HOVENSA LLC. , Hess Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3673-A2

Comment Excerpt Number: 7

Comment: The API and AFPM comments both discuss the proposed limits for CO and PM. HOVENSA supports the view that the CO limit should be based on longer term data where that is available and that using a short 3 hour period is particularly inapt for oil fired units. This is primarily because of the need to switch fuels, but is also because of variability in the fuel gas system that is amplified in island refineries because of the absence of natural gas. See HOVENSA's comments on Proposed BPH MACT, pages 16 and 21-28. HOVENSA also supports the position taken by API and NFPM that a CO limit of 51 ppmv for a performance test is appropriate, based on the data available.

Response: EPA disagrees that longer than a 3-hour testing period should be required for non-continental units designed to combust liquid fuels. Several of the top performing CO and PM tests from these units were conducted during a 3-hour testing period, proving that a longer testing period is not necessary to determine compliance with the emission limitations in the rule. Further, EPA has implemented minimum CO emission limits for all subcategories for which the calculated 99% UPL is less than 130 ppm. For these reasons, EPA believes that the concern of non-continental liquids not being able to demonstrate with CO emission limits due to fuel variability is mitigated.

Commenter Name: Christopher Coleman

Commenter Affiliation: HOVENSA LLC. , Hess Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3673-A2

Comment Excerpt Number: 8

Comment: HOVENSA strongly supports the API and NFPM position on PM limits for non-continental units and the optional use of TSM. We concur that HOVENSA's units should be removed from the subcategory since they have been shut down, thus reducing the units in the category to below 30 sources. However, even if that were not so, using a single source to set the MACT floor makes no statistical sense and simply cannot be viewed as a fair view of the variability in operation between the tested Tesoro and Chevron units. This is underscored by the point that the Tesoro test was conducted at 40% load with a low PM but higher NOx emitting burner design. API and NFPM included manufacturer data that demonstrated that PM emissions are much lower at this load level. This data is confirmed by EPA's own compilation of emissions factors information for fuel oil combustion.

"Boiler load can also affect filterable particulate emissions in units firing No. 6 oil. At low load (50 percent of maximum rating) conditions, particulate emissions from utility boilers may be lowered by 30 to 40 percent and by as much as 60 percent from small industrial and commercial units."

Source: AP-42 Emissions Factors Chapter 1-3 Fuel oil Combustion, Section 1.3.3.1.

Accordingly, HOVENSA concurs that the API/AFPM .36 lbs/MMBTU is an appropriate emissions limit.

Response: For responses to the closure of the HOVESNA refinery in St. Croix and its effect on the non-continental liquid floors, as well as the desired PM emission limit of 0.36 lb/MMBtu for non-continental units, please see comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 63 under the chapter for Methodology: Non-Continental Liquid. For response to claim that low load operation causes higher PM emissions, please see comment EPA-HQ-OAR-2002-00583677-A2, excerpt 64 under the chapter for Methodology: Non-Continental Liquid.

Commenter Name: Lisa Barry

Commenter Affiliation: Chevron Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3687-A2

Comment Excerpt Number: 2

Comment: EPA's proposed PM limit for island oil-fired units of 0.008 lb/MMBtu is unrealistically close to the limit for gas-fired units. Since it is much easier to achieve low PM with gas than liquid, EPA's island limit is not logical or fair for heavy oil island boilers and heaters. We are concerned that the large cost could adversely affect the economic viability of our Hawaii refinery. The Clean Air Act requires different consideration when setting emission limits for subcategories with less than 30 units. With the island subcategory now under 30 units total (due to the cessation of refining operations by Hovensa in the Virgin Islands), EPA should comply with the Clean Air Act and re-calculate the emission limit based on the best five units, not the single lowest measurement that was taken at 40% load. Such low load greatly increases residence time, causing fuller combustion and lower PM, but it does not represent normal operation for other units. We note that the proposed PM limit for some biomass units is as high as 0.44 lb/MMBtu.

Response: EPA has revised the MACT floor emission limitations for all subcategories since the December, 2011 proposed reconsideration of the rule. The revised PM emission limit for non-continental units designed to combust liquid fuel is less stringent than the proposed limit, and is also less stringent than the PM limit for units designed to combust Gas 2 fuel. For a response to the closure of the HOVESNA refinery in St. Croix and its effect on the non-continental liquid floors, please see comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 63 under the chapter for Methodology: Non-Continental Liquid. For a response to the claim that low load operation causes higher PM emissions, please see comment EPA-HQ-OAR-2002-00583677-A2, excerpt 64 under the chapter for Methodology: Non-Continental Liquid.

Commenter Name: Lisa Barry

Commenter Affiliation: Chevron Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3687-A2

Comment Excerpt Number: 3

Comment: With the closure of the Hovensa refinery, the island subcategory now has less than 30 units total. Therefore, EPA should re-calculate the CO emission limit based on the best five units, not the single lowest unit. API/AFPM's comments today include a limit calculation using EPA's common method and the available island CO data that shows the island CO limit actually

should be approximately 210 ppm (3-hour, 3% O₂), which is much higher than EPA's proposed limit of 18 ppm. Also, the recent final NESHAP for electric generating oil-fired units has no CO limit, even though the units are similar to ours. We believe that EPA should strive to provide more equitable treatment across sectors.

Response: For response to the closure of the HOVESNA refinery in St. Croix and its effect on the non-continental liquid floors, please see comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 63 under the chapter for Methodology: Non-Continental Liquid. The revised CO emission limits using the new dataset are shown in the final rule. EPA disagrees with removing CO emission limits in order to maintain consistency with 40 CFR Part 63 Subpart UUUUU. While the units are similar to electric generating units, they are not identical. Further, CO is regulated as a surrogate for organic HAP, which poses a significant threat to the environment and human health. With many more sources subject to this rule compared to Subpart UUUUU, organic HAP emissions cannot be ignored.

Commenter Name: Douglas Price

Commenter Affiliation: Tesoro Companies, Inc

Document Control Number: EPA-HQ-OAR-2002-0058-3630-A2

Comment Excerpt Number: 1

Comment: *Non- Continental Liquid Subcategory Emission Limits*

Although the re-proposed 40 C.F.R. 63 Subpart DDDDD has improved certain compliance options and emission limits, there remains a great deal of uncertainty whether it will be feasible for the Kapolei Refinery to meet the re-proposed "non-continental liquid subcategory" standards on a consistent basis. This is because those re-proposed standards were developed based on source test data from very few {2 -3} of the sources within the "non-continental liquid subcategory." In addition, some of the sources were tested during a specific operating regime. The uncertainty regarding the ability to routinely meet the re-proposed emission limits, and the potential costs of changing operations or adding controls in order to meet the re-proposed limits, is a large concern for Tesoro. The API/AFPM comment letter provides recommendations, consistent with methods used by EPA, for addressing the limited source test data and potential for variability when setting the emission limits for the non-continental liquid subcategory. The API/AFPM comment letter also provides suggested revised limits for the non-continental liquid subcategory.

Response: For a response to the claim that using data from few sources to set an emission limit for the Non-Continental Liquid subcategory is not appropriate, as well as a response to the claim that specific operating regimes have an effect on emissions, please see comment EPA-HQ-OAR-2002-0058-3673-A2, excerpt 63. EPA has recalculated the MACT floor emission limitations for all subcategories since the December, 2011 proposed rule. For non-continental units designed to combust liquid fuels, the emission limits for CO and PM are less stringent than those in the proposed rule, which should address the commenter's concerns about the achievability of the proposed limits.

3F16. MACT Floor Results: Existing Gas 2 (Other Process Gases)

Commenter Name: Russell A. Wozniak

Commenter Affiliation: The Dow Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3449-A1

Comment Excerpt Number: 8

Comment: Dow requests that the CO emission limit for Units designed to burn gas 2 (other) gases of 4 ppmv, dry corrected to 3% O₂, be revised to at least 20 ppmvd at 3% O₂ in order to accommodate limitations in the analytical methodology as well as to not make the CO emission requirement contradictory to other emission requirements.

The current proposed CO level (4 ppmv @ 3% Oxygen) for Units designed to burn gas 2 (other) gases is at a level that challenges the repeatability of the required method (Method 10). A paper submitted to EPA by the National Council for Air and Stream Improvement (NCASI) 1 makes several references to Method 10 regarding the ability to provide quantifiable CO data at levels below 10 ppmv. This observation puts into question the datasets used to develop the operating limit due to CEMs being calibrated against Method 10 as well as the determination that 4 ppmv is a quantifiable value in determining compliance. An additional challenge is the requirement to correct measured CO values to 3% oxygen while maintaining a minimum demonstrated oxygen level. Operating at higher excess air levels (oxygen levels) is a typical means to reduce CO levels. Typically the facility, during a demonstration test required by the rule may set a 4% oxygen level during the test that then becomes an operating limit. During normal operations the facility may operate at 7% O₂ in order to avoid drifting below the 4% compliance limit. Incorporating the oxygen correction factor required by the rule would make the 4 ppmv corrected equivalent to a 3 ppmv measured. The result is a 25% reduction in the measured value, further challenging the analytical method.

[Footnote]

1. National Council For Air and Stream Improvement, Inc. Southern Regional Center Letter of July 15, 2011, addressed to Mr. Brain Shrager, Energy Strategies Group (C205-01), Sectors Policies and Program Division, US Environmental Protection Agency, Research Triangle Park, NC 27711.

Response: EPA disagrees that emissions below 20 ppm measured following the procedures of Method 10 are unrepeatable or inaccurate. Several facilities reported Method 10 tests to the EPA ICR Databases for which CO emissions are below 20 ppm. Several individual units reported multiple CO tests under the 20 ppm threshold. However, EPA has implemented minimum CO emission limits of 130 ppm for all subcategories for which the calculated 99% UPL was less than 130 ppm. EPA believes these minimum CO emission limits mitigate the concerns identified in the NCASI letter to EPA dated July, 2011.

Commenter Name: Russell A. Wozniak

Commenter Affiliation: The Dow Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3449-A1

Comment Excerpt Number: 10

Comment: The proposed CO level raises the question of the performance requirement demanded by the specification. Under the HWC MACT rule, a destruction efficiency of 99.99% is required. Allowing for a generic VOC as a feed, the 4 ppmv CO requirement calculates to a greater than 99.997% destruction efficiency. Using the same oxygen correction factors (3%), a 99.99% destruction efficiency is equivalent to a CO concentration of 16 to 18 ppmv.

Response: EPA has imposed a minimum CO emission limit of 130 ppm for all subcategories for which the calculated 99% UPL was lower than this level. EPA believes the minimum CO emission limit mitigates the commenter's concerns since the minimum CO emission limit of 130 ppm corresponds to a destruction efficiency of much lower than 99.997%.

3G01. MACT Floor Results: New Solid

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 67

Comment: Of the 26 facilities in our database that list HCl emission rates, rates range from 0.00083 to 0.02 lb/mmbtu. There are 36 facilities in the database that list some kind of acid gas control, such as trona injection, trona plus wet scrubber, pulverized limestone injection, dry scrubber, etc. Not all of these specify an actual emission rate however. Many permits that are synthetic area sources for HAPs simply specify that HCl emissions are capped at less than 10 tons per year, and they basically promise that they will keep adding sorbent until they reduce the emission rate to an acceptable level.

For facilities that do list rates, the red dots in the graph designate rates at facilities that will use of some kind of acid control. [See submittal for graph.]

Response: The EPA acknowledges this comment.

Commenter Name: Pat Dennis

Commenter Affiliation: Archer Daniels Midland Company

Document Control Number: EPA-HQ-OAR-2002-0058-3670-A2

Comment Excerpt Number: 4

Comment: The HCl limit for new solid fuel boilers will likely not be achievable for coal fired boilers without resorting to exorbitant control measures. The HCl solid fuel floors appear to be dominated by biomass combusting boilers. EPA should not group biomass boilers with coal boilers for HCl due to the general lack of chloride content of biomass and the widely varying chloride content found in coal. The lack of chloride in biomass indicates nothing about the ability to control HCl in a coal fired boiler. The HCl limit for existing boilers will likely not be achievable for fluidized bed boilers burning coal with any significant chloride content.

Response: In the final rule, the HCl MACT floor emission limits for both existing and newly constructed solid fuel boilers and process heaters are equivalent. Approximately 44 percent of the solid fuel HCl emitters in the EPA ICR Databases reported at least one test that is in

compliance with the limit in the final rule. Many of these tests are combusting coal or other solid fossil fuels. EPA acknowledges that some biomass fuels have lower emissions of regulated HAP than other solid fuels, but disagrees that the HCl limits are unachievable for new coal-fired boilers since many existing coal-fired boilers are already demonstrating compliance with the limit (as shown in the memo titled "MACT Floor Analysis for the Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP" in the docket). EPA believes that the 99% UPL accounts for the variability of chloride content of coal and biomass fuels.

3G03. MACT Floor Results: New Coal – Fluidized Bed

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 29

Comment: In the Reconsidered Boiler MACT Rule, EPA proposes to retain the final standard of 0.0011 lb/MMBtu, but to split the units into subcategories. As CIBO indicated in its Petition for Reconsideration of the Final Boiler MACT Rule, the PM limits finalized for new solid fuel-fired boilers are unachievable. Newer coal-fired units do not come close to meeting the standards.

CIBO believes that the limits are skewed based on data from one of the units relied on to set floor, which is not representative of units in the category. The boiler that set the solid fuel floor for PM, designated as IA Archers Daniels Midland Des Moines is a small bubbling bed boiler burning low ash coal and equipped with an oversized baghouse. The baghouse is designed for greater than nameplate boiler capacity whereas the boiler typically operates at less than nameplate capacity. As such, its extremely conservative design is not representative of the community of solid fuel boilers. The data from that boiler should not be relied on, as it is outlier data from a unit equipped with controls that are not considered standard for the unit.

Response: EPA has revised the PM MACT floor emission limitations for all subcategories since the December, 2011 proposed reconsideration of the rule. The revised PM limit for new Fluidized Bed units designed to combust coal or other solid fossil fuels is less stringent than the limit in the proposed rule due to corrections made to the reported emissions for the best performing source.

EPA disagrees that the top performer should be disregarded from the new source PM MACT floor emission limit for this subcategory. EPA agrees that the oversized baghouse is a conservative design from an emissions standpoint, but other sources are not prevented from installing a similar oversized control. An oversized baghouse only provides a greater PM removal, and does not correlate to any technical reason for the emissions data to be invalidated. Further, given that section 112(d) was intended as a technology-forcing provision that would result in application of the best emission reduction technologies, it would be inconsistent with the purpose of section 112 to ignore a source simply because it is using a technology that reduces emissions beyond what other sources are achieving. This is particularly true for new sources, where Congress required the MACT floor to be no less stringent than the best performing similar

source, since new sources should be able to design and construct units taking into account the application of control technologies needed to meet emissions standards.

Commenter Name: Pat Dennis

Commenter Affiliation: Archer Daniels Midland Company

Document Control Number: EPA-HQ-OAR-2002-0058-3670-A2

Comment Excerpt Number: 2

Comment: In the Reconsidered Boiler MACT Rule, EPA proposes to retain the final new source PM standard of 0.0011 lb/ MMBtu for fluidized bed boilers. This limit is not achievable for new fluidized bed boilers. ADM believes that the limit is skewed based on data from one of its own units relied on to set the floor, which is not representative of units in the category. The boiler that set the solid fuel floor for PM, designated as IAArchersDanielsMidlandDesMoines is a small bubbling bed boiler burning low ash coal and equipped with an oversize baghouse. The baghouse is designed for greater than pennitted heat input capacity. As such, its extremely conservative design is not representative of the community of solid fuel boilers. The data from that boiler should not be relied on, as it is outlier data from a unit equipped with controls that are not considered standard for the unit. ADM has started up five large CFB boilers since 2008. The filterable PM emissions from these boilers approximated 0.0040 lbs/mmbtu from the initial compliance demonstrations. Based on this experience, a limit of 0.010 lbs/mmbtu would be much more achievable for new well-controlled fluidized bed boilers.

Response: For response, see DCN EPA-HQ-OAR-2002-0058-3534-A1, Excerpt No. 29.

Commenter Name: Pat Dennis

Commenter Affiliation: Archer Daniels Midland Company

Document Control Number: EPA-HQ-OAR-2002-0058-3670-A2

Comment Excerpt Number: 3

Comment: The ADM unit referenced above, IAArchersDanielsmidlandDesMoines, would not meet the proposed TSM limit for new or existing boilers. Also, ironically, the fluidized bed unit that set the floor for the TSM limit, ILPolyOne, would not meet the new source fluidized bed limit for filterable PM. This is not a logical outcome and EPA should ensure that the MACT limits are achievable by the best controlled sources. In the case of the new source filterable PM for fluidized bed boilers and the TSM limits, they are not.

Response: In the final rule, EPA has established a single PM emission limitation (and TSM alternative) for all units designed to combust coal or other solid fossil fuels. The resultant TSM alternative limit is less stringent than the limit for new Fluidized Bed units designed to combust coal or other solid fossil fuels in the December, 2011 proposed reconsideration of the rule.

Reported emissions data from ILPolyOne to the EPA ICR Databases show that the Fluidized Bed unit at the facility is demonstrating compliance with the revised new source TSM alternative limit in the final rule as well as both the revised existing source PM and TSM limits in the final rule. Reported emissions data from IAArchersDanielsMidlandDesMoines show that the Fluidized Bed unit at the facility is demonstrating compliance with both the new and existing source revised PM emission limits in the final rule. Since compliance with TSM limits can be

demonstrated as an alternative to compliance with the PM limits, EPA believes the less stringent emission limits in the final rule mitigate the commenter's concerns about the achievability of the limits.

3G05. MACT Floor Results: New Biomass – Dutch Oven/Pile Burner

Commenter Name: Mary Sullivan Douglas

Commenter Affiliation: National Association of Clean Air Agencies (NACAA)

Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1

Comment Excerpt Number: 38

Comment: EPA's proposed standards are also highly sensitive to the decisions to exclude clean sources without sufficient basis and to retain highly variable results that are more properly treated as outliers. This is especially true in EPA's new source MACT floor calculations. By way of example, for one new source subcategory³⁸, the source had been tested twice, for a total of six runs. Results from five of the six runs were low and consistent; but the results of the sixth run were 100 times greater than any of the other five runs. Since this result is outside the 99th percent confidence level of the rest of the data set, under EPA's methodology it should have been excluded. EPA retained this value and the result is an extremely high new source MACT floor calculation.

[Footnote]

38 Biomass Dutch Oven Filterable PM.

Response: EPA has revised the PM emission limitation for Dutch Ovens/Pile Burners combusting biomass or bio-based solid fuels since the December, 2011 proposed reconsideration of the rule. The revised PM emission limit for this subcategory is more stringent than the proposed limit. EPA disagrees that the single run for the previous top performer should be disregarded because the test reports for both emissions tests were reviewed and no issues were found with the testing methodology. However, additional emissions data provided during the public comment period have resulted in a different combustion unit being the top performer for this subcategory. The average emissions for the new top performer are seven times lower than the previous top performer, and there is significantly less variability in the emission values across all test runs, resulting in a more stringent 99% UPL. For further detail on the calculation of the MACT floor emission limit for this subcategory, please see the memo titled, "MACT Floor Analysis for the Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP" in the docket.

3G10. MACT Floor Results: New Wet Biomass – Stoker/Sloped Grate/Other

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 65

Comment: All new and re-permitted facilities in our database use either a baghouse or ESP for PM control. These technologies are assumed capable of removing >99% of PM; baghouse removal rates of 99.9% and above are sometimes promised in air permits.

Not every permit specifies a separate emission rate for filterable PM versus total PM. For those in the database that do (there are 19 of them), values range from 0.0075 to 0.03 lb/mmbtu. In the graph [see submittal for graph], red dots designate bubbling fluidized bed boilers or circulating fluidized bed boilers; blue dots designate stokers. Given the similarity of the emission rates, it is not clear why EPA has designated such a large difference in the between the new unit standard for "wet" stokers (0.029 lb/mmbtu) and BFB's (0.0098 lb/mmbtu). These units appear to be using the same technologies and achieving the same emissions rates for PM.

Response: MACT floor emission limits for new sources were calculated from the emissions performance of the best-performing similar source as reported in the EPA ICR Databases. No enforceable permit limit constraints were considered in the calculation of these emission limits because permit limits which have not been verified through performance testing are not sufficiently reliable to use as a basis for identifying best performing units. This is supported by the commenter's own statements "are sometimes promised in air permits" and "appear to be achieving." Further, the commenter did not submit their database, so we are unable to determine if any of these permitted units have actually been constructed or whether they may already be in EPA database. While EPA acknowledges that Stokers and Fluidized Bed units combusting biomass fuel may be using similar controls, the emission limitations reflect the variability of actual emissions data reported to EPA. Pursuant to section 112(d)(3), the MACT floor must be based on the best performing sources for which the Administrator has emissions information. However, EPA has also analyzed the appropriateness of going beyond the floor for the new source PM emission limits and it has determined that in several instances it is cost effective to go beyond the floor to the level of the boiler NSPS (0.03 lb/mmBtu) for new sources in cases where the MACT floor emission limit is less stringent than this value. Refer to the preamble and the memorandum "Beyond the Floor Technology Analysis for Major Source Boilers and Process Heaters (Revised August 2012)" for a discussion of the rationale to select a beyond the floor level of control for new source PM emission values.

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 69

Comment: EPA presents CO limits in units of ppm, not lb/mmbtu as they are usually specified in emissions permits. We back calculated what EPA's CO limits were in terms of lb/mmbtu (heat input basis) by reversing the formula that EPA provides for estimating output-based limits from input-based limits, and applying this to EPA's output-based limits provided in the major source rule. [See submittal for table of lb/mmbtu CO rates.]

All the facilities in our database are classified as stokers (wet) or FB.

In our database, there are 50 facilities with permits that specify a CO emission rate, which range from 0.027 to 0.6 lb/mmbtu. CO is very hard to control in biomass burners, but nonetheless,

most facilities still claim they will control it using "good combustion practices". There are 9 facilities (marked in red on the graph below) that state they will use an oxidation catalyst for CO control. [See submittal for graph.] Many facilities that do not proposed to use an oxidation catalyst nonetheless are permitted at CO emission rates similar to those promised at facilities that do use a catalyst.

The stoker and fluidized bed categories are the types of boilers found in the permit database. There is a big difference in the new unit CO emission rates between stoker and fluidized bed boilers in EPA's rule. The graph below suggests that the stokers with the very lowest CO rates do tend to be fluidized bed units. [See submittal for graph.] However, there are a number of BFB's that are permitted with CO emission rates considerably lower than the limit of 0.19 lb/mmbtu that EPA has proposed. Further, while stoker units do appear to be using oxidation catalysts to achieve the lowest rates, there are some stokers that are not proposing to use oxidation catalysts that will achieve a CO rate comparable to a BFB. The bottom line: EPA's new source performance standards for stokers and BFB's do not appear to represent anything close to the best/lowest rates.

Response: For general discussion on Stoker and Fluidized Bed emissions being similar for biomass and/or bio-based solid fuel combustion, please see comment EPA-HQ-OAR-2002-0058-3511-A1, excerpt 65. The MACT floor emission limits for this rule were calculated from top performer emissions data reported in the EPA ICR Databases. No external data nor any enforceable permit limits were considered in the calculation of the emission limits. In fact, both the best performing units for CO emissions in the wet biomass stoker and biomass fluidized bed subcategories used to establish the MACT floor have CO emissions lower than the lowest permitted CO limits listed in the comment for those types of boilers. The commenter did not submit the actual database that they refer to: so we are unable to determine if any of these units have actually been constructed or whether we may already have data and information on any in the EPA database. Further, the summary information show that even within the permitted new units there is considerable variation which we account for in our MACT floor analysis on the best performing unit.

3G11. MACT Floor Results: New Dry Biomass – Stoker/Sloped Grate/Other

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 74

Comment: The floor for new stokers burning kiln-dried wood in the rule is 0.32 lb/mmbtu; EPA's own AP-42 document shows filterable PM10 emissions of 0.36 lb/mmbtu for dry wood combusted with no emissions controls. The AP-42 document further shows that use of just a mechanical collector (which relies on centrifugal force to spin out large particles) reduces the emissions to 0.3 lb/mmbtu for dry wood. [See submittal for AP-42 excerpt table.]

Response: EPA first notes that the final rule PM limit for new stokers burning kiln-dried biomass is 0.03 lb/mmBtu, based on EPA's beyond-the-floor analysis. Further, this rule regulates emissions of total filterable PM, of which PM10 represents only a portion of the total

emission profile. Emissions of PM10 characterize only those particles for which the diameter is less than 10 microns. Total filterable PM emissions are known to contain particles with diameters both larger and smaller than 10 microns.

3G14. MACT Floor Results: New Light Liquid

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 23

Comment: In its Petition for Reconsideration, CIBO stated that the CO limit in Boiler MACT for oil fired units was unachievable. The CO limits are still unachievable in some cases and these standards do not meet the CAA requirement that they be achievable by existing units.

Response: The EPA acknowledges this comment. The CAA requires that the emission limits be no less stringent than the average emission limitation achieved by the best performing 12% of units in the subcategory for existing units and the emission control achieved by the best controlled similar source for new units. The CO emission limits are based on CO levels achieved by the best performing units.

3H. Beyond-the-Floor: TSM8 at Existing Fuel Cells

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 50

Comment: New and modified sources subject to section 165 must install “the best available control technology” (BACT) for a number of criteria pollutants regulated under the CAA. There is nothing in the plain text of the CAA or its legislative history that suggests that Congress intended the maximum achievable control technology, which applies to emissions of highly toxic and carcinogenic pollutants, to be less stringent than the best available control technology, which applies to criteria pollutants. Indeed, for new sources it is clear that Congress intended MACT to be at least as stringent as the lowest achievable emission rate (LAER), which is generally recognized as being more stringent than BACT. Significantly, EPA fails to set standards based on the degree of reduction that can be achieved through the use of fabric filters, electrostatic precipitators, wet scrubbers, and other control technologies that the agency has identified as BACT, even though the agency has necessarily determined that these technologies are both technologically and economically achievable. EPA’s apparent position that control technologies that have been employed for decades for control of criteria pollutants are not achievable within the meaning of § 112 effectively reads the central component of section 112 – its requirement for MACT standards – out of the statute.

Response: As the commenter is aware, all standards established pursuant to section 112 of the CAA must reflect MACT, the maximum degree of reduction in emissions of air pollutants that the Administrator, taking into consideration the cost of achieving such emissions reductions, and

any nonair quality health and environmental impacts and energy requirements, determines is achievable for each category. The CAA specifies that MACT for new boilers and process heaters shall not be less stringent than the emission control that is achieved in practice by the best-controlled similar source, as determined by the Administrator, which EPA has defined as the lowest emitting source in this rulemaking, with an appropriate consideration of variability. This minimum level of stringency is the MACT floor for new units. However, EPA may not consider costs or other impacts in determining the MACT floor. EPA must exercise its judgment, based on an evaluation of the relevant factors and available data, to determine the level of emissions control that has been achieved by the best controlled similar source under variable conditions. The DC Circuit Court of Appeals has recognized that EPA may consider variability in estimating the degree of emission reduction achieved by best-performing sources and in setting MACT floors. *See Mossville Env'tl Action Now v. EPA*, 370 F.3d 1232, 1241–42 (DC Cir 2004) (holding EPA may consider emission variability in estimating performance achieved by the best-performing source and may set the floor at level that best-performing source can expect to meet “every day and under all operating conditions”).

We disagree that we failed to set standards based on the degree of reduction that can be achieved through the use of fabric filters, electrostatic precipitators, wet scrubbers, and other control technologies that the agency has identified as BACT. In all cases, the emission limits for new sources in the final rule are based on the best controlled similar source which is defined as the lowest emitting. The analysis of the cost of achieving those limits is in fact based on the control technologies cited by the commenter. Moreover, BACT determinations cannot be compared to a MACT standard that is established based on the best performers for each subcategory nationwide, since BACT determinations are specific to individual units. Further, section 112(d)(3)(A) states that in determining the best performing 12 percent of existing units, sources that are achieving lowest achievable emission rate (LAER) should be excluded. Nevertheless, in the June 4, 2010 proposal, we did consider various regulatory options more stringent than the MACT floor level of control for both existing units (75 FR 32026) and new units (75 FR 32029). In this final amended rule, we reviewed the emission levels that became less stringent since the March 2011 final rule in order to assess whether a beyond-the-floor option was technically achievable and cost effective. See memorandum “Beyond the Floor Technology Analysis for Major Source Boiler and Process heaters (revised August 2012)” in the docket.

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 49

Comment: On reconsideration, EPA is proposing to revise its standards, but again fails to set or even consider limits reflecting the maximum degree of reduction that can be achieved through the use of control technology. Instead, EPA only adopts “beyond the floor” limits where its flawed calculation procedure leads to new source MACT floors (allegedly based on the best performing unit) that are less stringent than existing source MACT floors (allegedly based on the top 12 percent). However, even in these circumstances, EPA does not evaluate available technologies and establish limits reflecting the degree of reduction that can be achieved. EPA merely employs what it styles “beyond the floor” authority to raise the new source MACT limit to be equal to the existing source limit. EPA’s failure to set standards reflecting the maximum

achievable degree of reduction in emissions and its failure even to consider standards based on the use of available control measures such as fabric filters, wet scrubbers, activated carbon injection, and switching to cleaner fuels is unlawful and arbitrary.

Response: For response to the claim that EPA has failed to set or consider limits reflecting the maximum degree of reduction that can be achieved through the use of control technology, please see comment EPA-HQ-OAR-2002-3511-A1, excerpt 50.

As the commenter is aware, the EPA must consider cost, non-air quality health and environmental impacts, and energy requirements in connection with any standards that are more stringent than the MACT floor (beyond-the-floor controls). EPA's beyond the floor analysis did evaluate these factors in determining whether it was appropriate to establish more stringent standards. Moreover, while section 112(d) allows existing source MACT floor limits to be less stringent than new source limits, the Agency interprets this provision as precluding the new source limits from being less stringent than the existing source limits. Thus, it is appropriate to set the new source limit to be no less stringent than the existing source limit.

3Z. Out of Scope - MACT Floor Analysis

Commenter Name: Regina Hopper

Commenter Affiliation: America's Natural Gas Alliance (ANGA)

Document Control Number: EPA-HQ-OAR-2002-0058-3444-A1

Comment Excerpt Number: 1

Comment: ANGA submitted comments (dated August 23,2010) to EPA regarding the proposed ICI Boiler MACT Rules, as well as comments (dated July 15,2011) regarding the Agency's reconsideration of the final ICI Boiler MACT Rules. We resubmit, in their entirety, both sets of comments for the Agency's consideration.

We are deeply concerned that EPA has failed to incorporate in its analyses the recent, best available data and information regarding technology, the state of the natural gas market and natural gas infrastructure and in particular the dramatic expansion in the supply of domestic natural gas since 2007, in determining the cost-effectiveness of using natural gas as a fuel choice for boilers and process heaters.

ANGA believes that this rule, like other rules promulgated by the Agency, should reflect the use of the best data and science that is available, and the ongoing reconsideration presents an opportunity for EPA to do so. We therefore reiterate our request that the Agency look more closely at the comments that we have submitted previously, and the data and information underlying those comments, as it reconsiders the ICI Boiler MACT Rules, and requests that it look specifically at the issues identified in those comments as part of its broader reconsideration of the entire rule.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Regina Hopper
Commenter Affiliation: America's Natural Gas Alliance (ANGA)
Document Control Number: EPA-HQ-OAR-2002-0058-3444-A1
Comment Excerpt Number: 2

Comment: Even if EPA, after conducting an appropriate analysis using the best available data, does not revise its conclusion to establish a revised beyond-the-floor standard that considers use of natural gas as an appropriate control technology, some owners and operators may find that converting to natural gas-based generation is a cost-effective compliance strategy. As set forth in our comments, ANGA is concerned that EPA cited excessive cost and supply constraints as the basis for its current conclusions without rigorous review of the most recently available data. Therefore, it is very important that EPA, at a minimum, recognize and put forth accurate assumptions associated with natural gas availability and costs so that the public as well as owners and operators of boilers are not misled by inaccurate and misleading information disseminated by the Agency.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Regina Hopper
Commenter Affiliation: America's Natural Gas Alliance (ANGA)
Document Control Number: EPA-HQ-OAR-2002-0058-3444-A1
Comment Excerpt Number: 3

Comment: In comments dated August 23, 2010, regarding the proposed ICI Boiler MACT Rules, we, along with the American Gas Association (AGA), specifically requested that the Agency take into consideration the most recent and best science, information and data with respect to fundamental issues such as the significantly lower level of HAP emissions from natural gas-fired boilers and the ability of the industry to provide natural gas to ICI boilers in light of current natural gas supply and infrastructure conditions (see pages 9-14 of ANGA's August 23, 2010 comments, which are attached, for a summary and discussion of these issues). We note that AGA has filed comments on the Boiler MACT reconsideration and we hereby endorse those comments, dated July 5, 2011.

Based on our review of the ICI Boiler MACT Rules, and the Response to Comments document, we are very disappointed that EPA failed to consider the dramatic expansion in the supply of domestic natural gas since 2007. We encourage the Agency, as part of this reconsideration process, to consider and incorporate in its analyses the recent, best available data as well as the potential cost-effectiveness implications this abundant supply would have on the choice to use natural gas as a fuel for boilers and process heaters. The Agency response to comments¹ fails to provide any explanation as to how the Agency considered or incorporated the best available data in its final proposal. The Agency's entirely conclusory statement, and the absence of such an explanation or incorporation of the data in revised analyses, raises concerns as to whether the standard set by the Agency in the final rule is based on best available data or supported by the administrative record.

[Footnote]

(1) "EPA has reviewed the camp/ex details cited by the commenter, such as the country's pipeline and storage network capacities. However, the EPA decision that fuel switching is inappropriate remains unchanged"

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Melvin E. Keener

Commenter Affiliation: Coalition for Responsible Waste Incineration (CRWI)

Document Control Number: EPA-HQ-OAR-2002-0058-3454-A1

Comment Excerpt Number: 5

Comment: Emission limits and MACT floor methodology.

EPA proposes to make changes to a number of emission limits, including the Hg limits, as well as making some minor adjustments to their floor setting methodologies. See *e.g.*, 76 Fed. Reg. at 80610 – 80614. When doing so, CRWI suggests that EPA take note of the D.C. Circuit Court of Appeals most recent MACT related decision, *Portland Cement Association v. EPA* (D.C. Cir. 2011) in which Judge Brown wrote a compelling concurrence questioning the Agency's reliance on a previous case, *Sierra Club v. EPA*, 479 F.3d 875, 883 (D.C. Cir. 2007), (also known as *Brick MACT*) for support of EPA's "lowest emission" floor-setting methodology.

In *Brick MACT* the court seemed to uphold the concept that EPA was justified in using the lowest levels emanating from a source to set the regulatory limits, regardless of how that level was achieved. However, in doing so, as Judge Brown notes, the *Brick MACT* court erroneously interpreted a prior decision (*National Lime Association v. EPA*, 233 F.3d 625, 631 – 633, D.C. Cir. 2000) (also known as *NLA II*) relating to the Portland Cement MACT.

In that case, the court held that EPA could not refuse to set standards because sources did not use air pollution control technology to control emissions. Later in the opinion, when deciding a challenge from the National Lime Association ("NLA"), the court rejected NLA's argument that particulate matter ("PM") was not a proper surrogate for setting a standard and wrote the language that prompts EPA's erroneous interpretation. The *NLA II* court noted that controlling PM actually controls hazardous air pollutant ("HAP") metals stating:

According to the NLA, this methodology requires the agency to set a floor of "no control" for HAP metals because no cement plant intentionally controls HAP metals; metal emissions are controlled only incidentally by controls placed upon PM. The EPA's response is the correct one: "cement plants actually *are* controlling HAP metals[,] intentionally or not. *Id.* at 640.

Thus, the *NLA II* court was not saying that control does not matter. Instead, the court was explaining that *as long as control is being achieved*, intent to control does not matter. Therefore, if a source is controlling one pollutant and that control also limits another pollutant, the Agency can consider the performance data for that second pollutant as well. Thus, EPA may not use just any emissions data to select best performers. It must be emissions data for pollutants that are being controlled.

Judge Brown makes the same conclusion. In her concurrence she notes:

Sierra Club [*Brick MACT*] relied on our holding in *National Lime Ass'n v. EPA*, 233 F.3d 625, 640 (D.C. Cir. 2000), that the CAA does not require "that [the] achievement . . . be the product of a specific intent." But I do not read *National Lime* to have held that the achievement need not be the product of *any* intent. Instead, context reveals that the *National Lime* Court was referring to emissions of one sort that are "controlled only incidentally by controls placed upon" another sort of emission. *Id.* The incidental control of one emission as the result of controlling another still certainly counts as an "achievement" of emission control. But the Court did not state—or even imply—that emissions levels determined by inputs alone count as an "achievement" of emission control within the meaning of the statute.

Thus, Judge Brown cast considerable doubt on the astuteness of the *Brick MACT* panel's analysis of prior cases. Continuing on, Judge Brown declared that:

Our holding in *Sierra Club* was a self-inflicted wound, and the result of a series of interpretive leaps that I simply cannot follow. I regret that we have ignored Congress's wishes and made life more difficult—for industry and its employees, for EPA, and for ourselves.

CRWI, therefore, urges EPA to avoid perpetuating this "self-inflicted" wound, and to avoid putting too much credence in the *Brick MACT* decision.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Lenny Dupuis

Commenter Affiliation: Dominion Resources Services, Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3486-A1

Comment Excerpt Number: 12

Comment: The limits established in the March 2011 final rule and proposed in this reconsideration rulemaking for industrial boilers burning biomass are a substantial improvement relative to the original (May 2010) proposed rule. In comments submitted in response to the May 2010 proposal, several technical issues associated with the methodology used in setting the MACT standards were identified that EPA has considered and improved upon in the March 2011 final rule and this reconsideration proposal with more reasonable PM limits and additional subcategorization of biomass units. Nevertheless, we remain concerned that the revised limits will inhibit the combustion of biomass in the future and could discourage companies from combusting biomass over more traditional fossil fuels, making it increasingly difficult for companies to meet RPS and GHG requirements and/or reduction goals. The cost of adding controls for biomass could be extensive, potentially inhibiting the development of new biomass facilities.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Peter Pagano

Commenter Affiliation: American Iron and Steel Institute (AISI)

Document Control Number: EPA-HQ-OAR-2002-0058-3490-A1

Comment Excerpt Number: 27

Comment: EPA should ensure that affected sources can comply with any imposed obligations under the boiler MACT.

EPA must reconcile the fact that carbon monoxide standards may not be achievable for units required to use low nitrogen oxide-burner technology.

The proposed CO emission limits included in the MACT floor do not adequately account for the effect of low NO_x technology on CO emission rates. Existing low-NO_x burner (LNB) technology relies on lower burner temperatures to suppress NO_x formation, which often increases the CO emission rate. While some LNB applications can be managed to simultaneously minimize CO, many cannot. Burning additional natural gas or other fossil fuels in an afterburner to control CO does not solve the problem because these fuels contribute NO_x to the exhaust stack putting the source at risk of violating the applicable NO_x limit. With the increased use of low-NO_x technology in response to evolving environmental regulations under the Cross State Air Pollution Rule (CSAPR), Regional Haze, NAAQS (e.g., NO₂, Ozone, PM_{2.5}), NSPS, etc., demonstrating compliance with CO limits in Boiler MACT may increasingly conflict with other Clean Air Act requirements.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Ashok K. Jain

Commenter Affiliation: National Council for Air and Stream Improvement, Inc. (NCASI)

Document Control Number: EPA-HQ-OAR-2002-0058-3505-A1

Comment Excerpt Number: 18

Comment: Good combustion practice (GCP) consists of operating a combustion or incineration device at high enough temperature, with adequate residence time, and allowing for good mixing with oxygen. GCP will minimize the formation of products of incomplete combustion (PICs). The US EPA has historically approached the control of PICs by regulating combustion efficiency rather than mandating emission limits for PICs. One method by which combustion efficiency is traditionally judged is by monitoring the level of carbon monoxide (CO) in the combustion flue gases.

In general, when burning fossil fuels in boilers, a level of 100 to 200 ppm CO in the flue gas is believed to be achievable and consistent with GCP. However, in the forest products industry (FPI) the burning of wood or wood-derived fuels, by themselves or in combination with other fossil fuels, involves very different combustion conditions than the burning of fossil fuels alone. The high moisture content typical of most wood-derived fuels requires a larger than usual area of refractory surface to dry the fuel before combustion. Sufficient secondary air must be supplied over the fuel bed to burn the volatiles that account for most of the combustible material in the fuel. Further, the air should not be so excessive as to cool the combustion flame (which also results in increased CO and PICs). As a result of these differences, well operated biomass boilers have significantly higher levels of CO than well operated fossil fuel-fired boilers.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 76

Comment: *EPA Is Justified In Using Emissions Data From Five Sources To Determine The Existing Source MACT Floor For Subcategories With More Than 30 Sources Where Emissions Information On Less Than 30 Sources Are Available*

The above tables point out that in several cases, EPA is using less than 5 sources to set MACT floors. EPA has explained that it is using the top 12 percent of sources for which data are available where there are more than 30 sources in a subcategory. EPA should use no fewer than 5 sources in setting the MACT floor for any source category – regardless of the number of sources in the category or subcategory. The language of § 112(d)(3)(A) shows that Congress clearly expected enough emissions information to be available for categories or subcategories with 30 or more sources so that more than 5 sources would be used in selecting the top 12%. It makes no sense for Congress to specify a minimum number of sources, i.e. 5, for source categories or subcategories with less than 30 sources, but allow EPA to establish standards based on less than 5 sources for larger source categories. Using no less than 5 sources at all times would comport with the clear intention of Congress.

ACC also notes that the word "sources" as used in the last clause of §§ 112(d)(3)(A) and (B) is ambiguous and, therefore, susceptible to reasonable interpretation by the Agency. As EPA explains in the preamble, the word "sources" might be construed to refer to all sources in the given category or subcategory. However, the word "sources" in the first clause of §§ 112(d)(3)(A) and (B) clearly refers to the sources for which EPA has emissions information. Notably, the second use of the word "sources" in § 112(d)(3)(A) also clearly is a reference to sources for which EPA has emissions information. So, it is reasonable to conclude that Congress intended the word "sources" to have a consistent meaning for all purposes under these provisions. In other words, the reference "30 or more sources" at the end of § 112(d)(3)(A) and "fewer than 30 sources" at the end of § 112(d)(3)(B) reasonably should be construed as a reference to sources for which EPA has emissions information. This interpretation allows for EPA to naturally reconcile the application of §§ 112(d)(2)(A) and (B) such that the number of sources for which EPA has emissions information in a given category or subcategory dictates whether § 112(d)(2)(A) or (B) should apply.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 18

Comment: The Courts have said in *dicta* that in developing standards for new sources based on the performance of a single unit, it may be reasonable for EPA to set MACT limits that reflect the performance of emission units "under most adverse circumstances which can reasonably be expected to recur." This suggestion has been adopted by EPA and is well known to industry. For most pollutants the most adverse circumstance is full load operation of the unit and most compliance testing is done at 90 to 100 percent of full load operation. In its instructions to industry EPA did not require sources to test under less stringent conditions and was clear that it intended to use the results to establish MACT floors. EPA did not supervise the testing. Under these circumstances it would seem reasonable to assume that sources, who are in the best position to determine those "representative" operating conditions that would produce the highest emissions have, in fact, done so and submitted data reflecting the most adverse circumstances that can reasonably be expected to occur. For this reason, we believe that before EPA assigns any additional factor for adverse operating conditions, it should produce some objective basis, such as a showing that a particular test or set of tests was conducted under less stringent conditions, for determining that any additional adjustments are appropriate.

Response: We disagree with the assumption that sources would conduct tests under operating conditions reflecting the most adverse circumstances that can reasonably be expected to occur. Most data obtained during the ICR process were the results of compliance tests conducted to show compliance with permit conditions, and sources are unlikely to conduct such testing under the most adverse conditions since they would want emissions to be as low as possible to ensure that compliance is demonstrated. Even under the tests specifically required by the ICR, facilities would be reluctant to operate under conditions that are more adverse than the required testing at typical operating load, because to test at adverse conditions would require the facility to perhaps detune the control device and boilers, which could result in emissions that violate their operating permits. In addition to the emission test data, we required that facilities record and report the following process information taken during the 30 day period before, at the time of, and during, the emissions test: Heat input; fuel composition and feed rate; steam output; emissions control devices in use during the test; control device operating or monitoring parameters (including, as appropriate to the control device, flue gas flow rate, pressure drop, scrubber liquor pH, scrubber liquor flow rate, sorbent type and sorbent injection rate), and process parameters (such as oxygen). This was to ensure that we were aware of both the boiler and control device operation during the test and how it related to normal operation for the boiler and control device. Also, we had multiple tests from many of the best performers. Most of the facilities tested as part of the ICR had previously submitted test results. The multiple test results from these units show variability. However, we identified the best performers based on the single lowest 3-run test average and used the other test results to account for variability. Furthermore, the commenter did not provide any information to support its assertion that the most adverse conditions were used in testing.

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 19

Comment: There is nothing to suggest that the Court intended an all out assault on compliance testing when it suggested that MACT limits should reflect the most adverse circumstances that

can reasonably be expected to occur. For several decades EPA has held out "reference method" compliance testing as the gold standard of environmental protection. EPA tells us that just one test every year, or every 5 years, is "sufficient to assure compliance" with pollution limits needed to protect public health. This is because its reference method testing is so accurate and the test conditions are so severe. In its enforcement actions EPA routinely defeats industry arguments about what a test result might have been and enforces based on the average of the three runs of a reference method test. When a defendant argues that a violation might be a "false positive", EPA's lawyers respond that in other matters there might just as well be "false negatives", where a dirty source has a serendipitous result and the Courts have ruled that a single result of a reference test is sufficient to characterize the emissions performance of the unit and establish a violation. Now, when convenient, EPA throws its carefully designed reference method tests under the bus and asserts that plant performance is so variable that emissions on any given day might be 100 times greater than demonstrated in a compliance test. The actual result of the reference method test of best performing unit(s) plays no meaningful part in EPA's MACT floors. EPA's proposed floors are based on calculations of what test results might have occurred at a given unit. Yet, for every unit in the top 12 percent whose emissions would increase on retesting there is another unit whose emissions would decrease. For this reason, the average of the top 12 percent would not change appreciably if the entire group were to be tested and retested. EPA should accept the results of reference testing for standard setting purposes, just as it does for compliance purposes.

We note that the Court has also raised a concern that standard setting and enforcement be consistent. Thus, to the extent that EPA utilizes statistical and other tests and assumptions in standard setting so as to ensure continuous compliance, it should apply those same tests and assumptions in the enforcement of those standards. Under EPA's proposed methodology, sources should be required to demonstrate, based on test results, fuel variability factors, instrument errors and scale errors, that the 99th percentile of their UPL is less than the standard adopted by EPA.

Because the flaws identified in the 2010 Comments and above show that EPA unlawfully and arbitrarily misrepresents the actual performance of individual sources, the agency's new source floors – which must reflect the emission level achieved by the single best performing source – are unlawful and arbitrary. EPA's misrepresentation of individual sources' performance also renders its floors for existing sources unlawful and arbitrary.

Response: EPA disagrees with the commenter that it interpreted compliance testing used to set the MACT floors inappropriately. This particular comment is referencing earlier concerns about EPA's use of a fuel variability factor and adjustments to data reported below detection levels in order to develop a standard that reflect a level achieved "under most adverse circumstances which can reasonably be expected to recur." EPA recognizes the importance of reference method testing in setting emission standards. However, EPA also identified other variations in best performers when looking at fuel variability (See response to comment under the HCl-Fuel Variability chapter DCN: EPA-HQ-OAR-2002-0058-3511-A1, excerpt number 15) and data reported below detection limit, especially in cases where the measurements made during the reference test methods were approaching the limits of detection of these methods (See responses to comments in Chapter Methodology: Non-Detect Values).

Commenter Name: Shannon S. Broome
Commenter Affiliation: Auto Industry Forum (AIF)
Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1
Comment Excerpt Number: 4

Comment: EPA Could Endorse a Petition Process for Unit-Specific CO Limits for Units That Cannot Implement Cost-Effective Modifications to Comply

In its comments, the Council of Industrial Boiler Owners ("CIBO") requests that EPA include in the final rule a provision allowing CO emissions limitations to be determined by state permitting authorities on a case-by-case basis. This provision would be available for boilers and process heaters that cannot attain the final rule CO emission limit without major unit redesign, oxidation catalyst addition with associated stack gas reheat and increased fuel usage, exceedance of an applicable NOX standard, or derating the unit. We concur with this recommendation.

EPA has broad authority to create subcategories and to distinguish among classes, types, and sizes of sources within a source category or subcategory. These authorities would even enable EPA to establish a subcategory for an individual source or a standard for an individual source within a category or subcategory, provided the Agency had a rational basis for establishing such a subcategory or standard. CIBO's recommended case-by-case approach to setting CO standards for certain individual sources is imminently reasonable and would be a proper exercise of such authority.

The essence of CIBO's argument is that certain individual sources are fundamentally different from most other sources in the industrial boiler source category with regard to CO emissions. As CIBO points out, CO emissions depend on unique boiler characteristics and it is simply not possible for certain boilers to meet a CO standard that is based on the performance of other boilers that do not share those unique characteristics. CIBO also points out that such incompatibilities are revealed, for example, when a particular boiler cannot meet the CO standard without fundamentally redesigning the unit or without derating the unit. In such cases, EPA reasonably can conclude that the particular boiler is fundamentally different and, therefore, a boiler-specific standard is reasonably justified.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Roger Martella
Commenter Affiliation: National Alliance of Forest Owners (NAFO)
Document Control Number: EPA-HQ-OAR-2002-0058-3519-A1
Comment Excerpt Number: 8

Comment: With respect to the remaining emissions limits included in the proposed Major Source (and CISWI) rule, NAFO urges EPA to consider both the necessity of imposing stringent emissions limits on biomass boilers from a public health perspective as well as the impact that expensive control technology will have in discouraging the use of this clean, renewable, and climate-beneficial energy source. While EPA's proposed emissions limits represent in some

cases an improvement over current standards, they do not go far enough in correcting the flaws in the current rule.

NAFO supports EPA's proposal to impose less stringent emissions standards on new biomass boilers. This proposal remains consistent with EPA's legal obligations under section 112 of the Clean Air Act, while removing compliance-based barriers to bioenergy development. With the exception of mercury, which is discussed above, the proposed emissions limits for new boilers represent a marked improvement over current standards and, at a minimum, we urge EPA to adopt these standards.

Nevertheless, in order to properly reflect the health and climate benefits of biomass and provide proper incentives for the continued development of this important source of energy, EPA must make additional modifications beyond its current proposals. Therefore, we reiterate and incorporate herein our previous comments urging alternative and less stringent emissions limitations for biomass boilers and incinerator units.²⁸

[Footnote 28: NAFO Major Source Rule Comments at 7,9.]

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Roger Martella

Commenter Affiliation: National Alliance of Forest Owners (NAFO)

Document Control Number: EPA-HQ-OAR-2002-0058-3519-A1

Comment Excerpt Number: 10

Comment: We urge EPA to adopt more reasonable emissions limits for CO and PM that are less stringent and less costly, but still achieve statutory requirements. Again, the costs required to meet the proposed emissions limits are unreasonably high in comparison to the public health and environmental benefits that will accrue. EPA can encourage, rather than discourage, the use of clean, renewable biomass fuels by imposing less stringent standards that will still comply with EPA's statutory mandates under the Clean Air Act ensure that high compliance costs are not imposed on the industry unless commensurate health benefits are provided.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 49

Comment: Although we believe that a full load CO stack test followed by 30-day average oxygen monitoring is a workable compliance approach for many large industrial boilers with sophisticated combustion control systems (e.g., automated oxygen trim systems), more flexible approaches are needed to accommodate a certain subset of sources. In addition to the proposed adjustments to the CO emissions limitations and the proposed alternative CO emissions

limitations for units with CEMS, EPA should consider additional alternative approaches to setting standards for CO and the accompanying ongoing compliance requirements. Discussed below are several additional alternative approaches. Each approach is well within EPA's authority to adopt, the approaches are not mutually exclusive, and each would result in emissions limitations that better reflect the limitations of the available data and better accommodate variability that even the best performers unavoidably exhibit.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Dean C. DeLorey

Commenter Affiliation: The Amalgamated Sugar Company LLC (TASCO)

Document Control Number: EPA-HQ-OAR-2002-0058-3522-A1

Comment Excerpt Number: 5

Comment: The proposed emissions standards also fail to account for the inherent variability of emission control systems and trace metal concentrations in fuel supplies. Emissions tests are only a "snap shot" in time and do not reflect all potential operating scenarios. Emissions standards need to reflect worst case scenarios including the maximum trace metal concentrations in the fuel supply. Please revise the emissions standards accordingly.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Ahmed Idriss, Capital Power Corporation

Commenter Affiliation: CPI USA North Carolina (CPI NC)

Document Control Number: EPA-HQ-OAR-2002-0058-3524-A1

Comment Excerpt Number: 4

Comment: CPI NC does not support the EPA's use of single tests to determine MACT floors. According to the Eastern Research Group (ERG) memo to EPA dated November 2011, 75% of the data included in the calculation of HCl MACT floor for solid fuel are based on a single test. Similarly, 50% of the data for PM for Stokers/Sloped Grate/Other Wet Biomass Units were obtained through single tests. *Id.* This use of single tests to determine MACT floors is statistically unsound due to the highly variability of fuel and operating conditions, particularly for multi-fuel blend facilities.

CPI NC recommends that EPA consider using multiple tests to establish the appropriate MACT floors. CPI NC believes that the use of single tests is unreasonable, and that the use of multiple tests would lead to a more accurate and representative MACT floor.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Mary Sullivan Douglas

Commenter Affiliation: National Association of Clean Air Agencies (NACAA)

Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1

Comment Excerpt Number: 1

Comment: Under sections 112(d)(2) and 129(a)(2) of the CAA emission limits for existing sources must reflect the maximum degree of reduction in emissions that the EPA Administrator determines is feasible (Maximum Achievable Control Technology or “MACT”) **and** shall not be less stringent than the average emission limitation achieved by the best performing 12 percent of sources (for which the Administrator has emissions information) (the “MACT floor”). EPA concludes that recent court decisions require that (a) floors for existing sources must reflect the average emission limitation achieved by the best-performing 12 percent of existing sources; (b) a MACT floor cannot be “no control”; (c) EPA cannot ignore non-technology factors that reduce HAP emissions and (d) the levels of HAPs in fuels consumed by sources must be reflected in the MACT floor determination.¹

EPA has proposed to use an array of calculations, adjustments and defaults to determine the new and existing MACT floors and has provided most of the calculations underlying its proposed floors. Our review of the detailed calculation process leads us to conclude that EPA’s approach is flawed in several significant respects and in almost every instance overstates the variability in emissions performance that is shown in EPA’s data set and other readily available information. These inflated calculations have resulted in the establishment of excessively lenient MACT floors. Ironically, for a few subcategories, EPA inexplicably failed to provide any allowance for variability or arbitrarily assigned a variability that is far too low to account for expected operational differences in performance over time.

[Footnote]

(1) A source that is a low emitter because of low levels of HAP in its fuel can still be a “best performer” whose emission levels are part of the “average of the best performing 12 percent.”

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Mary Sullivan Douglas

Commenter Affiliation: National Association of Clean Air Agencies (NACAA)

Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1

Comment Excerpt Number: 3

Comment: Where EPA has data from testing at levels of precision sufficient to determine the actual variation in performance of a reasonably significant number of units, and where the agency’s approach to identifying the “best performing units” does not skew the results too significantly, the resulting calculations lead to proposed limits that would lead to significant emission reductions from some of the highly polluting subcategories. However, where these factors are not present, EPA’s procedures and assumptions lead to gross overestimates of the variability in performance of the best performing units and proposed emission limits that are higher than current emissions. Such limits simply create testing and paperwork burdens without providing any public health benefit. Moreover, these limits clearly do not meet the requirements of section 112 and are likely to lead to additional litigation that delays reduction in HAP emissions from the entire sector.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Mary Sullivan Douglas

Commenter Affiliation: National Association of Clean Air Agencies (NACAA)

Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1

Comment Excerpt Number: 42

Comment: New and modified sources subject to section 165 of the CAA must install “the best available control technology” (BACT) for a number of criteria pollutants regulated under the CAA, including, as relevant here, CO, sulfur dioxide (“SO₂,”), nitrogen oxide (“NO_x”) and mercury. In the proposed rules EPA is setting limits for certain pollutants based on the application of “the maximum achievable control technology.” There is nothing in the plain text of the CAA or its legislative history that suggests that Congress intended MACT, which applies to emissions of highly toxic and carcinogenic pollutants, to be less stringent than BACT, which applies to criteria pollutants. Indeed, for new sources it is clear that Congress intended MACT³⁹ to be at least as stringent as the lowest achievable emission rate (LAER), which is generally recognized as being more stringent than BACT.

Regulatory authorities are to consider costs when establishing both BACT and MACT limitations that are more stringent than the MACT floor. There is nothing in the CAA that speaks to how EPA and permitting authorities must weigh costs against other considerations in establishing BACT. However, there has been a substantial body of precedent that speaks to this issue. In contrast, in establishing a requirement for a MACT floor, Congress effectively set a floor on what should be considered reasonable costs for MACT control technologies. Since MACT may be no less stringent than the performance level of the best-performing 12 percent, the costs to those sources of achieving that level of performance (including the worst-performing unit within a subcategory) must be within what was considered to be appropriate for MACT sources in that subcategory. This is of particular relevance to the set of rules under consideration, where the cost of control for similarly situated units is essentially the same but the calculated MACT floors are substantially different.

In its MACT determinations EPA needs to explain how an emission limit imposed for a unit subject to section 129 (and therefore presumably meeting the reasonable cost test for MACT) is not reasonable for an identical unit subject to section 112.

[Footnote]

(39) The MACT floor definition is essentially the same as the definition of LAER, which applies to new and modified sources in nonattainment areas.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Linda Miller

Commenter Affiliation: New Jersey Department of Environmental Protection (NJDEP)

Document Control Number: EPA-HQ-OAR-2002-0058-3664-A2

Comment Excerpt Number: 2

Comment: We recommend that emission limits for a boiler and process heater located at an area HAPS source be the same as limits for the same size unit located at a major HAPS source.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Pamela Lacey

Commenter Affiliation: American Gas Association (AGA)

Document Control Number: EPA-HQ-OAR-2002-0058-3672-A2

Comment Excerpt Number: 6

Comment: One of AGA's chief concerns about previous versions of the major source Boiler MACT rule and preambles was that the agency appeared to be relying on an outmoded assumption about the availability of natural gas supply in the market. EPA's previous statements implied that there might be a shortage of supply that could lead to "curtailments." This is a thing of the past. With the advent of shale gas production, natural gas supplies are abundant and market prices are low and stable, as we explained in our comments on previous proposals in this docket and in our petition for reconsideration. We very much appreciate the proposed definition of "period of gas curtailment or supply interruption" stating that this is a "period of time during which the supply of gaseous fuel to an affected facility is halted for *reasons beyond the control of the facility*" and not because the facility owner the owner opts to enter into a contract with the utility to purchase natural gas at a lower price in exchange for a contractual agreement that the operator would accept switching off of natural gas during periods of high peak demand or the facility owner opts to switch fuels in order to obtain a lower price "due to normal market fluctuations not during periods of supplier delivery restriction." Proposed section 63.7575, 76 Fed. Reg. at 80653.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Douglas Emerson et al.

Commenter Affiliation: American Crystal Sugar Company et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3675-A2

Comment Excerpt Number: 3

Comment: It was found that the database did not include any information for the following affected sources:

- MIMISugarSebewaing Boiler #3
- NDMinnDakFarmers Boiler #6
- MNAmericanCrystalCrookston Boiler #2
- MNAmericanCrystalCrookston Boiler #3

- MNAmericanCrystalMoorhead Boiler #3
- MNAmericanCrystalEastGrandForks Boiler #1
- MNAmericanCrystalEastGrandForks Boiler #2

Considering that the emissions information for the boilers was submitted on information collection spreadsheets provided by the EPA and that a single spreadsheet contained information for multiple boilers at a given facility, the exclusion of certain boilers from the 2008 survey database is particularly troubling. Using data submitted by American Crystal Sugar Company as an example, information for nine boilers was submitted, but only four boilers were included in the 2008 survey database. This means only 44 percent of the submitted data was used in development of final emission limitations that are required to be based on a ranking procedure of all operating boilers for a given subcategory. If only 44 percent of the submitted data was included for American Crystal Sugar Company sources, an important question is raised to the inclusion of other source data.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Douglas Emerson et al.

Commenter Affiliation: American Crystal Sugar Company et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3675-A2

Comment Excerpt Number: 5

Comment: As indicated in other comment letters, such as the U.S. Beet Sugar Association letter submitted under separate letterhead, lack of variability reflected in the proposed emission standards is of concern. As quoted in this letter, "The D.C. Circuit has held that variability, particularly in emission controls, must be accounted for when setting MACT standards. According to the D.C. Circuit, the CAA's statutory requirements for setting the MACT floor authorize EPA to set a standard which reflects what the best performing units can achieve under the 'worst reasonably foreseeable circumstances'".

The issue of variability in operations for industrial boilers is of great concern. Industrial boilers operate under a wide variety of conditions that may impact emissions at any given time, such as load swings and fuel quality changes to name a few. A final emission limitation based on a single test value for any boiler has a very low probability of repeatability. To highlight this fact, additional particulate matter test data for the American Crystal Sugar Company Crookston facility was obtained during further analysis and strategic planning for MACT compliance since the 2008 data submittal. It was found for each of the three existing boilers that results varied by as little as a factor of 2 and as much as a factor of 16 in two subsequent rounds of performance tests. This high degree of variability must be reflected in the proposed emission limits by establishing a final limit that accounts for the worst reasonably foreseeable circumstances with regard to repeatability. Therefore, when only one performance test is available, the highest individual test run result should be used, not the average, and certainly not the lowest test result. When multiple tests are available for a given unit, the highest result should be used. This will not account for all operational variability, but at least may provide for some level of compliance assurance.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Douglas A. McWilliams

Commenter Affiliation: American Municipal Power

Document Control Number: EPA-HQ-OAR-2002-0058-3685-A2

Comment Excerpt Number: 29

Comment: EPA Is Justified in Using Emissions Information from At Least Five Sources to Establish MACT Floors for Existing Sources

For many subcategories with more than 30 units, including the existing pulverized coal subcategory, EPA established the MACT floor using data from less than 5 units. That approach contradicts the primary structure of section 112(d). When drafting the 1990 Amendments to the Clean Air Act, Congress carefully established distinct approaches for establishing the MACT floors that would apply to existing and new sources. For existing sources, Congress established two alternate approaches in sections 112(d)(3)(A) and (B). Where there are "30 or more sources" in a subcategory, section 112(d)(3)(A) instructs EPA to select "the average emission limitation achieved by the best performing 12 percent of the existing sources." Similarly, where there are "fewer than 30 sources" in a subcategory, section 112(d)(3)(B) requires use of "the average emission limitation achieved by the best performing 5 sources" Both of these provisions were designed to ensure that a *group* of existing sources are used to establish the emissions limits for existing sources. In contrast, section 112(d)(3) specifies that the MACT floor "for new sources in a category or subcategory shall not be less stringent than the emission control that is achieved in practice by the *best controlled similar source* . . ." Thus, new source limits are to be set by a single source while existing source limits were to be set by reference to a group of representative peers. The Proposed Rule would cross that clean statutory line by treating existing sources functionally the same as new sources in some subcategories. Furthermore, the word "sources" in the first clause of §§ 112(d)(3)(A) and (B) clearly refers to the sources for which EPA has emissions information. Notably, the second use of the word "sources" in § 112(d)(3)(A) also clearly is a reference to sources for which EPA has emissions information. So, it is reasonable to conclude that Congress intended the word "sources" to have a consistent meaning for all purposes under these provisions. In other words, the reference "30 or more sources" at the end of § 112(d)(3)(A) and "fewer than 30 sources" at the end of § 112(d)(3)(B) reasonably should be construed as a reference to sources for which EPA has emissions information. This interpretation allows for EPA to naturally reconcile the application of §§ 112(d)(2)(A) and (B) such that the number of sources for which EPA has emissions information in a given category or subcategory dictates whether § 112(d)(2)(A) or (B) should apply. That alternate approach is far more consistent with section 112(d) and Congress' plain intent. It is also well within EPA's discretion to adopt this more consistent approach. The word "sources" as used in the last clause of sections 112(d)(3)(A) and (B) to describe the size of the subcategory at issue does not specify whether it refers to "sources" for which data exist or the total number of sources in the subcategory. However, the word "sources" in the earlier facets of those sections clearly refers to the sources for which EPA has emissions information. Thus, it is reasonable to conclude that Congress intended the word "sources" to have a consistent meaning within these subsections and that the reference "30 or more sources" at the end of section 112(d)(3)(A) and "fewer than 30 sources" at the end of section 112(d)(3)(B) reasonably means sources for which

EPA has emissions information. That interpretation allows EPA to read the statute such that Congress' chosen line between new and existing source-setting methodology is not blurred.³⁴

However, this dilemma does not exist if EPA properly uses all available emissions information to estimate emissions for all sources in the subcategory. This approach ensures that the top-performing 12 percent of a category with more than 30 sources will never fall below the five-source minimum that Congress established. Indeed, Congress likely did not anticipate a scenario in which EPA would develop a MACT floor with emissions information from less than 50 percent of the sources in a subcategory of 30 or more.

[Footnote 34: *See, e.g., United Savings Ass'n of Tex. v. Timbers of Inwood Forest Assoc., Ltd.*, 484 U.S. 365 (1988) (rejecting a "reasonable" meaning of a statutory term and stating that "[s]tatutory construction ... is a holistic endeavor. A provision that may seem ambiguous in isolation is often clarified by the remainder of the statutory scheme- because the same terminology is used elsewhere in a context that makes its meaning clear . . . or because only one of the permissible meanings produces a substantive effect that is compatible with the rest of the law" (citations omitted)); *S. Cal. Edison Co. v. FERC*, 195 F.3d 17 (D.C. Cir. 1999) (striking down FERC's statutory interpretation that rendered statutory text meaningless in favor of an alternate interpretation without this effect, noting that "statutory words are ... designed to carry out the statutory purposes").]

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Douglas A. McWilliams

Commenter Affiliation: American Municipal Power

Document Control Number: EPA-HQ-OAR-2002-0058-3685-A2

Comment Excerpt Number: 30

Comment: The Sampling Data Used to Set the MACT Floors Does Not Reflect the True Operating Variability of the Sources at Issue. EPA is required to estimate the variability associated with all factors that impact a source's emissions, including process, operational, and non-technological variables, in setting MACT floors.³⁵ Any method used to estimate emissions rather than actually measure them "must allow a reasonable inference as to the performance of the top 12 percent of units," and EPA must show "why its methodology yields the required estimate."³⁶

EPA has acknowledged this responsibility and identified a number of factors that contribute to variability in emissions test data, including: (1) the emission test method, (2) the emission analytical method, (3) the design of the unit and the control device(s), (4) operating conditions of the facility and the control device(s), and (5) the composition and relative amounts of fuel constituents in the fuel or flue gases.³⁷ EPA is correct to incorporate variability into the MACT floor analysis in this rulemaking, but did not properly reflect the full range of variables potentially impacting emissions. Variability in boilers depends on a host of operating and load conditions. While EPA evaluated some of these variables, it did not evaluate a sufficient number to provide "an accurate picture of the relevant sources' actual performance."³⁸ For example, EPA does not have fuel quality data for all top performers.

[Footnote 35: *See Nat 'l Lime Ass 'n v. EPA*, 627 F.2d 416, 443 (D.C. Cir. 1980).]

[Footnote 36: *Cement Kiln Recycling Coalition v. EPA*, 255 F.3d 855, 862 (D.C. Cir. 2001) (emphasis in original) (citing *Sierra Club v. EPA*, 167 F.3d 658,663 (D.C. Cir. 1999)).]

[Footnote 37: *See Proposed National Emissions Standards for Hazardous Air Pollutants for Electric Utility Steam Generating Units*, 69 Fed. Reg. 4652, 4670 (Jan. 30, 2004).]

[Footnote 38: *Cement Kiln Recycling Coalition*, 255 F.3d at 862 (emphasis in original).]

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Douglas A. McWilliams

Commenter Affiliation: American Municipal Power

Document Control Number: EPA-HQ-OAR-2002-0058-3685-A2

Comment Excerpt Number: 32

Comment: EPA underestimates the true variability of the top performing sources. This results in a 99% upper prediction limit (UPL) that simply fails to account for all variables and fuel quality variability present in the top 12 percent best-performing units across all the subcategories and certainly across all regulated units. Municipal utilities would benefit from EPA revisiting its methodology and capturing more of the variability for coal-fired sources when it recalculates the MACT floors for the final rule.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Richard D. Garber

Commenter Affiliation: Boise Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3686-A2

Comment Excerpt Number: 5

Comment: EPA should use the flexibility authorized in the Clean Air Act to establish limits that meet regulatory requirements without being overly burdensome and costly. Boise's operations and products must compete in the global marketplace for market share. To the extent that the Boiler MACT regulations are overly burdensome and costly to implement, our company's competitiveness is adversely impacted compared to that of our global competitors.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

103A. MACT Floor Methodology: Statistical Approach (“Best of the Best”) [DENIED PETITIONER ISSUE]

Commenter Name: Kevin G. Desharnais, Attorney, Mayer Brown LLP

Commenter Affiliation: United States Sugar Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3496-A1

Comment Excerpt Number: 15

Comment: Despite the time that has elapsed since publication of the Proposed Rule, EPA still has not gathered a meaningful amount of new data for numerous categories of sources, and many emissions limits continue to be supported by only a handful of sources.

U.S. Sugar explained in its prior comments, which it incorporates by reference here, that if EPA cannot gather data on more than 30 sources--either because fewer than 30 sources exist in a category or because gathering more data would be unreasonable--the statute *requires* that MACT floor be set based on the top five sources for which the EPA has data. 42 U.S.C. § 7412(d)(3). EPA's decision to set the MACT floor according to the top 12 percent of sources, even in situations where it possesses data on only a handful of sources, results in a single boiler setting the emission limits for entire categories. That is flatly contrary to the language and intent of the CAA.

U.S. Sugar requests that EPA reconsider its decision to rely upon the best performing 12 percent of sources where EPA does not possess data on at least 30 sources. U.S. Sugar also requests that EPA reconsider its data set and solicit new data as companies begin sampling their emissions to comply with the rule. As more data becomes available, EPA should reevaluate the feasibility of its emissions limits and adjust the standards accordingly.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Sarah E. Amick

Commenter Affiliation: Rubber Manufacturers Association (RMA)

Document Control Number: EPA-HQ-OAR-2002-0058-3503-A1

Comment Excerpt Number: 9

Comment: If we were sure that the available data were statistically representative of the entire subcategory (such that calculating the MACT floor with fewer sources would result in approximately the same value as the MACT floor using data from the entire subcategory), then the lack of data likely would not significantly skew the results. However, the proposed rule and supporting documentation provide no assurance that where limited available data are available that they are representative of the entire source category. As a result, we believe that the lack of available data will produce MACT floors that are not reflective of the subcategory as a whole. While it is true that the statute allows EPA to determine the MACT floor based on sources "for which the Administrator has emissions information," this provision does not excuse EPA from using its resources and legal authority to obtain as much information as it reasonably can prior to setting MACT standards. In this case, EPA has had 20 years to gather the needed information. The fact that, at this point, data on only a small subset of sources in each subcategory is available represents an abdication of EPA's responsibility and renders the resulting standards arbitrary and capricious.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Sarah E. Amick
Commenter Affiliation: Rubber Manufacturers Association (RMA)
Document Control Number: EPA-HQ-OAR-2002-0058-3503-A1
Comment Excerpt Number: 11

Comment: The above table points out that EPA is using less than 5 sources to set the majority of the MACT floors for the light and heavy fuel subcategories. [See submittal for table] EPA has explained that it is using the top 12 percent of sources where there are more than 30 sources in a subcategory. EPA should use no fewer than 5 sources in setting the MACT floor for any source category – regardless of the number of sources in the category or subcategory. Congress clearly expected enough emissions information to be available for larger source categories to generally cause more than 5 sources to constitute the top 12%. It makes no sense for Congress to specify a minimum number of sources for source categories with few sources, but then to create a rule that would allow for standards to be set using data from fewer than 5 sources in larger source categories. Using no less than 5 sources would give effect to the clear intention of Congress.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Sarah E. Amick
Commenter Affiliation: Rubber Manufacturers Association (RMA)
Document Control Number: EPA-HQ-OAR-2002-0058-3503-A1
Comment Excerpt Number: 12

Comment: We note that the word “sources” as used in the last clause of §§ 112(d)(3)(A) and (B) is ambiguous and, therefore, susceptible to reasonable interpretation by the Agency. As EPA explains in the preamble, the word “sources” might be construed to refer to all sources in the given category or subcategory. However, the word “sources” in the first clause of §§ 112(d)(3)(A) and (B) clearly refers to the sources for which EPA has emissions information. Notably, the second use of the word “sources” in § 112(d)(3)(A) also clearly is a reference to sources for which EPA has emissions information. So, it is reasonable to conclude that Congress intended the word “sources” to have a consistent meaning for all purposes under these provisions. In other words, the reference “30 or more sources” at the end of § 112(d)(3)(A) and “fewer than 30 sources” at the end of § 112(d)(3)(B) reasonably should be construed as a reference to sources for which EPA has emissions information. This interpretation allows for EPA to naturally reconcile the application of §§ 112(d)(2)(A) and (B) such that the number of sources for which EPA has emissions information in a given category or subcategory dictates whether § 112(d)(2)(A) or (B) should apply.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Lorraine Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1
Comment Excerpt Number: 23

Comment: Many of the new source limits are set using one 3-run stack test. EPA could further consider variability by using the upper limit (UL) instead of the UPL statistical calculation, and using a 99.9 percent confidence level instead of a 99 percent confidence level, since sources will be required to meet the new source limits at all times.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 73

Comment: OTHER MACT FLOOR ISSUES

EPA is proposing a stringent set of emission limits that are not always based on the use of any technology. In many cases, boilers are achieving low emission rates not due to the use of any particular technology, but due to the mix of fuels being fired (which in many cases include fuels with pollutant contents below the limits of detection) or other unit specific characteristics that are not transferable to other sources. Facilities are limited in the fuels that their boilers can fire by design, cost, permits, and fuel availability. EPA should not set limits for hundreds of boilers based on data from a few boilers in which the specific mechanisms resulting in lower emissions are not fully understood and that are not available to all units in the subcategory.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 75

Comment: *EPA is Using a Biased, Unrepresentative Data Set*

Clean Air Act § 112(d) requires EPA to set a MACT floor for existing sources that is not less stringent than "the average emission limitation achieved by the best-performing 12 percent of the existing sources (for which the Administrator has emissions information)." *See* 42 U.S.C. § 7412(d); *Nat. Res. Def. Council v. EPA*, 489 F.3d 1250, 1254 (D.C. Cir. 2007). The top 12% "best performing" sources are known as "MACT floor units" or "units comprising the MACT floor."

During Phase I of EPA's data gathering effort (August 2008), EPA requested and received emissions data from over 2,000 sources across all of the subcategories for PM, CO, NO_x, and many HAPs. After sifting the data into fuel-based categories, EPA issued a second §114 request in June 2009 requiring additional testing. During this second phase of data gathering, EPA targeted only those sources the Agency knew it needed data from to set the MACT floor (e.g., the top performers) instead of obtaining a sampling of emissions data across the entire population

of boilers in a subcategory to assess the variability in performance of boilers in a particular subcategory. In this way, EPA artificially limited the pool of data from which it drew its top 12% "best performing" sources and biased the collection of emissions data. The data are not evenly distributed, but are clustered well below the mean, and since EPA has chosen to select the top 12 percent of boilers for which it has stack test data instead of the top 12 percent of boilers for which it has any emissions information, this has resulted in the proposed MACT floors being based effectively on the top 12 percent of the top 12 percent of boilers.

Even more troubling is the fact that in many cases, a large population of boilers is being represented by only a handful of data points. The table below presents information on the number of boilers in each subcategory, the number of boilers for which EPA believes it has data, and the number of boilers on which the MACT floor is based. The only data being used to calculate MACT floors are the data obtained during the ICR and subsequent facility submittals to the docket, even though EPA has available data from other sources (e.g., NEI and TRI data).

If it could be ascertained that the available data were statistically representative of the entire subcategory (such that calculating the MACT floor with 12 percent of the number sources for which EPA received site-specific data would result in approximately the same value as the MACT floor using data from 12 percent of the entire subcategory), then the lack of data likely would not significantly skew the results. However, the Reconsideration Proposal and supporting documentation provide no assurance that the limited available data from a fraction of the sources in a category or subcategory are representative of the entire source category or subcategory. As a result, ACC believes that the lack of available data has produced MACT floors that are not being set by the best performing sources in a category or subcategory and are not reflective of the category or subcategory as a whole.

In some cases, EPA has augmented available stack test data with calculated emission factors in order to increase the number of sources on which the MACT floor is based (e.g., liquid fired boilers for which fuel data or stack test data from an identical boiler at the site are available). EPA should expand this approach by obtaining emissions data from all boilers in a subcategory, whether by obtaining additional fuel data, additional stack test data, or estimating emissions for these boilers based on available emission factors. In fact, EPA has estimated emissions for all of the boilers being regulated under the MACT in order to quantify the expected emissions reductions of the Final Boiler Rule. Therefore, EPA should be using data from the top 12 percent of the total number of boilers in each subcategory in order to set limits, not 12 percent of the sources for which it has received stack test or fuel analysis data. EPA is using this approach in the CISWI rule.

The following tables [see submittal for tables] demonstrate the disparity between the amount of data currently being used to set standards and the actual percentage of boilers in each subcategory that are being represented by each floor (assumes EPA has properly subcategorized units). *EPA has not used 12 percent of the number of existing sources to set floors in any subcategory that has more 30 or more sources.*

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Lorraine Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1
Comment Excerpt Number: 77

Comment: *EPA Should Adjust its Procedures for Setting New Source Limits*

Some of the new source and existing source limits are the same (for example, the solid fuel HCl limit) because the 99 UPL for the new unit data is higher than the 99 UPL for the existing unit data. If the emissions data for the top performing unit exhibits more variability than the emissions data for the existing units then EPA cannot ignore this fact. It is arbitrary to choose the calculated existing unit limit as the standard that both types of units must meet. EPA should instead set both the existing and new unit standards at the calculated new unit UPL in order to adequately reflect variability and apply a defensible fuel variability factor to appropriately determine an achievable existing source emission limit recognizing the limitations of the floor determination process as indicated above.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: James Pew
Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity
Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1
Comment Excerpt Number: 13

Comment: As pointed out in the 2010 Comments, EPA incorrectly assumed that sources’ emission levels would vary to the full extent of the 99th percent upper prediction limit (UPL). That assumption was wrong because, as the agency is well aware, many of the sources in the top 12% use control technology or other methods to control their emissions. Because such measures limit emissions, the emission levels at such sources do not vary randomly. Further, as EPA is also well aware, source operators’ training and care in operating their sources and control equipment also limit variability in emissions. Moreover, because sources test their emissions under operating conditions designed to reflect the worst possible emission levels, their unadjusted test results already reflect unrealistically high emissions and there is no basis to assume that these sources’ emissions will get even worse – far less significantly worse – during further tests. For each of these reasons, sources’ actual emission levels are in no way reflected by the 99th percent UPL merely because such a level might be statistically possible. By using the 99th percent UPL, EPA adopts an approach to estimating emissions that ignores factors that affect emissions. Significantly, EPA itself acknowledged in the 2011 final rule "that the variability of emissions is not solely statistical, but also represents some operational variability that may occur between different tests at the same units (intra-unit variability) as well as different tests at different units (inter-unit variability) in the floor." 76 Fed. Reg. 15,608, 15,630/1-2 (March 21, 2011). Nowhere, however, has EPA explained why it nonetheless pretends that sources’ emissions do vary to the full 99th percent UPL.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 16

Comment: EPA invariably "rounded" the numbers generated by its UPL and fuel variability factors up. It rounded up values less than 100 to one significant figure, rounded up UPL values between 100 and 1,000 to two significant figures, and rounds up UPL values greater than or equal to 1,000 to three significant figures. 2010 Comments at 27. At proposal, EPA falsely claimed that its rounding approach had no significant effect on the floors. Confronted with record evidence of the falsity of that claim, the agency now argues that standards must be complied with at all times. That argument, however, does not alter the fact that EPA's rounded up numbers do not reflect the actual performance of any source and would not reflect sources' actual performance even if all the other floors in the agency's approach could be ignored. In any event, because the other aspects of EPA's approach grossly overstate sources' actual emission levels, rounding normally would not yield standards that were lower than sources' actual emissions; rather, it would merely yield standards that did not overstate their emissions so egregiously.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 17

Comment: EPA's professed concerns about compliance tests are misplaced. EPA has a policy of allowing sources to be deemed in compliance with an emission standard if their emission test result can be rounded down to the level of the standard under normal rounding principles. For example, a test result of 3.49×10^{-6} would be deemed in compliance with the standard of 3.0×10^{-6} . EPA's decision to round up is unlawful in itself. The Clean Air Act requires floors to reflect the emission levels achieved by the best sources not those emission levels rounded up to the nearest whole number. EPA's departure from normal rounding practices by always rounding up in setting floors – i.e., rounding up whether the fraction is above or below one half – exacerbates that unlawfulness and is arbitrary. And the agency's inconsistent approach to rounding for standard setting and compliance determinations is inconsistent, irrational, unexplained, and therefore arbitrary.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 23

Comment: EPA misrepresents the performance of the sources it has identified as the relevant best performers for the purposes of setting existing source floors. Specifically, EPA not only misrepresents each individual source's performance, but also adopts an existing source floor approach that does not yield an accurate estimate of the best performing twelve percent of sources in each subcategory for which the agency has emissions information and would not yield an accurate estimate even if the agency accurately represented the actual performance of the individual sources in these groups.

As explained in the 2010 Comments, EPA's floors do not reflect the "average" emission limitation achieved by the relevant best performing sources, but the 99% UPL for these sources. 2010 Comments at 24-26. Whatever else may be said of the EPA's 99th percentile UPL approach, the upper prediction limit of the emission level achieved by the best performing twelve percent of sources is not the "average" emission level achieved by those sources. Because Clean Air Act § 112(d)(3) unambiguously requires EPA to set floors reflecting the "average" emission level achieved by the best sources, setting floors that instead reflect a UPL for those sources is unlawful. By claiming that it can use the UPL for all sources in the top twelve percent, EPA misreads its authority to consider variability under the Clean Air Act and relevant caselaw. Although EPA may consider variability in estimating an individual source's actual performance over time, nothing in the Act or the caselaw even suggests that the agency may account for differences in performance between sources except as § 112(d)(3) provides, by averaging the emission levels achieved by the sources in the top twelve percent. Indeed, EPA errs by viewing the different emission levels achieved by different sources as "variability" at all. The different emission levels achieved by different sources are just differences in performance and provide no basis for applying statistical methods. Notably, EPA conceded at proposal that the objective of its statistical approach was to "estimate a MACT floor that is achievable by the average of the best performing sources if the best performing sources were able to replicate the compliance tests in our data base." 75 Fed. Reg. at 32019-32020 (emphasis added). The Clean Air Act requires EPA to set floors reflecting what the best sources actually achieved, not what the agency thinks is "achievable" – either for the best performing sources or any other group. Thus, EPA not only fails to propose floors reflecting the "average" emission level "achieved" by the relevant best sources, but admits that its goal was to set floors that would be "achievable" by those sources ninety-nine percent of the time. That stated goal is a result that the Clean Air Act does not permit. By attempting to rewrite the Clean Air Act to advance its own policy preferences – floors that reflect EPA's subjective notions about what is "achievable" ninety-nine percent of the time for all sources in the top twelve percent rather than the average emission level actually achieved by these sources, EPA acts unlawfully and frustrates Congress' intent in enacting § 112(d)(3).

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 24

Comment: EPA appears to have exacerbated the unlawfulness and arbitrariness of its floors by taking the 99% UPL for the group of alleged best performers even though it already applied the a

99% UPL to each individual source within the group. Specifically EPA used its UPL approach (and other means of inflating individual sources' performance described above and in the 2010 Comments) to assign to each individual source an emission level so high that even if the upward variability of that source's emission levels were not limited by control measures such as end-of-stack control measures, fuel selection, or operator care and control, that source would still achieve lower emission levels in 99% of all future tests. Because that approach clearly ensures that each individual source's performance cannot possibly be worse than the emission level EPA has assigned to it, the agency's decision to further inflate existing source floors by applying yet another 99% UPL to the entire group is egregiously unlawful and arbitrary. Such floors do not reflect the average performance of the best sources but, rather, the 99 % statistically worst possible performance within a group of sources each one of which is already unlawfully and arbitrarily assumed to perform at its 99% statistically worst possible level.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 25

Comment: EPA appears to have based some floors not on the top twelve percent of units for which it has emissions information but on the top five units. Revised MACT Floor Analysis (November 2011) at 5. The agency claims that it "identified the best performing 12 percent (or top 5 units) for each subcategory." *Id.* Although Clean Air Act § 112(d)(3) directs EPA to set floors based on the top five units for categories or subcategories with fewer than 30 sources, there are no "subcategories" within the industrial boilers category within the meaning of § 112. Specifically, although § 112(d) allows EPA to "distinguish among classes, types, and sizes of sources within a category or subcategory" in establishing emission standards, the agency does not create different "subcategories" merely by drawing such distinctions. Rather, EPA can create separate subcategories only by listing them under § 112(c). The groups of sources that EPA describes as "subcategories" are not actually "subcategories" at all, but merely groups of sources within the boilers category for which EPA believes it has authority to set different standards. Accordingly, EPA must base floors on the best performing twelve percent of sources for which it has emissions information for each such group regardless of whether they contain thirty or more sources.

Response: Section 112(d)(3) provides that EPA must establish MACT floors for existing sources based on the average of the best-performing twelve percent of sources "in the category or subcategory[.]" or the average of the best performing five sources "in the category or subcategory for categories or subcategories with fewer than 30 sources." The commenter does not allege that EPA has improperly based the MACT floors on the average of the best performing five sources for subcategories with 30 or more sources, but rather claims that EPA lacks authority to create subcategories for the boilers and process heater source category unless it expressly lists those subcategories under section 112(c). EPA disagrees with this interpretation of the Act. First, as noted above, section 112(d)(3)'s MACT floor provision specifically refers to the best twelve percent of sources (or best five sources) "in the category or subcategory[.]"

which recognizes EPA’s subcategorization authority and requires EPA to treat subcategories separately when establishing MACT floors for existing sources. Second, section 112(d)(1) states that EPA “may distinguish among classes, types, and sizes of sources within a category or subcategory in establishing [section 112(d)] standards[.]” (emphasis added) Thus, Congress envisioned that, when establishing MACT standards, EPA would evaluate the listed source category and determine whether establishing subcategories was appropriate, and then establish standards for each category or subcategory according to the provisions of section 112(d)(3). Nothing in these provisions suggests that Congress intended to require EPA to separately list each subcategory under section 112(c) before establishing MACT standards. Rather, the language of section 112(d)(1) referenced above indicates that Congress intended that EPA decide whether to exercise its subcategorization discretion at the time it established emissions standards for a listed source category.

This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 27

Comment: In many instances, EPA’s floor approach yields floors that are mathematically impossible, absurd, or both. For the majority of its standards, the result of EPA’s new source floor analysis was a number higher – *i.e.*, worse – than its existing floors. It is mathematically impossible for the emission level achieved by the single best performing source in a group to be worse than the average emission level achieved by the best performing twelve percent of sources in that same group. Rather than recognizing this reality and adopting a different floor approach that does not yield such absurd results, the agency blithely asserts that it can simply paper over the problem by setting its new source floors at the same level as its existing source floors. That is neither a solution nor a rational response to the problem. First, floors that purport to reflect the emission level achieved by the best performing 12 percent of sources for which EPA has emissions information do not purport to reflect the emission level achieved by the single best performing source and, for this reasons as well as those identified in the 2010 Comments, EPA’s new source floors are unlawful and arbitrary. Second, when a floor approach generates mathematically impossible results, it makes no sense to simply paper over the problem by just making up a different floor as the agency has done here. Rather, the agency needs to reevaluate its floor approach and come up with a different one that meets the agency’s obligation to set floors that actually reflect the emission level achieved by the relevant sources.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 28

Comment: Further, EPA’s statistical approach to variability yields numbers that are both impossibly low and impossibly high. First, if EPA were correct about the extent of the variability of many sources’ emissions, those sources would be capable of emission rates below zero. That is clearly impossible and yet, rather than recognizing that it has grossly overstated variability, EPA simply ignores the impossible downward variability and accepts the upward variability – which is no less impossible – as accurate. In other instances, EPA’s calculation of upward variability yields the impossible result of predicting that sources will emit more mercury than is contained in their fuel. Boilers cannot create mercury. Instead of recognizing this basic fact, however, EPA ignores it and continues to pretend that its floor approach is rational.

Overall, EPA’s floor approach leads to floors so high that few if any sources subject to any given standard will have to reduce their emissions. The agency’s games with statistics are, ultimately, just another attempt to avoid the Clean Air Act’s floor language and circumvent the D.C. Circuit decisions interpreting this language. Such evasion is not only unlawful but amounts to contempt for Congress and the courts.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 35

Comment: EPA is proposing a stringent set of emission limits that are, in many cases, not based on the use of any technology. In many cases, boilers are achieving low emission rates not due to use of any particular technology, but due to the mix of fuels being fired (which sometimes includes fuels with pollutant contents below the limits of detection) or other unit specific characteristics that are not transferable to other sources. Facilities are limited in the fuels that their boilers can fire by design, cost, permits, and fuel availability. EPA should not set limits for hundreds of boilers based on data from a few boilers in which the specific mechanisms resulting in lower emissions are not fully understood and that are not available to all units in the subcategory.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 36

Comment: The suite of limits should be achievable by at least 6 percent of existing boilers in each subcategory and the remaining boilers should be able to comply through their range of normal operating scenarios by applying known control equipment solutions. This expectation is not met for a broad range of units. Based on our review of the available data, less than 6 percent of units in the dry biomass stoker, biomass suspension burner, coal stoker, pulverized coal, and

all liquid subcategories can comply with the entire suite of applicable limits. This indicates to us that EPA has not adequately addressed the variability of emissions from units in these subcategories in selecting numerical limits.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 39

Comment: Some of the new source and existing source limits are the same (for example, the solid fuel HCl limit) because the 99 UPL for the new unit data is higher than the 99 UPL for the existing unit data. If the emissions data for the top performing unit exhibits more variability than the emissions data for the existing units, EPA cannot ignore this fact. It is arbitrary to choose the calculated existing unit limit as the standard that both types of units must meet. EPA should instead set both the existing and new unit standards at the new unit 99 UPL in order to adequately reflect variability and acknowledge the capabilities of the top performer to meet a standard.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 53

Comment: Clean Air Act § 112(d) requires EPA to set a MACT floor for existing sources that is not less stringent than "the average emission limitation achieved by the best-performing 12 percent of the existing sources (for which the Administrator has emissions information)." *See* 42 U.S.C. § 7412(d); *Nat. Res. Def. Council v. EPA*, 489 F.3d 1250, 1254 (D.C. Cir. 2007). The top 12% "best performing" sources are known as "MACT floor units" or "units comprising the MACT floor."

During Phase I of EPA's data gathering effort, it requested and received emissions data from over 2,000 sources across all of the subcategories for PM, CO, NOX, and many HAPs. After sifting the data into fuel-based categories, EPA issued a second section 114 request requiring additional testing. During this second phase, EPA impermissibly targeted only those sources from which the Agency knew it needed data to set the MACT floor (e.g., the top performers) instead of obtaining a sampling of emissions data across the entire population of boilers in a subcategory to assess the variability in performance of boilers in a particular subcategory. In this way, EPA artificially limited the pool of data from which it drew its top 12% "best performing" sources and biased

the collection of emissions data. The data are not evenly distributed, but are clustered well below the mean, and since EPA has chosen to select the top 12 percent of boilers for which it has stack test data instead of the top 12 percent of boilers for which it has any emissions information, this has resulted in the proposed MACT floors being based effectively on the top 12 percent of the top 12 percent of boilers. This is patently at odds with section 112(d).

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 54

Comment: In many cases, a large population of boilers is being represented by only a handful of data points. The table below presents information on the number of boilers in each subcategory, the number of boilers for which EPA believes it has data, and the number of boilers on which the MACT floor is based. The only data being used to calculate MACT floors are the data obtained during the ICR and subsequent facility submittals to the docket, even though EPA has available data from other sources (e.g., NEI and TRI data).

If the available data were statistically representative of the entire subcategory (such that calculating the MACT floor with fewer sources would result in approximately the same value as the MACT floor using data from the entire subcategory), then the lack of data likely would not significantly skew the results. However, the proposed rule and supporting documentation provide no assurance that where limited available data are available that they are representative of the entire source category. As a result, we believe that the lack of available data will produce MACT floors that are not reflective of the subcategory as a whole.

While it is true that the statute allows EPA to determine the MACT floor based on sources "for which the Administrator has emissions information," this provision does not excuse EPA from using its resources and legal authority to obtain as much information as it reasonably can prior to setting MACT standards. In this case, EPA has had 20 years to gather the needed information. The fact that, at this point, data on only a small subset of sources in each subcategory are available represents an abdication of EPA’s responsibility and renders the resulting standards arbitrary and capricious.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 55

Comment: In some cases, EPA has augmented available stack test data with calculated emission factors in order to increase the number of sources on which the MACT floor is based

(e.g., liquid fired boilers for which fuel data or stack test data from an identical boiler at the site are available). EPA should expand this approach by obtaining emissions data from all boilers in a subcategory, whether by obtaining additional fuel data, additional stack test data, or estimating emissions for these boilers based on available emission factors. In fact, EPA has estimated emissions for all of the boilers being regulated under the MACT in order to quantify the expected emissions reductions. Therefore, EPA should be using the top 12 percent of the total number of boilers in each subcategory in order to set limits. EPA is using this approach in the CISWI rule.

The following tables demonstrate the amount of data currently being used to set standards and the actual percentage of boilers in each subcategory that are being represented by each floor (assumes EPA has properly subcategorized units). EPA has not used 12 percent of the number of existing sources to set floors in any subcategory that has more than 30 units. [See submittal for tables.]

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 56

Comment: EPA is using less than 5 sources to set MACT floors. EPA has explained that it is using the top 12 percent of sources where there are more than 30 sources in a subcategory. EPA should use no fewer than 5 sources in setting the MACT floor for any source category – regardless of the number of sources in the category or subcategory. Congress clearly expected enough emissions information to be available for larger source categories to generally cause more than 5 sources to constitute the top 12%. It is not plausible that Congress specified a minimum number of sources for source categories with few sources, but then created a rule that would allow for standards to be set using data from fewer than 5 sources in larger source categories. Using no less than 5 sources would give effect to the clear intention of Congress.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 57

Comment: We note that the word "sources" as used in the last clause of §§ 112(d)(3)(A) and (B) is ambiguous and, therefore, susceptible to reasonable interpretation by the Agency. As EPA explains in the preamble, the word "sources" might be construed to refer to all sources in the given category or subcategory. However, the word "sources" in the first clause of §§ 112(d)(3)(A) and (B) clearly refers to the sources for which EPA has emissions information. Notably, the second use of the word "sources" in § 112(d)(3)(A) also clearly is a reference to sources for which EPA has emissions information. So, it is reasonable to conclude that Congress

intended the word "sources" to have a consistent meaning for all purposes under these provisions. In other words, the reference "30 or more sources" at the end of § 112(d)(3)(A) and "fewer than 30 sources" at the end of § 112(d)(3)(B) reasonably should be construed as a reference to sources for which EPA has emissions information. This interpretation allows for EPA to naturally reconcile the application of §§ 112(d)(2)(A) and (B) such that the number of sources for which EPA has emissions information in a given category or subcategory dictates whether § 112(d)(2)(A) or (B) should apply.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Mary Sullivan Douglas

Commenter Affiliation: National Association of Clean Air Agencies (NACAA)

Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1

Comment Excerpt Number: 2

Comment: In light of the significant errors related to variability, NACAA strongly recommends that EPA revisit each of its MACT floor calculations, especially where the proposed floor is so lenient that a large majority of existing sources already meet the limit. We believe EPA has sufficient information available to EPA to correct the errors in its current proposal and issue a final rule on reconsideration in the next few months.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Mary Sullivan Douglas

Commenter Affiliation: National Association of Clean Air Agencies (NACAA)

Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1

Comment Excerpt Number: 4

Comment: EPA's methodology results in a situation where, in a majority of EPA's proposed subcategories, the calculated new source MACT floor (based on the best performing unit) is higher (less stringent) than that for existing sources (based on the average of the top 12 percent of units in the subcategory). Common sense and basic arithmetic provide that the rate of emissions of the "best" unit (i.e., the lowest emitter in the group) must be less than the average of that unit and the emission rates of a group whose emissions are higher. At a minimum, the procedure adopted by EPA must achieve this result.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Mary Sullivan Douglas

Commenter Affiliation: National Association of Clean Air Agencies (NACAA)

Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1

Comment Excerpt Number: 7

Comment: In calculating the average of the selected units, EPA assumes that the performance of a selected unit is defined by all test results⁶ available for that unit. [Footnote] (6) EPA includes all test results of “best performers” in its calculation of the MACT floor for each subcategory. This effectively over weights the contribution of sources that have been tested multiple times compared to those that may have been tested only once.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Mary Sullivan Douglas

Commenter Affiliation: National Association of Clean Air Agencies (NACAA)

Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1

Comment Excerpt Number: 10

Comment: In the development of the 2004 rule for this sector, EPA determined the base performance level of the median unit in the top 12 percent and then applied a variability factor that was calculated on the average of the variance in performance for all units with similar pollution technologies. The U.S. Court of Appeals determined that EPA’s method for identifying the base performance level was inappropriate, but did not opine on the method for determining the variability factor.⁸ In developing the 2010 final rule, EPA attempted to calculate the anticipated variation in performance of each of the units in its “best performing” group on an individual unit or subcategory basis. Rather than simply determining the variance in performance, EPA chose to calculate the UPL of the best performing units, that is, the emission level that each unit in the top 12 percent could be expected to meet at a 99th percentile confidence level. EPA’s procedure also errs by attempting to determine the emission level that the bottom half of the top 12 percent will meet 99 percent of the time. However, EPA should not expect these units to meet the MACT floor limit since nominally half of the top 12 percent do not meet the average and therefore are not complying units.⁹ The development of a compliance margin should be limited to an evaluation of the variability of the top 6 percent performing units under the compliance conditions imposed by the regulation.

[Footnotes]

(8) It did agree that EPA could apply a variability factor to take into account expected variation in performance of such units.

(9) Those units in the top 12 percent, but with emission levels greater than the average of the top 12 percent (i.e., the 6th through 12th percent best performers), do not “comply.”

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Mary Sullivan Douglas

Commenter Affiliation: National Association of Clean Air Agencies (NACAA)

Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1

Comment Excerpt Number: 12

Comment: Pooled variance is a method for estimating variance given several different samples taken in different circumstances where the mean may vary between samples but the true variance (or precision) is assumed to remain the same. Under EPA’s revised UPL procedure, fuel analyses results are disaggregated from emission test results and further disaggregated by the number of unique sources. As a result, the method is highly sensitive to the number of tests and the number of units that are tested. However, in some subcategories the majority of the test and fuel analysis results were BDL and the detection limits for the emission test results are several times lower than those for the fuel analyses. EPA’s pooled variance process generates high levels of variability, based largely on differences in the degree of precision of the measuring process and EPA’s treatment of BDL data (where the results are known to be less than the BDL). This leads to unreasonable results where the sample size is relatively small. In addition to generating unrealistic results for a broad array of new source subcategories, EPA’s proposed new statistical approach also appears to lead to results for PM and CO that are not consistent with the in-use performance of units in a number of other subcategories with limited data.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Mary Sullivan Douglas

Commenter Affiliation: National Association of Clean Air Agencies (NACAA)

Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1

Comment Excerpt Number: 18

Comment: EPA has recommended the use of the 99th percentile UPL of pre-regulation testing and argued that its use is justified because the agency adopted the same approach in the medical waste incinerator MACT rule. This rationale does not explain why EPA believes the 99th percentile UPL is appropriate and not the 50th,¹⁵ 90th or, for that matter the 99.99th percentile.¹⁶ The decision matters because with each increase in the “guaranteed” compliance margin, the standard increases, and there comes a point where the compliance margin is so great that sources can merely accept the risk of a failed compliance test rather than reduce emissions. If a source fails a compliance test it will ordinarily be afforded the opportunity for a retest and only if a source has a confirmed deficiency in its control equipment will a modification be ordered. We are unaware of any situation where a source that is willing to make such modifications as are necessary to meet an applicable limit has ever been ordered to permanently cease operation on the basis of a single failed stack test. In contrast, where an excessive compliance margin is provided emission standards can be ineffective.

[Footnotes]

(15) Civil enforcement of environmental standards is based on a “preponderance of the evidence,” which merely requires that a violation be more likely than not (51st percentile).

(16) Some in industry have argued that the levels should be set so that there is no significant probability that a facility would fail a compliance test at any point in its useful life.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Mary Sullivan Douglas

Commenter Affiliation: National Association of Clean Air Agencies (NACAA)

Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1

Comment Excerpt Number: 19

Comment: The degree to which emission tests results can vary are not truly random, but are constrained by the laws of physics and chemistry and, in many instances, the performance of pollution control devices. EPA's statistical analyses of the data show that, if the data were randomly distributed, there would be a substantial number of instances where emission rates are less than zero. We know that this is not possible and so the data are "skewed" to the right. One method used by statisticians to adjust for this form of distribution is to assume what is known as a log-normal distribution. [See submittal for Figure 1.] With the assumption of a log-normal distribution, one then evaluates the distribution of the logarithm of the number rather than the number itself. EPA has employed this method in a number of instances. One feature of log-normal distributions is that they have "tails" that become very long as the variance increases. That is, the difference between the mean and the value that represents the 90th percentile probability is much greater where one assumes a log-normal distribution than otherwise. However, we know that the emission rate of specific pollutants, such as mercury, ("Hg"), can never be larger than the amount of Hg in the fuel and that emission rates are also influenced by the operational characteristics of installed pollution control devices. Yet, EPA's calculations routinely predict results that are inconsistent with these facts. They also lead to results, cited above, where the performance of the best performing unit is calculated to be worse than the average of the top 12 percent and where the calculated performance of the best units approximates the demonstrated performance of the worst units. These examples illustrate the point that in order to properly determine whether a particular statistical method is appropriate for a data set, one must determine whether the results of the method employed make sense. We submit that EPA's decision to use the 99th percentile leads to unrealistically large calculated variations in performance of the best performing units, especially where the distribution is assumed to be log-normal and especially where the sample size is small so that relatively large variances are computed.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Mary Sullivan Douglas

Commenter Affiliation: National Association of Clean Air Agencies (NACAA)

Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1

Comment Excerpt Number: 20

Comment: There are additional facts to help guide EPA's determination of a standard compliance margin to be applied to all subcategories - the compliance obligations and testing conditions that are imposed by the standard. An equitable balance is struck when the same conditions used to establish the compliance margin are thereafter used to set the compliance obligation (and vice versa). If a source is required to be regularly tested under conditions that represent the 99th percentile "worst-case" conditions, then a 99th percentile compliance margin might well be appropriate. Additionally, a larger compliance margin is ordinarily appropriate for

standards with short averaging periods and continuous emission monitors ("CEMs") than for standards that have long averaging periods or where compliance is determined by scheduled stack tests conducted by the source.¹⁷

[Footnote]

(17) We do not intend to suggest that there is widespread cheating during compliance testing. Our point is that the source has substantial prior notice of such tests and is in control of the operating conditions during the test.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Mary Sullivan Douglas

Commenter Affiliation: National Association of Clean Air Agencies (NACAA)

Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1

Comment Excerpt Number: 22

Comment: While EPA may have used the 99th percentile UPL in one recent New Source Performance Standard ("NSPS"), in other NSPS rulemakings, such as the mercury limits under the utility NSPS 40 CFR Part 60, Subpart Da,²¹ it has employed a 90th percentile statistical test (t-test) coupled with the same test for the fuel-sampling compliance demonstration.

[Footnote]

21 See, Memorandum from Robert Wayland, OAQPS, to William Maxwell, OAQPS, "Revised new source performance standard (NSPS) statistical analysis for mercury emissions" (sic), May 31, 2006.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Mary Sullivan Douglas

Commenter Affiliation: National Association of Clean Air Agencies (NACAA)

Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1

Comment Excerpt Number: 27

Comment: In the absence of sufficient data to make determinations of the variability of individual units and subcategories with limited data, EPA should develop a reasonable compliance margin to apply to the best-complying sources. The underlying issues are sufficiently complex that, in the absence of truly comprehensive data, no single analysis will likely prove to be dispositive. For this reason we recommend that EPA perform a series of analyses and examine the central tendency of the results of those analyses. From these results EPA can establish one or more default variability factors to apply where the limited number of test results affects the calculation of variability in a given subcategory. One such group of analyses, but by no means the only approach that could prove useful, is to start with the most comprehensive data set to determine a broad "default" variability factor and examine more specific data sets to determine whether a more limited variability factor can be assigned based on the data available.²⁷ Such an

approach could proceed as follows: Commence the process by identifying all units that may reasonably be found to be in the top 12 percent. This might include the top 25 – 33 percent of units based on their mean test result and all units whose mean test emissions are within an order of magnitude of the best performing unit.

Calculate the nominal “performance” of each unit; by summing the mean and one standard deviation²⁸ of the unit specific data. Average the performance of the top performing 12 percent, understanding that this is likely an overestimate, based on the low number of test runs for most units. Since this approach is likely to overestimate the variability to some degree, the results of the first assessment should be considered an upper bound of potential MACT floors, EPA should then look to see if the variability of the broad group is less than that calculated above. Using the pool of “best performers” identified above, normalize the emission test results for all sources for which EPA has data, including those not in the top 12 percent and determine the average variability in the performance for the broad group. EPA could accomplish this by dividing the variance for each unit by the mean of the data for that unit and average the results, not the UPL. It has been argued that sources in the top 12 percent have less variability than the population at large and so this variance should be considered to represent an upper bound of a permissible variance.

Repeat the above-described analyses for the three basic subgroups – solid, liquid and gas. This then would form a second set of possible default variability factors for the subgroups for which sufficient data are available. Since there are more tests available for the entire liquid-fired set of units, it may prove possible to develop a separate variability factor for liquid-fired units, which, while likely larger than that for the best performing units, is more accurate than that based on limited data for the best performing units. Repeat the above-described analyses using data for the top best-performing, 50 percent, 25 percent, 12 percent and 6 percent of the basic subgroups. Employ these results if the average variance is less than that for the larger group or if it can be established that the calculated increase in variance is due to differences in performance and not the consequence of the reduced sample size. Iteration in this fashion should identify a point where the reduction in sample size outweighs the improvements normally expected from better performing units. For purposes of determining the arithmetic average, results reported at a detection limit should be employed as recorded, however, for purposes of determining variance such results should be excluded as they artificially reduce the variance. For purposes of determining the arithmetic average of the best performing top 12 percent, all test results should be employed to identify the best performers, not the best single result. This will increase the arithmetic average, but is a more reasonable estimate of the performance of units with multiple tests than the lowest single result currently employed by EPA.

Once the variance of the data has been determined, it should be applied to the arithmetic average of the top 12 percent, not to any unit in the data set. Consistent with most of the enforcement expectations, we recommend that it be applied at the 90th percentile level. For those subcategories where the data are sufficiently robust, a variability factor specific to the subcategory may be applied; for all others the applicable MACT floor would be the arithmetic average of the data for the subcategory, as adjusted by the applicable default variability factor.

Where a source or group of sources wishes to maintain that a different variability factor should apply, those parties should be responsible for providing sufficient data to develop a factor that is not dominated by the paucity of data. Additionally, EPA could determine the “normalized”

variance for each unit where more than a certain number of tests (perhaps 10) are available and average those values. EPA should examine the performance of similar units in the electric generating unit sector and other sectors and review relevant BACT and LAER determinations. EPA should also examine the overall distribution of the data set at issue to determine a reasonable variability factor. Where there are a large number of units with similar emission levels, a large variability adjustment should not be applied. Where EPA determines that a source category's emissions are highly variable over a short period (e.g., CO), EPA should consider longer averaging periods, such as 30-day rolling averages, that reflect and accommodate this form of variability, while still preserving the environmental benefits the CAA contemplates. However, under no circumstances should 30-day CEM-based limits be higher than the corresponding reference method (three- hour) limit.

[Footnotes]

(27) We have not conducted these sorts of analyses and have no way of anticipating their results.

(28) It may be more appropriate to use Student's t-test at a similar level of confidence.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Mary Sullivan Douglas

Commenter Affiliation: National Association of Clean Air Agencies (NACAA)

Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1

Comment Excerpt Number: 35

Comment: EPA's approach to "rounding" introduces an additional inappropriate bias to the calculation of MACT floors and should be revised to reflect technically correct rounding procedures and the requirements of the statute. In the calculation of the MACT floor, such as the application of calculated UPLs, EPA "rounded" the interim values and in each such instance rounded the values up. In most engineering calculations, rounding protocols provide for rounding down as well as up. Rounding ordinarily includes truncating the number of significant digits that are employed in a calculation and occurs at the end of the calculation process. EPA justifies its decision to only round up by asserting that to do otherwise would deprive sources of the "variability" cushion they were otherwise entitled to. Again, this argument ignores the public interest in reducing emissions of hazardous air pollutants, as well as normal engineering protocols. It would also seem to be contrary to written EPA policy concerning rounding for NSPS compliance purposes.³⁶ This policy, which has not been revised to our knowledge, adopts ASTM standard rounding protocols – carry at least five significant digits throughout all intermediate calculations and employ ASTM Procedure E 380 (round down if less than 5; round up if greater than 5) for the final calculation. Where a MACT floor would otherwise be calculated at 2.27, it would seem that "rounding" a final standard to 3.00 would be technically unjustifiable and would not comply with the requirement of section 112 that the MACT standard be not less stringent than the average of the top 12 percent.

[Footnote]

(36) See, “Memorandum: Performance Test Calculation Guidelines”, William Laxton, OAQPS, and John Seitz, OAQPS.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Mary Sullivan Douglas

Commenter Affiliation: National Association of Clean Air Agencies (NACAA)

Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1

Comment Excerpt Number: 55

Comment: NACAA believes that EPA’s proposal to establish emission limits to two significant digits is a step in the right direction, but recommends that those limits be set to three significant digits. No reason has been advanced by EPA for not doing so.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 20

Comment: The methodologies EPA has relied on to establish emission limits have resulted in some new sources and existing sources having the same standards. For example, the HCl limit is the same for solid fuel new sources and existing sources. This likely occurred because the 99 UPL for the new unit data is higher than the 99 UPL for the existing unit data and EPA choose the calculated existing unit limit as the standard that both types of units must meet. EPA’s approach is arbitrary. EPA should instead set both the existing and new unit standards at the new unit 99 UPL in order to adequately reflect variability.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 21

Comment: EPA set many of the new source limits using one 3-run stack test. EPA should consider variability and use the UL instead of the UPL statistical calculation. This approach is appropriate and justified because sources will be required to meet the new source limits at all times. EPA should also consider fuel variability data for all units setting new source floors and that variability should be included in the calculated emission limits. As CIBO indicated in its earlier comments and Petition for Reconsideration of the Final Boiler MACT Rule, variability is important in setting achievable emission limits.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Douglas A. McWilliams

Commenter Affiliation: American Municipal Power

Document Control Number: EPA-HQ-OAR-2002-0058-3685-A2

Comment Excerpt Number: 28

Comment: EPA Impermissibly Ignored Non-Stack Emission Data and Used Inadequate and Biased Data to Set the MACT Floors Section 112(d) of the Clean Air Act requires EPA to set MACT floors for existing sources that are not less stringent than "the average emission limitation achieved by the best-performing 12 percent of the existing sources (for which the Administrator has emissions information)." 42 U.S.C. § 7412(d); *Nat. Res. Def. Council v. EPA*, 489 F.3d 1250, 1254 (D.C. Cir. 2007). The top 12 percent "best performing" sources become the MACT floor units. To identify these units, EPA must collect "emissions information" from units that are included in the source category. During Phase I of EPA's data gathering effort, it requested and received emissions data from over 2,000 sources across all of the subcategories for PM, CO, NOx, and many HAPs. After sifting the data into fuel-based categories, EPA issued a second section 114 request requiring additional testing. During this second phase, EPA impermissibly targeted only those sources the Agency had identified as the top performers based on Phase I, instead of obtaining a random sampling of emissions data across the entire population of boilers in a subcategory to assess the variability in performance of boilers in a particular subcategory. In this way, EPA artificially limited the pool of data from which it drew its top 12 percent and biased the data collection. The data is not evenly distributed, but is clustered well below the mean. EPA further limited the pool of data from which it established the MACT floors by considering only units with stack test data in identifying the top 12 percent. EPA ignored other "emissions information" that it is required to consider pursuant to section 112(d). This combination of missteps resulted in EPA proposing MACT floors that are based on the top 12 percent of the top 12 percent of units in each subcategory in violation of section 112(d).

This led to EPA considering data from only a portion of each subcategory in setting the MACT floors. For the existing solid fuel subcategory, for example, EPA considered HCl data from only 33 percent of the sources in the subcategory and Hg data from only 29 percent. This led to MACT Floors being set by 4 percent and 3.5 percent of the source category, respectively. The figures are even worse for CO. For existing coal-fired units, EPA considered emissions data from only 11 percent of stoker units and 19 percent of pulverized coal units, with the MACT floor limits being determined by only 1.5 and 1.1 percent of the respective categories. The number of sources used to establish PM limits for coal-fired units was higher, but still inadequate at 47 percent for stokers and 56 percent for pulverizers.

If it was certain that the available data were statistically representative of the entire subcategory (such that calculating the MACT floor with fewer sources would result in approximately the same value as the MACT floor using data from the entire subcategory), then the lack of data likely would not significantly skew the results. However, the Proposed Rule and supporting documentation provide no assurance that the limited available data are representative of the entire source category. As a result, there is no way to know if the available data are producing a

MACT floor that is not reflective of the subcategory as a whole. That lack of data raises serious doubts regarding the validity of the MACT floor determinations and resulting emissions limitations.

EPA's failure to use adequate data is inexcusable. EPA has been working on the Boiler MACT standards for more than 15 years, and had ample time to gather and evaluate sufficient emissions data. Furthermore, the Clean Air Act explicitly instructs EPA to base its MACT floors on all units for which EPA has "emissions information ." This is an unambiguous statutory directive, and EPA may not artificially limit its review to testing data. Emissions information extends beyond stack test data to include volume and types of fuels and the emissions controls used by the vast majority of industrial boilers and process heaters in use today. EPA has developed emissions factors for various types of units based on this information and published them in AP-42 and other compilations. Sources are encouraged to rely on these emission factors to estimate emissions in the absence of actual test data. EPA too, then, should have used these emissions factors to estimate emissions for those units without emission testing data. This is "emissions information" that is readily available to EPA and should be included in selecting the group of sources that represent the top 12 percent of performers.

EPA's failure to gather sufficient data and evaluate all emissions data available in each subcategory resulted in many units - including small municipal utilities without significant test data - being ignored in setting the MACT floors. EPA has (or could reasonably obtain) emissions information from virtually all coal-fired sources using AP-42 emissions factors, and is obligated to consider the data from all of these units in establishing the MACT floor.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 40

Comment: Many of the new source limits are set using one 3-run stack test. EPA could further consider variability by using the UL instead of the UPL statistical calculation and using a 99.9 percent confidence level instead of a 99 percent confidence level, since sources will be required to meet the new source limits at all times. In addition, fuel variability data should be collected for all units setting new source floors and factored into the calculated emission limits. Industrial boilers operate over a variety of conditions and fire a variety of fuels, so adequate consideration of variability is important in setting achievable emission limits. EPA continues to use a pollutant-by-pollutant approach instead of a source-based approach to setting new unit limits, so maximum consideration of variability is imperative.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Mary Sullivan Douglas

Commenter Affiliation: National Association of Clean Air Agencies (NACAA)

Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1

Comment Excerpt Number: 59

Comment: EPA has proposed MACT floors for CO emissions from three subcategories that are either at, or very close to, the sole test result for the subcategory, effectively providing no allowance for in-use variation in performance. No reason is offered for EPA's decision and we assume that some correction will be made.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Sarah E. Amick

Commenter Affiliation: Rubber Manufacturers Association (RMA)

Document Control Number: EPA-HQ-OAR-2002-0058-3503-A1

Comment Excerpt Number: 7

Comment: The suite of limits should be achievable by at least 6 percent of existing boilers in each subcategory and the remaining boilers should be able to comply through their range of normal operating scenarios by applying known control equipment solutions. This expectation is not met for a broad range of units. Based on our review of the available data, less than 6 percent of units in all liquid subcategories can comply with the entire suite of applicable limits. This indicates to us that EPA has not adequately addressed the variability of emissions from units in these subcategories.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Sarah E. Amick

Commenter Affiliation: Rubber Manufacturers Association (RMA)

Document Control Number: EPA-HQ-OAR-2002-0058-3503-A1

Comment Excerpt Number: 8

Comment: Clean Air Act § 112(d) requires EPA to set a MACT floor for existing sources that are not less stringent than "the average emission limitation achieved by the best-performing 12 percent of the existing sources (for which the Administrator has emissions information)." *See* 42 U.S.C. § 7412(d); *Nat. Res. Def. Council v. EPA*, 489 F.3d 1250, 1254 (D.C. Cir. 2007). The top 12% "best performing" sources are known as "MACT floor units" or "units comprising the MACT floor."

During Phase I of EPA's data gathering effort, it requested and received emissions data from over 2,000 sources across all of the subcategories for PM, CO, NO_x, and many HAPs. After sifting the data into fuel-based categories, EPA issued a second section 114 request requiring additional testing. During this second phase, EPA impermissibly targeted only those sources the Agency knew it needed data from to set the MACT floor (e.g., the top performers) instead of obtaining a sampling of emissions data across the entire population of boilers in a subcategory to assess the variability in performance of boilers in a particular subcategory. In this way, EPA artificially limited the pool of data from which it drew its top 12% "best performing" sources and

biased the collection of emissions data. The data are not evenly distributed, but are clustered well below the mean, and since EPA has chosen to select the top 12 percent of boilers for which it has stack test data instead of the top 12 percent of boilers for which it has any emissions information, this has resulted in the proposed MACT floors being based effectively on the top 12 percent of the top 12 percent of boilers. This is patently at odds with section 112(d). In many cases, a large population of boilers is being represented by only a handful of data points. The table below presents information on the number of boilers in the liquid fuel subcategory, the number of boilers for which EPA believes it has data, and the number of boilers on which the MACT floor is based. The only data being used to calculate MACT floors are the data obtained during the ICR and subsequent facility submittals to the docket, even though EPA has available data from other sources (e.g., NEI and TRI data).

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Sarah E. Amick

Commenter Affiliation: Rubber Manufacturers Association (RMA)

Document Control Number: EPA-HQ-OAR-2002-0058-3503-A1

Comment Excerpt Number: 10

Comment: In some cases, EPA has augmented available stack test data with calculated emission factors in order to increase the number of sources on which the MACT floor is based (e.g., liquid fired boilers for which fuel data or stack test data from an identical boiler at the site are available). EPA should expand this approach by obtaining emissions data from all boilers in the liquid subcategories, whether by obtaining additional fuel data, additional stack test data, or estimating emissions for these boilers based on available emission factors. In fact, EPA has estimated emissions for all of the boilers being regulated under the MACT in order to quantify the expected emissions reductions. Therefore, EPA should be using the top 12 percent of the total number of boilers in each subcategory in order to set limits. EPA is using this approach in the CISWI rule. The following table demonstrates the amount of data currently being used to set standards and the actual percentage of boilers in light and heavy liquid fuel subcategories that are being represented by each floor (assumes EPA has properly subcategorized units). [See submittal for table] EPA has not used 12 percent of the number of existing sources to set floors in the light or heavy fuel subcategories.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Mary Sullivan Douglas

Commenter Affiliation: National Association of Clean Air Agencies (NACAA)

Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1

Comment Excerpt Number: 5

Comment: EPA has studied its approved reference testing methods for years and has amassed significant information about the performance of those methods. Based on this body of knowledge, EPA reports that, where the result of a test is near the detection level applied, most of its test procedures are accurate to within +/- 50 percent; at other times EPA asserts that these

tests are accurate to within +/- 15 percent. Monitoring devices, such as CO monitors, must meet stringent requirements for drift and must be calibrated to within 2 percent of the full scale value of the expected emission level of the unit. The paired testing data and other data in the record of this case show that, especially at the better performing sources, the variability in Hg and other specific pollutants is quite low. Similarly, years of testing of pollution control devices found in this sector, such as PM controls (fabric filters and electrostatic precipitators (“ESP”)), show highly consistent performance. Thus far, EPA has not factored any of these facts into its determination of the performance of the best performing units.

In order to evaluate whether EPA’s procedure for calculating variability is appropriate, one first has to examine what “variability” EPA is calculating and whether it is relevant under sections 112 or 129. EPA’s procedure involved determining the 99th percentile UPL of the difference in performance between all test runs for all units in the top 12 percent. This calculation improperly combines two factors: (1) the inter-unit difference between the “best performers” and “the best of the best performers” and (2) the expected variability in performance for each of the best-performing units. EPA does not have the resources to evaluate each of these situations in detail to determine whether the difference represented inherent variability in performance of the unit or is a consequence of factors (such as fuel composition or specific hardware design) that are within the control of the source, and so it simply, and incorrectly, assumes that each of the units within the top 12 percent is identical and that all of the difference in performance is a “variability” in performance that is essentially random and therefore susceptible to statistical analysis. This can be addressed by normalizing the data so that one only examines the variability in performance. Replicate compliance method testing of the best performing units over a period of years and varying operating conditions would likely be the best method for determining which units are among the best performing units and for assessing the variability of the performance of such units. However, EPA does not have such information and development of this information is infeasible at this time. Moreover, EPA does not have sufficient data of any sort to make an accurate assessment of the variability of either individual units or subcategories with relatively limited data. As discussed earlier, the problem is readily apparent for new sources, where EPA’s attempts to determine the variability in the performance of the “best” unit based on a single reference test clearly produce an incorrect result. This problem also exists in a large number of existing source subcategories where EPA has insufficient test data to apply its method. EPA has acknowledged this problem and attempted to partially respond to it by using its “beyond the floor” MACT authority to raise the new source MACT limit to the level of the existing source MACT floor in 24 subcategories. While directionally correct, we believe it is unlikely that this will be found to be sufficient, since common sense and basic arithmetic demonstrate that the result is still wrong – the performance of the “best” individual unit cannot be the same as the average of the larger group. Moreover, EPA does not make a similar adjustment to existing source MACT floors that are also based on limited data. NACAA recommends that EPA examine a number of additional options for assigning a variability factor, including a return to the philosophy underlying its 2004 determination of variability of performance. We provide more detailed recommendations later in this section. EPA compounds the error associated with attempting to employ its statistical procedures to extremely limited data sets by applying a series of multipliers and alternate tests of variability. In most, but not all instances, EPA selects the test that leads to the least stringent MACT floor determination. Moreover, the basis for several key decisions respecting data management (discussed below) is not well supported. The lack of a consistent, reasoned basis for EPA’s choices creates a risk that the rule will be overturned and in

some instances, the resulting floor calculation will be substantially different if other, equally reasonable, factors are used in developing the final determination. We discuss a number of these issues in detail below, but the impact of EPA's new statistical approach in categories with relatively small numbers of tests is clearly illustrated by the Hg limit EPA calculated for liquid-fired boilers. While these factors affect all of EPA's MACT floor calculations, they are most apparent in the calculations for new sources, which, under EPA's methodology, always involve single units with limited testing. The following discussion sets out our best understanding of the relative impacts of several EPA choices on the overall effectiveness of the resulting MACT floor for other subcategories. We have included herein and attached as Appendix 1 a series of charts setting out EPA's test data as provided as appendices to its MACT floor memo for each unit, along with EPA's proposed limit for the applicable subcategory. These charts provide a basis for the assessment of the effectiveness of the proposed limit. EPA's appendices included only the "lowest test result" for a given unit rather than all test results. In most instances, the difference in effectiveness is minimal, as most sources were only tested once, so the "lowest test result" is also the highest test result. Where a significant number of units were subjected to more than one test, we have also produced a chart including all test results for the top 12 percent to assist in gauging the effectiveness of the proposed limit. We encourage EPA to produce similar charts, including all test results, for all units for the rules it ultimately adopts.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Bill Lane

Commenter Affiliation: American Home Furnishings Alliance (AHFA)

Document Control Number: EPA-HQ-OAR-2002-0058-3676-A2

Comment Excerpt Number: 4

Comment: The Clean Air Act (CAA) MACT provisions clearly state that the MACT floor is to be calculated as "the average emission limitation achieved by the best performing 5 sources" for categories and subcategories with fewer than 30 sources (CAA Section 112(d)(3)). In the proposed MACT floor calculation, instead of following the plain language of the CAA, EPA limited the best performing sources for use in the floor calculation to the number that could comprise a minimum of 12% of the subcategory, or to one unit if there were 8 or fewer units in the subcategory. For a small subcategory with a widely varying range of emission rates such as the kiln-dried biomass subcategory, the floor calculation does not recognize the variability inherent among all boilers in the group and results in an emission limitation that is not achievable for nearly all boilers in the subcategory. We believe that establishing the floor based on one or two units would be arbitrary and capricious. AHFA urges EPA to implement an approach that considers the emissions variability inherent in this subcategory, and to 1) calculate the mathematical average of the top 5 performers with data, and 2) apply a 99.9% upper prediction limit (UPL) to account for variability within the subcategory. Without this type of common sense approach to the MACT floor calculation, we anticipate that our members will be faced with the prospect of switching from carbon-neutral biomass fuels to non-renewable fossil fuels, or shutting down facilities and shifting to overseas production.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 68

Comment: NCASI is providing additional comments on the limitations associated with using the empirical rule on all variability ratios within a specific fuel subcategory, to identify and remove outliers. The following are worth mentioning:

- The assumption that the entire sample of variability ratios is normally distributed is false.
- Further, the outliers identified using this assumption can neither be discarded by graphical observation of the data including the suspected outlier(s) nor can they be discarded based on the requirement that the remaining data without the suspected outlier(s) be normally distributed.
- Additionally, the standard deviation criteria (eliminating outlier values that do not lie within three standard deviations of the mean of all of the computed ratios in the fuel subcategory) may not appropriately account for "intra-unit" variability in fuel pollutant concentrations. In such cases, the empirical rule may have to be applied on a unit-specific basis to reconfirm outliers. More details on this issue are submitted in separate comments by NCASI.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

103C. MACT Floor Methodology: Ranking by Average [DENIED PETITIONER ISSUE]

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 12

Comment: EPA ranked sources by their single lowest emission tests. For example, a source that with three tests reflecting emissions of 10 units, 100 units and 100 units respectively would be ranked better than a source with three tests reflecting emissions of 15 units, 15 units and 15 units respectively. For purposes of setting floors (as opposed to identifying the alleged best performers), however, EPA did not continue to measure individual sources' performance by their lowest emission test. Instead, EPA applied statistical factors allegedly to estimate each source's 99th percentile worst performance based on all their emission test results. Under this approach, EPA would conclude that the performance of the source with three tests of 10 units, 100 units and 100 units in the example above is substantially worse than the source with emission tests of 15 units, 15 units and 15 units respectively even though the agency would have identified the first source as better for the purpose of ranking sources and selecting the best performers. Not only does the first source have two tests that are much worse than any test results from the second source but the variation between the test results for the first source would lead EPA to claim that its adjusted performance is actually much worse even than its worst test. Because

EPA's floors do not reflect the performance of the relevant best sources as EPA itself measures performance, they contravene § 112(d)(3), which provides that new standards must, at a minimum, reflect the emission level achieved by the single best performing source and that existing source standards must, at a minimum, reflect the average emission level achieved by the average of the best performing twelve percent of the sources for which the agency has emissions information. Further, to the extent EPA claims these floors reflect the performance of the best sources, its claim is arbitrary and capricious both because the record shows that other sources are better performing and because EPA has not provided a rational explanation for choosing one method to rank sources' performance and another to measure it.

As a practical matter, EPA's inconsistent approach to identifying the best sources and measuring these sources' performance substantially decreases the protectiveness of its standards. By using different methods to identify sources as best performing on the one hand and to estimate these sources' performance on the other, EPA selects sources with relatively high variation as the "best" – even though these sources would not be labeled best if the agency ranked them under its own approach to measuring performance. Next, EPA uses that variability of performance in the sources it picked as best – sources that necessarily have higher variability in performance than do the sources that would be "best" under the agency's own approach to measuring performance – to inflate the floors. If EPA used a consistent approach to identifying the best sources and to estimating these sources' performance, the standards would be far more protective. If EPA selected as best the sources with the single lowest emission test and then – consistent with that approach – also measured sources' performance based on their single lowest emissions test, its standards would be far more protective. Likewise, if EPA identified the best sources based on its statistical analysis of all their emissions tests and – consistent with that approach – measured their performance the same way, its standards would be far more protective. Only by changing its measurement approach part way through the floor setting process does the agency arrive at floors that so greatly exceed the actual performance of the relevant best sources.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Mary Sullivan Douglas

Commenter Affiliation: National Association of Clean Air Agencies (NACAA)

Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1

Comment Excerpt Number: 9

Comment: NACAA believes that EPA should use either the best test result for both purposes or use the best average of all test results for both purposes. This use of inconsistent definitions of performance has resulted in at least one MACT floor that is higher than it should be, as units with better average performance over all tests were excluded in favor of other units with a lower individual test result but higher overall emissions. We also believe that use of the average of all test results for an individual unit is an appropriate measure of the performance of that unit, provided that the subsequent analysis of variability does not then treat that average as a single test result. One way to address this issue may be to use the average of all test results to identify the best performing units in the calculation of the average of the top 12 percent, but then include all test results of the "best performers" in the determination of the potential variability of that average.⁷ The identification of the "best performers" should take place after all of the variability

adjustments have been made to the universe of “candidate best performers.” In this way the MACT floor would not be artificially increased by the use of data from sources that are ultimately not the best performers within a subcategory.

[Footnote]

(7) This is not the same as using the 99th percentile UPL of the individual runs as a factor to multiply the average.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

103D. MACT Floor Methodology: Pollutant-by-Pollutant Approach [DENIED PETITIONER ISSUE]

Commenter Name: Kevin G. Desharnais, Attorney, Mayer Brown LLP

Commenter Affiliation: United States Sugar Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3496-A1

Comment Excerpt Number: 14

Comment: EPA continues to utilize a pollutant-by-pollutant approach in establishing its MACT floors in the Reconsideration Proposal, and does not address U.S. Sugar's objections to this methodology. U.S. Sugar reiterates the arguments it made in its comments to the Proposed Rule and incorporates them by reference herein. In the Final Rule, EPA also offered several additional justifications for its approach. U.S. Sugar requested reconsideration on this issue, but the Reconsideration Proposal fails to address the concerns we raised.

EPA has misinterpreted and misapplied section 112(d)(3) of the CAA. Under that subsection's plain terms, EPA must set the MACT floor at "the average emission limitation achieved by the best performing 12 percent of the existing sources" or the "best performing five sources," depending on the number of sources in the subcategory. 42 U.S.C. § 7412(d)(3)(A)-(B).¹ EPA has some flexibility in how it selects the "best performing" sources and determines their "average." See *Sierra Club v. EPA*, 167 F.3d 658, 661 (D.C. Cir. 1999) (the phrase "average emission limitation achieved by the best performing 12 percent of units" "on its own says nothing about how the performance of the best units is to be calculated"). Nevertheless, EPA's discretion is bounded. Most critically, EPA may *not* set the MACT floor at a level that an "average" of "the best performing 12 percent" does not "achieve[]." [*d.* This means that for any MACT floor, it must be possible to take 12 percent of a subcategory's boilers, average those boilers' emissions, and have that number meet the MACT floor. If this is not possible, then the MACT floor is necessarily unreasonable. And a MACT floor is patently unreasonable if *no* boiler in a subcategory achieves the floor's standard.

This reading, compelled by the statute's clear text, fully comports with Congress's purpose in enacting subsection (d)(3). Subsection (d)(3) merely sets *ajloor* at a level "achieved in practice," not a standard beyond every source's reach. 42 U.S.C. § 7412(d)(3); see *Sierra Club v. EPA*, 479 F.3d 875, 884 (D.C. Cir. 2007) (Williams, 1, concurring) (statute "embodies an assumption that standards based on achievability will be more stringent than ones based merely on past

achievement"). Section II2(d)(3) makes this purpose obvious by repeatedly stressing the word "achieved." 42 U.S.C. § 7412(d)(3)(A)-(B) (requiring EPA to determine "the average emission limitation *achieved* by the best performing 12 percent of the existing sources" or "the average emission limitation *achieved* by the best performing 5 sources") (emphases added). In accord with this clear intent, the D.C. Circuit has held that "EPA may not deviate from section 7412(d)(3)'s requirement that floors reflect what the best performers actually achieve." *Cement Kiln Recycling Coal. v. EPA*, 255 F.3d 855,861 (D.C. Cir. 2001) (per curiam); see also *id.* at 857 (remanding "[b]ecause the standards fail to reflect the emissions achieved in practice by the best-performing sources as required by the Clean Air Act"). For more onerous restriction, Congress enacted subsection (d)(2). See *Sierra Club v. EPA*, 353 F.3d 976,980 (D.C. Cir. 2004) (Roberts, 1) (EPA may impose restrictions beyond MACT floor only "if the Administrator determines them to be achievable after 'taking into consideration the cost ... and any non-air quality health and environmental impacts and energy requirements'" (quoting 42 U.S.C. § 7412(d)(2)). But for the purpose of determining the MACT floor, "past achievement" is key. *EPA*, 479 F.3d at 884.

EPA's proposed rule violates the statute's clear language and Congress's unambiguous intent because it sets MACT floors at levels far beyond what the average of the "best performing 12 percent of existing boilers" have achieved in practice. 42 U.S.C. § 7412(d)(3)(A). The flaws in the proposed rule stem directly from EPA's erroneous decision to make separate MACT rankings "[f]or *each* pollutant" within each subcategory. 75 Fed. Reg. 32,019 (emphasis added). Rather than selecting the "best performing" 12 percent of boilers *across* the source subcategory for all regulated pollutants, the proposed rule creates five distinct categories of best performers and sets *one* subcategory-wide MACT floor that incorporates the five independent standards. Under this approach, it makes no difference whether the proposed MACT floor is achieved by the average of the subcategory's "best performing 12 percent." 42 U.S.C. § 7412(d)(3)(A)-(B). Indeed, it is almost certain that the average of the best performing 12 percent of sources will lie outside of the MACT floor. That is manifestly contrary to Congress's intent.

EPA's interpretation of the statute will lead to absurdities. If EPA were establishing standards for one pollutant alone, there would be no problem; EPA's proposed MACT floor necessarily would be achieved by the average of best performing 12 percent of each subcategory's boilers. But problems emerge once a second pollutant is introduced. Unless the best 12 percent of boilers with respect to the first pollutant are exactly the same as the best 12 percent with respect to the second pollutant, then EPA's methodology necessarily results in a MACT floor that is not achieved by a subset of] 2 percent of the subcategory's boilers. Worse yet, the top 12 percent at controlling for the first pollutant might be entirely different from the top 12 percent at controlling for the second pollutant; in such a case, EPA will propose a MACT floor that *no* boiler in the subcategory has achieved.

Problems continue to pile on with the introduction of each new regulated pollutant, as each new pollutant essentially means that fewer boilers will achieve the new MACT floor. EPA's current decision to regulate only five chemicals-PM, mercury, HCl, CO, and D/F masks this problem to some extent. If EPA separately regulated each of the pollutants listed in 42 U.S.C. § 7412(b)(1), this would all but ensure that no boiler in any subcategory would achieve EPA's proposed MACT floor.

These problems are not merely theoretical. EPA's method does not control for the fact that boilers in each subcategory use different control technologies that emphasize certain pollutants at

the expense of others. No one technology succeeds in eliminating all pollutants from air emissions. The best performer under each regulated pollutant will be heavily influenced by the choice of control technologies. This variation again causes each MACT floor to be set at a level that is not achieved by an average of any 12 percent of boilers. Moreover, because EPA has not controlled for control technologies, its unreasonably stringent MACT floors may require sources to install every control technology. Such a result is both ludicrous and impossible.

Congress clearly did not intend for these absurdities when it required MACT floors to be set at a level "that is achieved in practice." 42 U.S.C. § 7412(d)(3). However EPA defines "average" or "best," there must be a way to take the "average" of the emissions from the "best" 12 percent of a subcategory's boilers and have that number meet the MACT floor.

The increased number of subcategories in the Reconsideration Proposal addresses part of the problem, since it ties the standards more closely to the unit regulated and avoids the application of standards established based on units with vastly different emissions characteristics. Nevertheless, increased use of sub categorization does not fully solve the problem. As long as the top 12 percent of boilers with respect to one regulated pollutant is not exactly the same as the top 12 percent of boilers for *every other* regulated pollutant, then EPA inevitably will propose MACT floors that are not achieved by an average of 12 percent of each subcategory's boilers. In order to address this flaw, EPA must completely revise its interpretation of section 112(d)(3) and its methodology for setting MACT floors. Only through such an approach will MACT floors accord with congressional intent and the statute's unambiguous language. Simply put, EPA should rescind its decision to use five separate and independent MACT floors within each subcategory of sources. EPA should instead adopt a method that results in MACT floors already achieved by an average of a 12-percent subset of each subcategories' existing boilers.

In the Final Rule, EPA defended its pollutant-by-pollutant approach by claiming Section 112(d)(3) is ambiguous and its methodology is a reasonable interpretation. EPA is mistaken in both assertions. There is no indication in the statutory language that Congress intended the MACT floor be set pollutant by pollutant. Rather, a plain reading of the text reveals Congress intended the MACT floor be set at a level actually achieved by the average of the best 12 percent of sources . As EPA noted in the Final Rule, Section 112(d)(3) emphasizes that the floor must be based on what "sources" "achieve[] in practice." A "source" means an actual boiler, not a hypothetical boiler that incorporates the optimal qualities of each boiler design and control technology. Indeed, evaluating what a hypothetical boiler achieves "in practice" is inherently contradictory. Because EPA's pollutant-by-pollutant approach would set the MACT floor at levels not actually achieved in practice, it is inconsistent with a straightforward reading of the statute. See *Chevron v. NRDC*, 467 U.S. 837 (1984).

EPA's critiques of U.S. Sugar's interpretation are not persuasive. EPA suggests that under U.S. Sugar's reading, there is a possibility the MACT floor could be satisfied by sources with "mediocre or no control." 76 Fed. Reg. at 15622. But Section 112(d)(3) requires the floor be based upon actual, in-practice achievement, not aspirational technologies. EPA has no legal basis for setting the MACT floor at a level not achieved in practice.

U.S. Sugar urges EPA to reconsider its pollutant-by-pollutant approach and to solicit comments on alternative means of identifying the best sources in each subcategory.

[Footnote]

(1) For the sake of simplicity, we will assume that section 112(d)(3)(A) applies. The analysis under section 112(d)(3)(B) is no different.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: David A. Buff, Golder Associates Inc.

Commenter Affiliation: Florida Sugar Industry (FSI)

Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1

Comment Excerpt Number: 29

Comment: The FSI still objects to EPA’s use of a pollutant-by-pollutant approach to setting emission limits. The FSI believes that this approach leads to emission limits that may not be achievable by any one boiler (i.e., would require a "super boiler"). FSI realizes that determining the top 12 percent of boilers for which EPA has emissions data is more difficult when based on overall emissions. However, EPA should ensure that all of the sources in the top 12 percent of a subcategory (i.e., all of the boilers used to establish the MACT floor) can comply with all of the emission limits in the final Boiler MACT Rule for that subcategory.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: James Johnson

Commenter Affiliation: United States Beet Sugar Association (USBSA)

Document Control Number: EPA-HQ-OAR-2002-0058-3508-A1

Comment Excerpt Number: 6

Comment: In the reconsideration of the major source Boiler Rule, EPA has reconsidered several of the MACT floor limits. However, EPA retained the HAP-by-HAP approach of regulating each HAP separately, without regard to the interplay between pollutants and pollution-control equipment that can lower efficiencies and make it more difficult to meet the prescribed standards. A HAP-by-HAP approach— using a pollutant-by-pollutant analysis that looks at the best performing sources for each HAP and sets the floor based on those sources— creates challenges for regulated entities looking at the overall pollutant levels of their facilities. Because a HAP-by-HAP approach looks at the pollutants piecemeal, it does not represent what an actual source can achieve over time. Setting the standard this way makes it exceedingly difficult for regulated entities working in good faith to improve efficiencies enough to meet the standards and doing so comes only at enormous cost. In addition, such an approach does not conform to section 112 of the CAA because this section of the Act speaks to regulating pollutants reflecting the performance of “sources,” not individual pollutants seen in the abstract. As the D.C. Circuit has found, “EPA may not deviate from section 7412(d)(3)’s requirement that floors reflect what the best performers actually achieve.” Therefore, when setting the MACT floor, EPA should use a rubric of the best controlled sources, not a HAP-by-HAP approach. The use of a HAP-by-HAP approach and the resulting stringent standards will cause significant hardship for sugarbeet processing facilities that are major sources because it is extremely

difficult to meet all the prescribed standards at the same boiler. The USBSA urges EPA to reconsider such an approach given its adverse economic impact on seasonal, agricultural industries such as sugarbeet processors.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 25

Comment: EPA continues to use a pollutant-by-pollutant approach instead of a source-based approach to setting new unit limits, so maximum consideration of variability is imperative.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 74

Comment: The suite of limits should be achievable by at least 6 percent of existing boilers in each subcategory and the remaining boilers should be able to comply through their range of normal operating scenarios by applying known control equipment solutions. This expectation is not met for a broad range of units. Based on our review of the available data, less than 6 percent of units in the dry biomass stoker, biomass suspension burner, coal stoker, pulverized coal, and all liquid subcategories can comply with the entire suite of applicable limits. This indicates to us that EPA has not adequately addressed the variability of emissions from units in these subcategories.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Alicia Meads

Commenter Affiliation: National Association of Manufacturers (NAM)

Document Control Number: EPA-HQ-OAR-2002-0058-3515-A1

Comment Excerpt Number: 16

Comment: The EPA ignored the record evidence of the performance of actual "sources" when establishing the suite of emissions limits. Instead, for each subcategory, the EPA set individual limits for each HAP that reflect the best performing source only for that individual HAP. The EPA then combined the HAP limits into a suite of emissions standards for each subcategory. This methodology results in a combined set of standards reflecting purely hypothetical boilers that have never actually been achieved by any single, real world source, and possibly never will. Creating hypothetical "best performing" units that demand compliance with emission standards

not achieved by any actual source in a subcategory (let alone the necessary 12% of sources for a true floor) is arbitrary and capricious and violates the EPA's statutory obligation to establish limits that are based on actual the performance of "sources."

The proposed MACT standards for industrial boilers and process heaters are based on pollutant-by-pollutant analyses that rely on a different set of best performing sources for each separate HAP standard. *See, e.g.*, 76 Fed. Reg. at 15,621-23. In other words, the EPA "cherry picked" the best data in setting each standard, without regard for the sources from which the data came. This approach violates the language of § 112, which is focused on the performance of "sources," and produces arbitrary and capricious standards.

The statute unambiguously directs the EPA to set standards based on the overall performance of "sources."⁸ Sections 112(d)(1), (2), and (3) specify that emissions standards must be established based on the performance of "sources" "in practice" for the category or subcategory and that the EPA's discretion in setting standards for such units is limited to distinguishing among classes, types, and sizes of sources. In particular, Section 112(d)(3) emphasizes that the EPA must focus on what emissions reductions are achievable "in practice" for a "source," using the word "source" no fewer than nine times.

These provisions make clear that standards must be based on actual sources, and cannot be the product of pollutant-by-pollutant parsing which results in a set of composite standards that do not necessarily reflect the overall performance of any actual source. Congress provided express limits on the EPA's authority to parse units and sources for purposes of setting standards under § 112 and that express authority *does not* allow the EPA to "distinguish" units and sources by individual pollutant as is proposed in this rule. *Sierra Club v. EPA*, 551 F.3d 1019, 1028 (D.C. Cir. 2008) (noting statutory limitations on EPA's authority to distinguish sources).

Further, the EPA has calculated its proposed MACT floors solely on the basis of emission data. The EPA utterly ignored the plain mandate of the Clean Air Act by entirely neglecting to determine whether there was emission control equipment in use in each subcategory that could actually achieve those inordinately strict emission limits, a critical and necessary analysis required by the Clean Air Act.

The EPA's focus on individual HAPs has resulted in a failure to recognize the critical interplay between emissions controls and emissions of other pollutants. For example, the NAM is concerned that the controls necessary to meet the stringent emissions limitations for CO will result in increased energy usage, with the concomitant increase in emissions of NO_x and other pollutants. Further, the EPA failed to account for this interrelationship in its economic analysis.

[Footnote 8: In the proposed CISWI rule, EPA similarly failed to follow the statutory mandate under Section 129 to examine the performance of "units." For the reasons discussed above, the CISWI standards must be based on actual sources ("units"), and cannot be the product of pollutant-by-pollutant parsing.]

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Roger Martella
Commenter Affiliation: National Alliance of Forest Owners (NAFO)
Document Control Number: EPA-HQ-OAR-2002-0058-3519-A1
Comment Excerpt Number: 11

Comment: We urge EPA to focus on emissions standards that can actually be achieved in practice by considering all relevant pollutant emissions together rather than adopting a pollutant-by-pollutant approach that ignores trade-offs between emission control technologies and produces standards that cannot currently be met by any biomass boilers. EPA establishes the MACT floor for each source category by calculating the numerical average of the emissions from the best performing (lowest emitting) 12 percent of sources. By adopting a pollutant-by-pollutant approach, EPA selects different sources as the best performing 12 percent for each pollutant and ignores the trade-offs that inevitably occur when some emissions are minimized at the expense of others. When all of the MACT standards are evaluated together, they do not reflect the actual emissions of the best performing sources.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Dean C. DeLorey
Commenter Affiliation: The Amalgamated Sugar Company LLC (TASCO)
Document Control Number: EPA-HQ-OAR-2002-0058-3522-A1
Comment Excerpt Number: 4

Comment: The reconsidered emissions limits for each constituent (i.e., PM, HCl, mercury, CO and dioxin/furans) remain unreasonable and impractical⁵. EPA has proposed limits based on limited stack data for individual HAP's without considering combined HAP's associated with a specific emissions control technology for each subcategory. This approach is not practical and results in the most stringent Boiler MACT emissions standards. This approach potentially results in the most costly emissions control scenario and capital expenditures for boilers subject to these standards. As discussed above, this conservative approach is not justifiable since there is no documentation that industrial boiler HAPs result in any measurable air quality impacts. It is requested that the emissions standards be recalculated based upon combined HAPs emissions test results for each emission source category.

[Footnote]

(5) Table 1 (pg 80601)

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Allison Watkins, Baker Botts
Commenter Affiliation: Class of '85 Regulatory Response Group
Document Control Number: EPA-HQ-OAR-2002-0058-3608-A1
Comment Excerpt Number: 14

Comment: EPA has established MACT standards in the Major Source Rule using a methodology that is inconsistent with the text of the CAA because it results in MACT standards that are not representative of the HAP emission limits being achieved by existing sources. The Class of '85 urges EPA to revise the standards so that they reflect the actual, overall performance of existing sources.³⁰

EPA developed the MACT floors based on the best performing sources for *each* pollutant, without regard to the overall performance of those units. EPA's attempts to justify its selection of this methodology are unpersuasive. EPA has argued that a "whole source" approach "'guts the standards' by including worse performers in the averaging process, whereas EPA's interpretation promotes the evident Congressional objective of having the floor reflect the average performance of best performing sources."³¹ EPA's reasoning ignores the plain language of the Act, which requires the Agency to set a MACT floor for existing sources that is based on "the average emission limitation achieved by the *best-performing* 12 percent of the *existing* sources."³² The use of the terms "best-performing" and "existing" clearly indicate that the sources used to set the MACT floor must be real, not theoretical or hypothetical, sources.³³ Indeed, § 112(d)(3) states that the MACT floor for new units shall not be less stringent than the emission control that is "*achieved in practice* by the best controlled similar source."³⁴ The phrase "achieved in practice" can only mean that Congress intended actual sources, performing under normal operating conditions, to be the benchmark for establishing the MACT floors.

The language of § 112(d) does not in any way suggest that MACT floors should be based on the best-performing sources for each individual HAP.³⁵ Instead, the focus is on the emission limits that the best performing existing sources can actually achieve for *all* pollutants collectively.³⁶ If Congress had intended for EPA to establish MACT floor levels by considering the achievable emission limits of individual HAPs, it could have worded § 112(d)(3) to refer to the best-performing sources "for each pollutant" or "for each group of pollutants."³⁷ It is clear from the plain text of the CAA that "EPA has a statutory duty to promulgate *achievable* standards."³⁸ Moreover, pollutant-by-pollutant MACT standards are inconsistent with the legislative history of § 112(d). As the Senate Report on the 1990 Amendments made clear, Congress required "the selection of emissions limitations which have been *achieved in practice* (rather than those which are merely theoretical) by sources of a similar type or character."³⁹ Congress' focus on overall performance in the 1990 CAA Amendments is consistent with its abandonment of individual pollutant standards and the adoption of the technology-based multipollutant approach for regulating toxics under the Clean Water Act.⁴⁰ Congress understood that if one source can achieve a high degree of control for one pollutant, but not for another, there is no justification for including it in the set of sources from which the floor is calculated.⁴¹ EPA's methodology for establishing the MACT standards is inconsistent with the text of the CAA. The Group urges EPA to revise its methodology to reflect the overall performance of existing units.

[Footnote 30: EPA's pollutant-by-pollutant methodology has been challenged in the D.C. Circuit but the court has not yet ruled on the issue of whether the methodology comports with the language of the CAA. *See, e.g., Medical Waste Institute and Energy Recovery Council v. EPA*, 645 F.3d 420 (D.C. Cir. 2011) ("MWIERC"); *Portland Cement Assn. v. EPA*, 665 F.3d 177 (D.C. Cir. 2011). To date, the court has avoided ruling on the validity of the pollutant-by-pollutant methodology and has, instead, disposed of the issue on procedural grounds. *MWIERC*, 645 F.3d at 427; *Portland Cement*, 665 F.3d at 189.]

[Footnote 31: 76 Fed. Reg. at 15622.]

[Footnote 32: *Natural Resources Defense Council v. EPA*, 489 F.3d 1250, 1254 (D.C. Cir. 2007) (emphasis added).]

[Footnote 33: *See* 42 U.S.C. § 7412(d).]

[Footnote 34: 42 U.S.C. § 7412(d)(3) (emphasis added).]

[Footnote 35: *See* 42 U.S.C. § 7412(d).]

[Footnote 36: *Id.*]

[Footnote 37: *See Bluewater Network v. EPA*, 3701 F.3d 1, 18 (D.C. Cir. 2004) (rejecting EPA's interpretation of § 213(a)(2) of the CAA as running counter to the plain language of the statute, reasoning that "[h]ad Congress intended the meaning and result which EPA urges, it would have said so more clearly"); *Chevron U.S.A., Inc. v. Nat. Res. Def. Council*, 467 U.S. 837, 842-43 (1984) (holding that if Congress has spoken directly to the disputed issue of statutory construction, "that is the end of the matter; for the court, as well as the agency, must give effect to the unambiguously expressed intent of Congress").]

[Footnote 38: *Nat'l Lime Ass'n v. EPA*, 627 F.2d 416, 443 (D.C. Cir. 1980) (emphasis added).]

[Footnote 39: *See* S. Rep. No. 228, 101st Cong., 1st Sess. 169 (1989).]

[Footnote 40: *See id.* at 133-34.]

[Footnote 41: *See, e.g., Tanners' Council of America v. Train*, 540 F.2d 1188, 1193 (4th Cir. 1976) (deeming Clean Water Act effluent limitations guidelines not achievable where plants in EPA's database were "capable of meeting the limitations for some, but not all, of the pollutant parameters").]

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Randal G. Oswald

Commenter Affiliation: Integrys Energy Group

Document Control Number: EPA-HQ-OAR-2002-0058-3659-A2

Comment Excerpt Number: 13

Comment: EPA has established MACT standards in the Major Source Rule using a methodology that is inconsistent with the text of the CAA because it results in MACT standards that are not representative of the HAP emission limits being achieved by existing sources. Integrys urges EPA to revise the standards so that they reflect the actual, overall performance of existing sources.²⁶

EPA developed the MACT floors based on the best performing sources for *each* pollutant, without regard to the overall performance of those units. EPA's attempts to justify its selection of this methodology are unpersuasive. EPA has argued that a "whole source" approach "guts the standards" by including worse performers in the averaging process, whereas EPA's interpretation

promotes the evident Congressional objective of having the floor reflect the average performance of best performing sources."²⁷ EPA's reasoning ignores the plain language of the Act, which requires the Agency to set a MACT floor for existing sources that is based on "the average emission limitation achieved by the *best-performing* 12 percent of the *existing* sources."²⁸ The use of the terms "best-performing" and "existing" clearly indicate that the sources used to set the MACT floor must be real, not theoretical or hypothetical, sources.²⁹ Indeed, §112(d)(3) states that the MACT floor for new units shall not be less stringent than the emission control that is "*achieved in practice* by the best controlled similar source."³⁰ The phrase "achieved in practice" can only mean that Congress intended actual sources, performing under normal operating conditions, to be the benchmark for establishing the MACT floors.

The language of §112(d) does not in any way suggest that MACT floors should be based on the best-performing sources for each individual HAP.³¹ Instead, the focus is on the emission limits that the best performing existing sources can actually achieve for *all* pollutants collectively.³² If Congress had intended for EPA to establish MACT floor levels by considering the achievable emission limits of individual HAPs, it could have worded §112(d)(3) to refer to the best-performing sources "for each pollutant" or "for each group of pollutants."³³ It is clear from the plain text of the CAA that "EPA has a statutory duty to promulgate *achievable* standards."³⁴ Moreover, pollutant-by-pollutant MACT standards are inconsistent with the legislative history of §112(d). As the Senate Report on the 1990 Amendments made clear, Congress required "the selection of emissions limitations which have been *achieved in practice* (rather than those which are merely theoretical) by sources of a similar type or character."³⁵ Congress' focus on overall performance in the 1990 CAA Amendments is consistent with its abandonment of individual pollutant standards and the adoption of the technology-based multi-pollutant approach for regulating toxics under the Clean Water Act.³⁶ Congress understood that if one source can achieve a high degree of control for one pollutant, but not for another, there is no justification for including it in the set of sources from which the floor is calculated.³⁷

EPA's methodology for establishing the MACT standards is inconsistent with the text of the CAA. Integrys urges EPA to revise its methodology to reflect the overall performance of existing units.

[Footnotes]

(26) EPA's pollutant-by-pollutant methodology has been challenged in the D.C. Circuit but the court has not yet ruled on the issue of whether the methodology comports with the language of the CAA. *See, e.g., Medical Waste Institute and Energy Recovery Council v. EPA*, 645 F.3d 420 (D.C. Cir. 2011) ("MWIERC"); *Portland Cement Assn. v. EPA*, 665 F.3d 177 (D.C. Cir. 2011). To date, the court has avoided ruling on the validity of the pollutant-by-pollutant methodology and has, instead, disposed of the issue on procedural grounds. *MWIERC*, 645 F.3d at 427; *Portland Cement*, 665 F.3d at 189.

(27) 76 Fed. Reg. at 15622.

(28) *Natural Resources Defense Council v. EPA*, 489 F.3d 1250, 1254 (D.C. Cir. 2007) (emphasis added).

(29) *See* 42 U.S.C. § 7412(d).

(30) 42 U.S.C. § 7412(d)(3) (emphasis added).

(31) *See* 42 U.S.C. § 7412(d).

(32) *See* 42 U.S.C. § 7412(d). (33) *See Bluewater Network v. EPA*, 3701 F.3d 1, 18 (D.C. Cir. 2004) (rejecting EPA's interpretation of § 213(a)(2) of the CAA as running counter to the plain language of the statute, reasoning that "[h]ad Congress intended the meaning and result which EPA urges, it would have said so more clearly"); *Chevron U.S.A., Inc. v. Nat. Res. Def. Council*, 467 U.S. 837, 842-43 (1984) (holding that if Congress has spoken directly to the disputed issue of statutory construction, "that is the end of the matter; for the court, as well as the agency, must give effect to the unambiguously expressed intent of Congress").

(34) *Nat'l Lime Ass'n v. EPA*, 627 F.2d 416, 443 (D.C. Cir. 1980) (emphasis added).

(35) *See* S. Rep. No. 228, 101st Cong., 1st Sess. 169 (1989).

(36) *See S. Rep. No. 228, 101st Cong., 1st Sess. 133-34 (1989)*.

(37) *See, e.g., Tanners' Council of America v. Train*, 540 F.2d 1188, 1193 (4th Cir. 1976) (deeming Clean Water Act effluent limitations guidelines not achievable where plants in EPA's database were "capable of meeting the limitations for some, but not all, of the pollutant parameters").

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Douglas A. McWilliams

Commenter Affiliation: American Municipal Power

Document Control Number: EPA-HQ-OAR-2002-0058-3685-A2

Comment Excerpt Number: 27

Comment: MACT Floors Must Be Based on the Overall Performance of Actual Sources and Not on a Pollutant-by-Pollutant Basis

The proposed MACT standards rely on a pollutant-by-pollutant analysis that uses a different set of best-performing sources for each separate HAP standard. The result is a set of standards that reflect the hypothetical performance of a set of sources that simultaneously achieve the greatest emission reductions for each and every HAP without regard to whether such sources actually exist. This approach results in unachievable limits and is contrary to the language of section 112. The Clean Air Act unambiguously directs EPA to set standards based on the overall performance of *sources*. Sections 112(d)(1), (2), and (3) specify that emissions standards must be established based on the performance of "sources" in the category or subcategory and that EPA's discretion in setting standards for such units is limited to distinguishing among classes, types, and sizes of sources - it has no authority to distinguish sources by individual pollutant.³³ EPA's pollutant-by-pollutant approach results in a set of emission limits that do not reflect the performance of any existing "source." Although EPA has forecasted that some sources in the coal-fired subcategories can meet all of the emission limits, it is unlikely that these sources can meet all of the emission limits on a consistent basis. EPA's conclusion is based on the results of

reported stack test data that does not take into account the performance of the source over different operating loads, seasons, and fuel mixtures. In fact, vendors have confirmed that they will be unable to guarantee CO limits for coal -fired units at the levels in the Proposed Rule. EPA must revise its emission limits to reflect the performance of actual sources able to meet all emission limits simultaneously. Municipal utilities will benefit from the less stringent limits that reflect the true performance of actual sources as mandated by the Act.

[Footnote 33: Sierra Club v. EPA, 551 F.3d 1019, 1028 (D .C. Cir. 2008).]

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Richard D. Garber

Commenter Affiliation: Boise Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3686-A2

Comment Excerpt Number: 6

Comment: EPA should revise its methodology in the calculation MACT floor for various pollutants and subcategories so that the limits can be consistently achieved by boilers that make up part of the floor. The proposed standards continue to be more stringent in some cases than needed to assure protection of health and the environment from industrial boiler HAP emissions and to fully meet EPA's obligations under the Clean Air Act.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

103E. MACT Floor Methodology: 3x RDL [DENIED PETITIONER ISSUE]

Commenter Name: Mary Sullivan Douglas

Commenter Affiliation: National Association of Clean Air Agencies (NACAA)

Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1

Comment Excerpt Number: 6

Comment: More than any other factor, EPA’s definition of “Best Performing Unit” leads to overestimates of performance of the best performing units. It creates a situation where units with high UPLs are designated as “best performing units” and displace better performing units in the “top 12 percent” category. EPA is obliged to base the existing source MACT floor on the performance of the “best performing units” and has offered no plausible explanation for its decision.

EPA has used two (or three) different methods for establishing the “performance” of the average of the best-performing 12 percent. In selecting the units to be included in the top 12 percent, EPA assumed that the performance of those units was demonstrated by the best test result.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

103H. MACT Floor Methodology: Exclusion of Co-Fired Data [DENIED PETITIONER ISSUE]

Commenter Name: Ahmed Idriss, Capital Power Corporation
Commenter Affiliation: CPI USA North Carolina (CPI NC)
Document Control Number: EPA-HQ-OAR-2002-0058-3524-A1
Comment Excerpt Number: 1

Comment: CPI NC does not support the EPA’s methodology for establishing emissions limits based limits for fuel on single fuel type facilities. In the Proposed Rule, EPA proposes to establish emissions at least 90% biomass in the case of PM and CO biomass categories, and 90% coal in the case of PM and CO coal categories. While this method may be appropriate for single fuel facilities, it does not reasonably consider maximum achievable control technologies for facilities utilizing multiple fuel types.

Capital Power recommends using fuel and fuel mixture variability for multi-fuel facilities in determining the top 12% of such facilities for the MACT floor. This approach is more reasonable because it captures each facility’s operational and fuel variability.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Mary Sullivan Douglas
Commenter Affiliation: National Association of Clean Air Agencies (NACAA)
Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1
Comment Excerpt Number: 34

Comment: In its most recent proposals EPA has employed a different approach to the determination of the emission limit to be applied. Whereas, in the 2011 rulemaking any test result where the source was combusting more than 10 percent coal was used in determining the MACT floor for the coal subcategories, in its most recent calculation of MACT floors EPA only used data from tests where the source was burning 90 percent or more coal during the test for existing sources and 100 percent coal for new sources. We believe that a 90-percent threshold is appropriate for the definition of this subcategory and appropriate for establishing a limit for “coal-fired” units, but see no reason to have a higher threshold for new units. Having done so, however, EPA needs to revise its definition of the subcategory to be consistent with its approach in setting standards. EPA may not exclude results from testing of clean sources within the subcategory. We recommend that fuel-based subcategory limits and subcategory definitions each be based on a minimum (e.g., 85-95 percent) usage of the fuel type and that EPA devise an approach for establishing emission limits for units that burn mixed fuels in lesser amounts.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Steve Gossett
Commenter Affiliation: Eastman Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3669-A2

Comment Excerpt Number: 16

Comment: Combination coal/biomass units should be defined as coal units so that they are subject to emission limits applicable to the combination of fuels they burn.

Discussion: If EPA responds to our comment request to separate coal boilers from biomass boilers to set PM, Hg, and HCl emission limits, a problem will surface concerning certain combination boilers specifically designed to burn varying percentages of coal, bark (biomass), and other solid fuel such as tire-derived fuel and old corrugated containers rejects. The current definition defines any such unit that burns greater than 10 percent biomass on an annual heat input basis as a "unit designed to burn biomass/bio-based solids". EPA did this so that these units would be subject to carbon monoxide limits derived from pure biomass units. Then, as EPA describes on page 15636 of the March 21, 2011 final rule preamble, they attempt to resolve the combination boiler dilemma by combining all solid fuel boilers into one subcategory for fuel based pollutants:

For combined fuel units that combust solid fuels, due to the many potential combinations and percentages of solid fuels that are or can be combusted, for the fuel-based pollutants, EPA selected the option of combining the subcategories for solid fuels into a single solid fuel subcategory. For the fuel-based pollutants, this alleviates the concerns regarding changes in fuel mixtures, promotion of combustion of dirtier fuels, and the implementation and compliance concerns.

We maintain that this change in subcategories, designed primarily to address combination units, is inappropriate for both combination units and pure coal-fired units. The reason is, as we have discussed above, that they are different types of boilers than biomass boilers and have very different emission profiles than biomass boilers due both to their design and the fuels they are designed to combust.

EPA should define any solid fuel boiler that burns at least 10 percent coal on an annual heat input basis as being in the "unit designed to burn coal/solid fuel subcategory". Because these combination boilers are specifically designed to burn a variety of materials (coal, bark, TDF, OCC rejects, etc.) that do have significant and varying chlorine and mercury contents, such classification is equitable for these units. This approach affords them the compliance options to either (1) shift to a cleaner relative mix of feeds (*e.g.* less coal and more bark or OCC rejects) or (2) install control technology to meet the emission standards. Just as with coal boilers, it would not be fair or appropriate to require these units to meet emission standards set by biomass boilers, some of the top performers of which have very low levels of mercury and chlorine in their feeds.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Heather Parent

Commenter Affiliation: Maine Department of Environmental Protection

Document Control Number: EPA-HQ-OAR-2002-0058-3691-A2

Comment Excerpt Number: 4

Comment: We are concerned, however, that some of the emission standards are not appropriate, particularly for units in Maine that burn multiple fuels at the same time. Did the emissions data that was relied on to develop the proposed emission standards for these subcategories include testing or CEM data from units that were combusting multiple fuels (e.g., coal, biomass, tire derived fuel, fuel oil, etc.) at the same time? If not, Maine DEP recommends that EPA establish appropriate limits for these types of multi-fuel fired units.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Ahmed Idriss, Capital Power Corporation

Commenter Affiliation: CPI USA North Carolina (CPI NC)

Document Control Number: EPA-HQ-OAR-2002-0058-3524-A1

Comment Excerpt Number: 1

Comment: CPI NC does not support the EPA’s methodology for establishing emissions limits based limits for fuel on single fuel type facilities. In the Proposed Rule, EPA proposes to establish emissions at least 90% biomass in the case of PM and CO biomass categories, and 90% coal in the case of PM and CO coal categories. While this method may be appropriate for single fuel facilities, it does not reasonably consider maximum achievable control technologies for facilities utilizing multiple fuel types.

Capital Power recommends using fuel and fuel mixture variability for multi-fuel facilities in determining the top 12% of such facilities for the MACT floor. This approach is more reasonable because it captures each facility’s operational and fuel variability.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Mary Sullivan Douglas

Commenter Affiliation: National Association of Clean Air Agencies (NACAA)

Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1

Comment Excerpt Number: 34

Comment: In its most recent proposals EPA has employed a different approach to the determination of the emission limit to be applied. Whereas, in the 2011 rulemaking any test result where the source was combusting more than 10 percent coal was used in determining the MACT floor for the coal subcategories, in its most recent calculation of MACT floors EPA only used data from tests where the source was burning 90 percent or more coal during the test for existing sources and 100 percent coal for new sources. We believe that a 90-percent threshold is appropriate for the definition of this subcategory and appropriate for establishing a limit for “coal-fired” units, but see no reason to have a higher threshold for new units. Having done so, however, EPA needs to revise its definition of the subcategory to be consistent with its approach in setting standards. EPA may not exclude results from testing of clean sources within the subcategory. We recommend that fuel-based subcategory limits and subcategory definitions each be based on a minimum (e.g., 85-95 percent) usage of the fuel type and that EPA devise an approach for establishing emission limits for units that burn mixed fuels in lesser amounts.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Steve Gossett

Commenter Affiliation: Eastman Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3669-A2

Comment Excerpt Number: 16

Comment: Combination coal/biomass units should be defined as coal units so that they are subject to emission limits applicable to the combination of fuels they burn.

Discussion: If EPA responds to our comment request to separate coal boilers from biomass boilers to set PM, Hg, and HCl emission limits, a problem will surface concerning certain combination boilers specifically designed to burn varying percentages of coal, bark (biomass), and other solid fuel such as tire-derived fuel and old corrugated containers rejects. The current definition defines any such unit that burns greater than 10 percent biomass on an annual heat input basis as a "unit designed to burn biomass/bio-based solids". EPA did this so that these units would be subject to carbon monoxide limits derived from pure biomass units. Then, as EPA describes on page 15636 of the March 21, 2011 final rule preamble, they attempt to resolve the combination boiler dilemma by combining all solid fuel boilers into one subcategory for fuel based pollutants:

For combined fuel units that combust solid fuels, due to the many potential combinations and percentages of solid fuels that are or can be combusted, for the fuel-based pollutants, EPA selected the option of combining the subcategories for solid fuels into a single solid fuel subcategory. For the fuel-based pollutants, this alleviates the concerns regarding changes in fuel mixtures, promotion of combustion of dirtier fuels, and the implementation and compliance concerns.

We maintain that this change in subcategories, designed primarily to address combination units, is inappropriate for both combination units and pure coal-fired units. The reason is, as we have discussed above, that they are different types of boilers than biomass boilers and have very different emission profiles than biomass boilers due both to their design and the fuels they are designed to combust.

EPA should define any solid fuel boiler that burns at least 10 percent coal on an annual heat input basis as being in the "unit designed to burn coal/solid fuel subcategory". Because these combination boilers are specifically designed to burn a variety of materials (coal, bark, TDF, OCC rejects, etc.) that do have significant and varying chlorine and mercury contents, such classification is equitable for these units. This approach affords them the compliance options to either (1) shift to a cleaner relative mix of feeds (*e.g.* less coal and more bark or OCC rejects) or (2) install control technology to meet the emission standards. Just as with coal boilers, it would not be fair or appropriate to require these units to meet emission standards set by biomass boilers, some of the top performers of which have very low levels of mercury and chlorine in their feeds.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Heather Parent
Commenter Affiliation: Maine Department of Environmental Protection
Document Control Number: EPA-HQ-OAR-2002-0058-3691-A2
Comment Excerpt Number: 4

Comment: We are concerned, however, that some of the emission standards are not appropriate, particularly for units in Maine that burn multiple fuels at the same time. Did the emissions data that was relied on to develop the proposed emission standards for these subcategories include testing or CEM data from units that were combusting multiple fuels (e.g., coal, biomass, tire derived fuel, fuel oil, etc.) at the same time? If not, Maine DEP recommends that EPA establish appropriate limits for these types of multi-fuel fired units.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Alternative CO CEMS-Based Standards

4A. CO CEMS as Alternative Standard

Commenter Name: Paul Noe
Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.
Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1
Comment Excerpt Number: 80

Comment: EPA originally developed a CO standard that boilers must meet at all times based on 3 run stack tests with no acknowledgment of the highly variable nature of CO emissions in solid fueled boilers. CO emissions from boilers can be highly variable, especially when fuel mix and load change. Facilities are typically required to conduct stack tests at least 90 percent of full load during normal operating conditions. A CO stack test is a small snapshot in time captured during the best operating conditions.

It stands to reason that the Boiler MACT standards should be "internally consistent," in that the test methods or measurement techniques used to gather the data used to set the standard should also be used to show compliance with the standard once it becomes applicable to affected facilities. If the test methods or measurement techniques are not consistent (or, at least, shown to be comparable), the compliance methods will not be a true or reasonable measure of compliance with the standard.

The CO standards included in the final Boiler MACT create this problem. The standards are based on short term stack tests that measured CO over a relatively short period of time during which operating conditions were stable, consistent, and optimal. However, many affected units already have CO CEMS for reasons unrelated to the Boiler MACT. These CEMS take data over long periods of time and, therefore, reflect variability in unit operations that was not measured in the stack tests on which the standards are based and was not factored into the test-based standards. Thus, these CO CEMS take data that are not compatible with the test-based standards and cannot reasonably be used to show compliance with these standards.

We appreciate that EPA has realized this problem and proposed to solve it by setting an alternative CO limit for units that choose to comply using CO CEMS. We note that EPA has broad authority in setting standards under § 112(d) to "distinguish among classes, types, and sizes of sources within a category or subcategory in establishing such standards." CAA § 112(d)(1). Industrial boilers with CO CEMS constitute a distinct and easily definable "class" or "type" of source, characterized by the existence of a CO CEMS and distinguished from other boilers by the abundance of CO data that they generate. Therefore, it is reasonable for EPA to set a separate standard for these sources that is compatible with the greater variability that these data reflect.⁴³

Response: The EPA thanks the commenter for their support of alternative CO CEMS-based limits.

Commenter Name: Holly R. Hart

Commenter Affiliation: United Steel Workers (USW)

Document Control Number: EPA-HQ-OAR-2002-0058-3498-A1

Comment Excerpt Number: 5

Comment: EPA has made many changes throughout the rulemaking process to make the carbon monoxide (CO) emissions limits proposed more achievable for operators (see pages 80612 ff.). Nevertheless, there remains significant concern among industry that even these changes do not sufficiently allow for the extreme variability of carbon monoxide emissions and will need further modification. USW urges EPA to give full consideration to data submitted by industry sources that indicate need for the CO emissions limits to be further modified in order to allow them to be achievable by operators.

Response: EPA acknowledges the variability in CO emissions for the units subject to this rule. The proposed CEMS-based limits for each subcategory have been recalculated in the final rule based on the rolling average of longest duration allowed by the available data, up to a maximum of a 30-day rolling average. The proposed method of considering the maximum rolling average of the top 6 percent was also incorporated into the development of the CEMS-based limits in the final rule. EPA believes these steps properly account for the inherent variability in CO emissions and mitigate concerns over the achievability of CO standards.

EPA considered all data submitted prior to August 8, 2012 in its analyses for the final rule.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 66, 67

Comment: *ACC Supports the Inclusion of Alternate CEMS Based Limits for CO*

EPA originally developed a CO standard that boilers must meet at all times based on 3 run stack tests with no acknowledgment of the highly variable nature of CO emissions in solid fueled boilers. CO emissions from boilers can be highly variable, especially with fuel mix and load

change. Facilities are typically required to conduct stack tests at least at 90 percent of full load during normal operating conditions. A CO stack test therefore is a small snapshot in time captured during the best operating conditions.

It stands to reason that the Boiler MACT standards should be "internally consistent," in that the test methods or measurement techniques used to gather the data used to set the standard should also be used to determine compliance with the standard. If the test methods or measurement techniques are not consistent (or, at least, shown to be comparable), the methods will not be a true or reasonable measure to determine compliance with the standard.

The CO standards included in the Final Boiler Rule present this problem. The standards are based on short-term stack tests that measured CO over a relatively short period of time during which operating conditions were stable, consistent, and optimal. However, many affected existing units already have CO CEMS for reasons unrelated to the rule. These CEMS collect data over long periods of time and, therefore, reflect variability in unit operations that was not measured in the stack tests on which the standards are based and was not factored into the test-based standards. Thus, these CO CEMS data are not compatible with the test-based standards and cannot reasonably be used to determine compliance with these standards.

ACC appreciates that EPA has acknowledged this problem and proposed to solve it by setting an alternative CO limit for units that choose to determine compliance using CO CEMS. ACC notes that EPA has broad authority in setting standards under § 112(d) to "distinguish among classes, types, and sizes of sources within a category or subcategory in establishing such standards." CAA § 112(d)(1). Industrial boilers with CO CEMS constitute a distinct and easily definable "class" or "type" of source, characterized by the existence of a CO CEMS and distinguished from other boilers by the abundance of CO data that they generate. Therefore, it is reasonable for EPA to set a separate standard based on CEMS data for these sources that is compatible with the greater variability that these data reflect.²⁵

Response: The EPA thanks the commenter for their support of alternative CO CEMS-based limits.

Commenter Name: Ahmed Idriss, Capital Power Corporation

Commenter Affiliation: CPI USA North Carolina (CPI NC)

Document Control Number: EPA-HQ-OAR-2002-0058-3524-A1

Comment Excerpt Number: 6

Comment: CPI NC supports the EPA's proposal to use CO CEMS, as further described in Table 2 of the Proposed Rule, as an alternative to CO stack testing and oxygen monitoring. Without such an alternative, CPI NC would be required to install costly monitoring equipment, which would not accurately monitor CO emissions. CPI NC notes that using O₂ CEMS to monitor and regulate emissions for stoker units is inappropriate, as the air flow distributions between under-grate and over-grate air can vary considerably based on unit load and impact the O₂ reading in flue gas. As mentioned by petitioners and EPA, in the Proposed Rule, an emission limit based on CO CEMS data from boilers would more accurately capture true variability in CO emissions over various operating conditions. This approach is a more rational approach for determining MACT floors for boilers and process heaters than a strict 99 UPL because it

contemplates whether top performers can actually meet the emissions limits based on their operating conditions.

Response: The EPA thanks the commenter for their support of alternative CO CEMS-based limits.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 56, 57

Comment: The CO CEMS best performers should be the basis for the CO emission limitations and compliance demonstrations should be allowed using either CO CEMS or stack testing.

Section 112 of the CAA requires that MACT emission limitations be based on the emissions reductions achieved by the best performing unit for new sources or the average emission limitation achieved by the best performing 12% of existing sources in a source category or subcategory. For CO, EPA proposes two different limits based on data from two separate sets of BPH. EPA reports it derived the CO limit for CEMS using data from sources that are not “best performers”¹⁶. EPA has flexibility in how it establishes the best performers and they can use information collected using different methodologies (e.g., stack tests and CEMS). With adequate CEMS data (reflecting operating variability) EPA could, and in this case should, conclude that such data is more representative of “achievable emissions” than is stack test data for CO for some subcategories and thus use the CEMS CO data to develop the numerical emission limit¹⁷. Using the CO CEMS basis for setting the emission limitation would allow EPA to account for the high CO levels that can occur during operating transitions, turndown operations, startups etc. in establishing CO limits that apply at all times. Compliance could then be demonstrated with a CEMS or by stack test.

Best performing units have historically been characterized based on stack tests, because those tests are done near or at design conditions and thus represent the operation at maximum potential emissions and are often the only data available. Averaging time and variability adjustments are then used to correct the stack test derived emission limitation for the vagaries of real operations, where combustion efficiencies are not as ideal as during stack test conditions. CEMS data, on the other hand, can reflect all the operating variability that can occur, but may not represent the emissions potential at maximum conditions as well as stack testing does. For CO, where operating conditions are a much more important variable than is firing rate, CEMS data is probably a much better indicator of variability and achievability than is stack test data and thus is likely to be a much better basis for selecting the best performers, where adequate data is available.

In this specific case, there appears to be no relationship between the CEMS data used to develop the proposed CO CEMS alternative and the stack test based emission limitations listed in Tables 1 and 2 of the proposal for CO, since they represent different units and different operations. This is clearly indicated by the fact that the relationship between the two emission limitations have no pattern (i.e., the CO CEMS limit is higher than the stack test limit in some cases, lower in others

and the ratios of the two limits vary widely), as shown in the following Table. [See submittal for Table 2 Comparison of CO limits]The randomness of the relationship between the two proposed CO limits makes clear that they do not represent related datasets.

On pages 80612-3 of the preamble, EPA explains “To evaluate whether our selection of the units identified as best performers for CO CEMS data correlates to the units identified as best performers for stack test data, we compared the CEMS data and the computed stack test CO MACT floor for each subcategory. Each unit identified as a best performing unit in the CO CEMS analysis had at least one 3-hour CEMS average at or below the corresponding stack test CO MACT floor for the subcategory, which suggests that the units identified as best performers based on the CEMS data are comparable to the units identified as best performers based on the stack test data.” We do not understand why one three-hour CEMS CO value below the stack test limit would be an indicator that these two sets of data are comparable. Compliance is required at all times not for one three-hour period. Thus, we would expect that a CO CEMS should always measure a value below the stack test based limit, if both limits are reflective of “best performers.” In fact, we would suggest that the lack of agreement for most 3-hour periods indicates that the stack test numerical emission limits do not reflect the “best performers” in the subcategory when variability is correctly reflected (i.e., achievability is considered as required by the CAA). Clearly, the stack test based CO limits do not accurately represent the performance of the best performers over time and are not achievable by the best performing sources as required by section 112(d) of the CAA.

In the dual standard approach of the proposal, we would expect some regulators to require that every occurrence of a higher CEM reading than the stack test limit (the primary CO limit in this proposal) be treated as credible evidence of a deviation, reportable under both the applicable MACT rule and Title V. Thus, we expect establishing two alternative CO limits, as is proposed, will cause untold confusion, regulatory burdens, erroneous deviations, and violation notices.

Under other MACT rules, the emission limits are derived from one set of emission sources (the best performers) almost always based on stack test information corrected for operating variability. A choice of methodologies is then provided for demonstrating compliance. Those compliance methodologies typically include use of a CEMS, where such monitors are available and proven. However, the CEMS is used to show compliance with the emission limit derived for the best performers just as other methodologies (e.g., periodic stack tests, parameter monitoring) do. We believe a similar approach should be used here, but with the CO emission limit established based on best performers being selected based on the CEMS data, where it is adequate, or adjusted for variability with consideration of the variability shown by the CEMS data, where the CEMS data is inadequate for establishing the best performers.

Response: In the March 2011 final rule, the EPA promulgated CO MACT emission limits, as a surrogate for non-D/F organic HAP emissions, based on CO stack test data and MACT floor analyses, as well as compliance provisions requiring annual performance testing, an oxygen content operating limit, and continuous oxygen monitoring. The EPA received petitions for reconsideration requesting, among other things, a rule revision to allow units with CO CEMS to use them to demonstrate compliance in lieu of performance testing and oxygen monitoring. Petitioners requested that EPA develop an alternative form of the CO emission limit, based on the use of CO CEMS and a longer averaging period such as a 30-day rolling average. As suggested by petitioners, the EPA proposed alternative CO emission limits based on CO CEMS

data, where sufficient data were available, based on 10-day or 30-day rolling averages, and solicited additional CO emissions data. The alternative CO CEMS-based limits were based on data that excluded periods of startup and shutdown. For more information on the alternative CO CEMS-based limits and periods of startup and shutdown, see the response to comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 84. This excerpt may be found in the CO CEMS “Averaging Time and Rolling Average Length” section of this comment response document.

The commenters concede that “EPA has flexibility in how it establishes the best performers” and “can use information collected using different methodologies (e.g., stack tests and CEMS)” but argue that EPA should finalize only one set of CO emission limits, based on CO CEMS data unless such data is lacking, and remove the stack test-based CO limits as an option in the rule. The EPA has considered the commenters’ arguments and reaffirms its position that the alternative CO CEMS-based limits are well-supported based on the information available to the EPA, and the commenters have not identified a persuasive reason to eliminate the ability of sources to comply with either the CO stack test-based limits or the alternative CO CEMS-based limits. In these comments, the commenters assert that a comparison between the CO CEMS data and stack test-based limits (or alternatively the CO CEMS-based limits and the stack test-based limits) show that there is no “pattern” or “relationship” between the two. The commenters fail to recognize that the EPA typically has a limited amount of information when developing MACT standards, and the EPA may rely on the information it has available to develop reasonable estimates of the emissions of best performing sources. As discussed in the preamble to the proposed rule (see memorandum titled “CO CEMS MACT Floor Analysis (November 2011) for the Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants – Major Source” in the docket), the EPA has very limited CO CEMS data, often for only one or two units, in each of the subcategories for which we are setting alternative CO CEMS-based limits (and we are not setting alternative standards for several subcategories in which we do have sufficient CEMS data). Although we solicited additional CO CEMS data in the December 2011 notice of proposed rulemaking, we only received CO CEMS data for five subcategories. Accordingly, there is still very little overlap in the stack test and CEMS datasets, and it is unsurprising that the two different datasets, largely from different units, resulted in MACT floor analyses that are composed of different units within each subcategory and MACT emission limits that do not bear a direct correlation to each other, also considering that they were evaluated based on different averaging periods.

The commenters asked EPA to determine that the CEMS dataset is better suited for setting MACT standards than the stack test dataset such that the CEMS data, where available, should be the sole basis for CO standards. The EPA disagrees and believes that each dataset may be used to set technically sound and legally justified MACT standards. We note there are advantages and disadvantages to using either dataset. The stack test data are much more abundant, accounting for significantly more units and facilities in each subcategory. The CEMS data include more operating conditions than those during performance tests, as discussed in the memorandum titled, “CO CEMS MACT Floor Analysis (August 2012) for the Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants – Major Source” in the docket. The CEMS-based limits differ from the stack test-based limits in that the CEMS-based limits have 10 or 30 day averaging periods. The EPA sees no inconsistency in applying its MACT methodology to the two datasets, where data are available, resulting in one set of standards based on stack test data and a second set of alternative

standards, with 10 or 30 day averaging periods, based on CEMS data. Each set of standards is based on relevant information available to EPA and complies with the statutory requirements for establishing MACT standards. Indeed, the commenters' contentions could lead to the opposite conclusion that the more abundant stack test data are better suited for setting MACT standards than the CEMS data, as suggested by comments from the Wisconsin DNR, addressed elsewhere in this document.

In addition, setting 10-day and 30-day CO emission limits based on CEMS data, without providing a short-term stack test-based limit as an option, would not make sense unless EPA were to mandate CO CEMS for every unit, which we expressly are not doing. Specifically, if a unit lacking a CO CEMS were required to comply with a 10-day or 30-day CO limit, there would be no basis to determine continuous compliance. Although the commenters say that compliance with a CEMS-based limit could be demonstrated by a CEMS "or by a stack test", they do not explain how the latter would be possible. For example, a stack test could not be run for the duration of a 10-day or 30-day averaging period, and if a source attempted to use a stack test in conjunction with continuous oxygen monitoring in lieu of a CO CEMS, the oxygen content operating limit would need to be based on the lowest oxygen content recorded while complying with the CO limit for a full averaging period, which again would necessitate a CO CEMS at least for purposes of setting the oxygen content operating limit. Accordingly, mandating compliance with the 10 and 30 day CO CEMS-based limits, instead of the stack test-based limits, without also mandating use of CO CEMS for every unit, would not be functional.

We also note that this final rule allows the commenters to comply in the manner they advocate, i.e., with a CO CEMS-based limit using a CO CEMS for compliance purposes.

The EPA disagrees that the presence of stack test-based and CEMS-based CO limits may cause confusion, regulatory burdens, deviations, and violation notices. EPA believes that the final rule clearly indicates the compliance approaches available to sources, and the flexibility in choosing the method of compliance allows sources significant flexibility and the ability to plan for such situations.

The EPA has requested and received information from the ICR process based on two different sets of data. We agree with the commenter that these data sets are not overlapping, but rather form two distinct and different sets of data from which to evaluate source emissions. As such, the final rule provides two different paths for source operators to achieve compliance; either using a certified CO CEMS or by conducting annual emissions testing and using an O₂ CEMS or O₂ trim system as a parametric monitor. The final rule also provides that sources with certified CO CEMS must comply with the ten or 30 day rolling average standard, depending on the particular subcategory, while sources without a certified CO CEMS must demonstrate compliance through an annual stack test and O₂ parametric monitoring. We do not intend that the stack test-based limits would apply to a unit using a certified CO CEMS, nor do we intend that the alternative CO CEMS-based limits would apply to a unit without a certified CO CEMS, relying instead on an annual stack test and O₂ monitoring.

Commenter Name: Bart Sponsellar

Commenter Affiliation: Wisconsin Department of Natural Resources (DNR)

Document Control Number: EPA-HQ-OAR-2002-0058-3527-A1 and -A2

Comment Excerpt Number: 5, 6, 18, 19, 20, 21

Comment: EPA can allow sources to use the CO/O₂ CMS trim system as a parametric monitoring alternative in place of meeting a continuous CO CEMS emission limitation. Under this approach the source periodically (biennial suggested) demonstrates compliance with the primary stack test based emission limit. A correlation is determined of stack test CO to the CO measured using the CO/O₂ CMS system over normal load ranges. The CMS CO concentration then becomes the value to be monitored on a continuous basis. EPA proposed this same type of approach using a PM CMS in place of a PM CEMs for continuous compliance. The parametric CO correlation can also show a source is in compliance with the stack test emission limit at full load but can also show that a source operating under good combustion at lower loads may emit at higher CO levels. We also propose that a source with a CO/O₂ CMS trim system be allowed to determine an alternative CO emission limitation at full load, if appropriate.

EPA is proposing to allow demonstrating compliance with carbon monoxide (CO) emission limitations by using a CO CEMs system. EPA is also proposing that a separate emission limit be established for the CEMs based compliance demonstration in place of the CO limit established based on stack test results.

The Department supports allowing the use of a CO CEMs system for demonstrating compliance. However, the Department believes that EPA should not establish a separate CO emission limitation for this compliance demonstration. A source using a CO CEMs should be allowed to demonstrate compliance with either the primary stack test based CO emission limitation or establish a correlation of CO emissions and good combustion for that source. Further, the source should be able to use a CO continuous monitoring system (CMS) in conjunction with stack testing every two years. Such a source would also establish a correlation between CO CMS data and good combustion or the CO CMS data and the stack emission limit.

First this discussion is premised on the fact that no sources included in the CO stack test or CEMs based floors have a catalyst system for controlling CO emissions; i.e. all CO emission limitations are based on good combustion. EPA has further defined through discussions of this and previous MACT notices that good combustion is the basis for reducing organic toxics including dioxins and furans. EPA has simply determined that CO is an appropriate surrogate for good combustion. Therefore, good combustion is the basis for all organic toxics requirements.

The Department feels establishing a carbon monoxide (CO) CEMs based emission limitation from limited data or data from sources different from the identified 12% best performing sources is problematic.

EPA should not establish a separate CO CEMs emission limitation for compliance on a continual basis. From a methodology point of view EPA does not have CEMs data for all sources identified as the best performers based on a stack test. Instead EPA is using CEMs data from available sources. As a result EPA is identifying two different groups of best performers based on stack test data and CEMs data. EPA simply should not follow an approach where there is not an identified single set of best performers. Two different pools of best performers means that EPA is not correctly identifying the pool of best performers or is incorrectly assuming that best performers can be identified. This latter point will be discussed in more detail. Further it is not

likely, without requiring further testing, that EPA will receive sufficient CEMs data from the pool of best performing sources identified by stack test data to develop a CEMs based emission limit for the same set of sources in a statistically sound manner.

EPA's analysis demonstrates that it is problematic to establish continuous CO emission limitations which apply to all sources even at the sub-category level. In looking at the proposed CO CEMs limits there are multiple categories where they are both more and less stringent than the stack test CO limit. One reason for this is because the CEMs data is based on normal operating levels versus the full operating level required under the stack test requirement. This shows that the stack test value does not represent good combustion at different operating levels for the source category. We believe that further evaluation of CEMs data available for sources currently identified as best performers will show that CO levels at good combustion will vary with load at the same source. This assertion is based on the Department's experience that sources with CO CEMs or CMS systems will use that data to operate as efficiently as possible. At a minimum, the difference between CO CEMs and stack test based limits shows that CO levels representing good combustion can vary significantly between sources. From this information and its past experience the Department concludes that a single CO value should not be set to represent good combustion at one source or between sources.

In lieu of setting a CO CEMs emission limitation the Department believes that a better approach is to retain the stack test emission limitation and allow continuous compliance with a CO CMS or parametric monitoring system. EPA recognized the value of CMS systems versus CEMs systems in proposing the PM CMS approach. EPA also recognized the value of a CMS system for continuous best operation of a source in proposing oxygen trim systems in place of only monitoring oxygen for continuous parametric monitoring requirements.

Under this CO CMS approach a source would establish a correlation during the initial stack testing between the CO emission limitation, CO CMS concentrations and good combustion of the unit at different normal load levels. This approach acknowledges that a source may operate at higher CO levels in achieving good combustion at lower loads. But that good combustion is being achieved at all times. This is corroborated for the source by meeting the CO emission limit at full load. Under this approach the operator should also be able to establish an alternative CO emission limitation at full load based on good combustion for specific fuel types. Such an alternative would have to be approved by the delegated authority. Finally, when using a CO CMS approach a source should not have to perform stack testing more frequently than every two years.

Response: For a response to concerns over variability in CO emissions, see response to comment EPA-HQ-OAR-2002-0058-3498-A1, excerpt 5.

For a response to comments regarding top performers differing between the stack test-based limits and CO CEMS-based limits, please see response to comment EPA-HQ-OAR-2002-0058-3677-A2, excerpts 56 and 57.

The EPA requested CO CEMS data from all sources during the initial ICR and made subsequent requests to source operators for data during reconsideration. All data that were received were factored into the analysis of the CO CEMS-based emission limits. However, only limited CO CEMS data were received.

Work practice standards have been established for the control of dioxin and furan emissions. The EPA disagrees with the commenter that CO is treated as a surrogate for good combustion; CO is selected as a surrogate for organic HAP. The commenter's suggestion to use continuous parameter monitoring to show "good combustion" even if exceeding applicable limits would be unjustified where, as here, viable emission measurement and monitoring approaches such as oxygen monitoring and, alternatively, CO CEMS are available.

The EPA agrees with the commenter that, where available, CO CEMS data can provide a better measure of emissions variability than a stack test value.

In the final rule, all units subject to a CO emission limitation must install, operate, and maintain either a CO CEMS or oxygen analyzer system. Oxygen trim systems are an acceptable oxygen analyzer system. Units which employ an oxygen trim system or other type of oxygen analyzer system are subject to operating limits and an annual performance test. Annual performance tests were selected instead of biennial performance tests because of the potential in this source category for operating conditions and the associated emissions to vary over time.

For units with a certified CO CEMS, the final rule requires the use of the CO CEMS to demonstrate compliance with the alternative CO CEMS-based limits. A certified CO CEMS is a CEMS that meets the Performance Specifications outlined in §63.7525 of the final rule. If a CO CEMS is not certified, the source cannot use the CO CEMS to demonstrate compliance and must instead perform annual performance testing and continuous oxygen monitoring to demonstrate compliance with the applicable stack test-based CO limit. A non-certified CEMS cannot be used to demonstrate compliance with a CEMS-based limit because it does not produce an accurate enough measurement. Sources may use the time until the compliance date specified in §63.7495 to establish certification of a pre-existing CO CEMS. CO CEMS may not be used to demonstrate compliance with a stack test-based limit due to the operational load requirements during performance testing.

Commenter Name: David A. Buff, Golder Associates Inc.

Commenter Affiliation: Florida Sugar Industry (FSI)

Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1

Comment Excerpt Number: 12

Comment: The Proposed Boiler MACT Rule appears to allow the use of either an oxygen analyzer system (O₂ monitoring system) or a CO CEMS. See Section 63.7525(a); 76 F.R. 80636. During the reconsideration process, EPA should clarify that units that already have an installed CO CEMS may elect to use an O₂ monitoring and trim system, instead of the CO CEMS, as their compliance method. This option is appropriate because the location of the CO CEMS, the physical or operational limitations of the CO CEMS, and other factors affecting data quality assurance with the CO CEMS may not conform to the requirements in the Boiler MACT Rule. (See further discussion in paragraph 9, below, regarding "CEMS-Based CO Limits").

Response: See the response to comment EPA-HQ-OAR-2002-0058-3527-A1 and A2, excerpts 5, 6, 18, 19, 20, and 21.

Commenter Name: Barry Christensen
Commenter Affiliation: Occidental Chemical Corporation (OCC)
Document Control Number: EPA-HQ-OAR-2002-0058-3477-A1
Comment Excerpt Number: 4

Comment: OCC supports the proposed increased flexibility in the compliance monitoring requirements. In particular, where numerical limits must be measured, we support EPA's option to allow either continuous monitoring equipment or stack testing procedures. For example, this includes the proposed carbon monoxide (CO) limits that are based on either stack testing or continuous monitoring. This monitoring flexibility also includes the use of oxygen measuring systems in lieu of continuous CO monitoring systems. We support this as it will certainly lower the economic burden to the affected facilities. However, the option to use a CO CEMS instead of conducting stack sampling and using an oxygen monitor is also available.

Response: The EPA thanks the commenter for their support.

Commenter Name: David A. Buff, Golder Associates Inc.
Commenter Affiliation: Florida Sugar Industry (FSI)
Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1
Comment Excerpt Number: 30

Comment: The FSI applauds EPA's willingness to provide alternative approaches for demonstrating compliance with the CO emission limits in the Proposed Boiler MACT Rule.

Response: The EPA thanks the commenter for their support.

Commenter Name: Michael L. Krancer
Commenter Affiliation: Pennsylvania Department of Environmental Protection (DEP)
Document Control Number: EPA-HQ-OAR-2002-0058-3507-A1
Comment Excerpt Number: 12

Comment: The EPA has received additional data from stakeholders and incorporated all of the data into the boiler MACT database. The new data included additional Hg test runs, PM test runs, dioxin/furan test runs, carbon monoxide (CO) test runs, HCI test runs, TSM test runs, and CO CEMS data. They also received several corrections to the project database and performed additional quality assurance activities on the best performers. The EPA's review of this data resulted in multiple changes to emission limits and the establishment of alternate CO CEMS based emission limits and monitoring for most subcategories.

The DEP commends the EPA on collecting and processing of additional data in order to establish more achievable emission limits and alternate CO CEMS emission limits.

Response: The EPA thanks the commenter for their support.

Commenter Name: Richard Krock
Commenter Affiliation: The Vinyl Institute

Document Control Number: EPA-HQ-OAR-2002-0058-3526-A1

Comment Excerpt Number: 17

Comment: Increased Flexibility Needed for CO Compliance Monitoring

The VI supports EPA's revisions to the monitoring requirements for carbon monoxide (CO) for major source boilers. As an alternative to CO stack testing and oxygen monitoring, EPA proposed the use of a CO continuous emissions monitoring system (CEMS). EPA calculated a CO CEMS-based MACT floor for many subcategories based on data submitted by affected sources that currently use CO CEMS. This revision will lower the economic burden on affected facilities by providing flexibility in emissions monitoring and avoids duplicative requirements for those facilities currently using CO CEMS.

Response: The EPA thanks the commenter for their support.

Commenter Name: Vickie Woods

Commenter Affiliation: Division of Air Quality, North Carolina Department of Environment and Natural Resources (NCDENR)

Document Control Number: EPA-HQ-OAR-2002-0058-3663-A2

Comment Excerpt Number: 17

Comment: Alternate CO limits. As an alternative to CO stack testing and oxygen monitoring, EPA proposes compliance option allowing CO CEMS to comply with an alternate CEMS based emission limit.

NC DAQ supports the development of alternate CO emission limits allowing facilities with CO CEMS the option to comply with an alternate CEMS based emission limit.

Response: The EPA thanks the commenter for their support.

Commenter Name: Robert Cleaves

Commenter Affiliation: Biomass Power Association (BPA) and California Biomass Energy Alliance (CBEA)

Document Control Number: EPA-HQ-OAR-2002-0058-3489-A1

Comment Excerpt Number: 1

Comment: EPA has proposed an alternative longer term averaging time emission limit for carbon monoxide when using CEMS. For biomass boilers this is a 10-day rolling average alternative to the manual 3-hour test. We support this alternative. We believe EPA should clarify that when a boiler is already equipped with a CO CEMS, the CO standard is complied with by meeting either the annual 3-hour manual test or the 10-day CEM standard. In other words, the facility is not required to meet both. Our request is based on our experience with State regulators who we suspect will reason that if a unit is already CO CEMS equipped, as many are per Title V permit requirements, then it should be required to meet the CEMS based CO limit. Conversely, a CO CEMS-equipped boiler may be required to conduct manual CO stack tests to meet permit requirements unrelated to MACT and that a boiler should not have to meet the short term limit if it chooses to meet the CEMS-based MACT standard. To prevent confusion and

misinterpretation, EPA should specify in the final rule that 1) if a unit is CEMS-equipped to comply with non-MACT requirements it can still choose to meet the short term CO limit using manual testing, and 2) if a source chooses to comply with the CO CEMS-based standard, it is not subject to the stack test-based CO standard-even if it conducts CO stack tests for other purposes.

Response: The EPA thanks the commenter for their support of CO CEMS-based alternative standards.

For a response to the comments regarding CO compliance options, see responses to comments EPA-HQ-OAR-2002-0058-3527-A1 and A2, excerpts 5, 6, 18, 19, 20, and 21 and EPA-HQ-OAR-2002-0058-3677-A2, excerpt 56.

Commenter Name: Timothy Serie

Commenter Affiliation: American Coatings Association (ACA)

Document Control Number: EPA-HQ-OAR-2002-0058-3502-A1

Comment Excerpt Number: 9

Comment: ACA generally supports the following proposed changes in the Boiler MACT rule:

EPA's proposed alternative compliance option for facilities that wish to use CO CEMS instead of CO stack testing and oxygen monitoring, so long as EPA clarifies that a source is not subject to the stack test-based CO standard if it chooses to comply with alternative CEMS-based limits

Response: The EPA thanks the commenter for their support of CO CEMS-based alternative standards. For a response to the request for clarification that units are not subject to the stack test-based limits if they opt to demonstrate compliance with CEMS-based limits, please see responses to comments EPA-HQ-OAR-2002-0058-3527-A1 and A2, excerpts 5, 6, 18, 19, 20, and 21 and EPA-HQ-OAR-2002-0058-3677-A2, excerpts 56 and 57.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 68

Comment: It is possible that a CO CEMS-equipped boiler may be required to conduct CO stack tests for reasons unrelated to this rule(e.g., the unit may have a PSD permit or state construction permit that requires such testing). To prevent confusion, EPA should clearly specify in the reconsidered final rule that, if an affected source chooses to comply with the CO CEMS-based standard, it is not subject to the stack test-based CO standard – even if it conducts CO stack tests for other regulatory purposes. Conversely, EPA should also clarify that even if a unit has CO CEMS installed, it may choose to comply with the stack test-based CO limit, and in this case, CO CEMS data are not to be used to demonstrate compliance.

Response: See the response to comments EPA-HQ-OAR-2002-0058-3527-A1 and A2, excerpts 5, 6, 18, 19, 20, and 21 and EPA-HQ-OAR-2002-0058-3677-A2, excerpts 56 and 57.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 34, 35, 36

Comment: For coal-fired fluidized bed combustors (FBCs), pulverized coal (PC) and stoker units, EPA proposed 10-day rolling average (RA) limits of 59, 28 and 34 ppm @3% O₂, respectively. These limits were derived by calculating a 99.0% upper predictive limit (UPL) for daily averages corresponding to 1 coal FBC (IARoquetteAmerica), 1 coal PC (VAsmurfitStoneWestpt) and 1 coal stoker unit (WVDuPontWashingtonWorks). EPA also estimated an alternate limit which was based on the maximum 10-day rolling average for the duration of the available data. These limits were estimated at 78, 35 and 34 ppm @3% O₂ for the FBC, PC and stoker categories, respectively. Only the WVDuPontWashingtonWorks stoker unit was in the stack test-based MACT floor for its category. The VAsmurfitStoneWestpt PC unit was ranked No. 7 in the stack test-based MACT floor list with the top 5 making the floor. The IARoquetteAmerica FBC unit did not figure in the top 16 FBCs listed by EPA in relation to the stack test-based MACT floor. Only 52 daily averages were used to derive the limit for FBCs, 60 daily averages were used to derive the limit for PCs, and 31 daily averages were used to derive the limit for stokers. Clearly, these limits were derived based on very little data.

As discussed in more detail elsewhere in these comments, for units that already have CO CEMS for reasons unrelated to the IB MACT, compliance with the IB MACT stack-test-based CO emissions limitations would be difficult to maintain. Stack tests are required to be run under representative operating conditions, which typically is defined as operating at or near full load consistently for the duration of the stack test. In sharp contrast, CEMS take emissions data on a near-continuous basis, which means CEMS emissions measurements reflect significant variability in emissions (for example, due to load swings and low load conditions) that was not measured during the stack tests used to set the CO standard. This problem is not overcome by statistical manipulation of the CO standard, such as accounting for variability using the UPL method, because such statistical methods unrealistically extrapolate only from the variability measured during stack tests and the variability between stack tests. In other words, this is a classic "apples and oranges" situation where emissions data from CO CEMS are incompatible with emissions data from stack tests used to set the CO standard.

One way for EPA to resolve this incompatibility is to determine that emissions data from CO CEMS are not credible evidence for purposes of assessing compliance with the IB MACT stack-test-based CO emissions limitations. As the Agency explained in the "credible evidence rule," data and information derived from methods other than the specified reference test method (so-called "non-reference test data") are relevant to showing compliance only to the degree that "the appropriate reference test would have shown a violation." 62 Fed. Reg. 8314, 8323 (Feb. 24, 1997). Because the IB MACT CO standards are based on stack test data, and because the stack tests on which the standards are based were required to be conducted during representative operating conditions (*i.e.*, consistently operating at or near full load), then by definition CO CEMS data taken during periods of operation that do not reflect "representative operating conditions" are not data that are relevant to showing compliance with the standards.

In other words, the stack test data on which the standards are based reflect operation during a narrow, limited, and optimum set of conditions. Thus, CO CEMS data that are taken during periods of operation that do not reflect those conditions are not relevant to determining whether an affected source is in compliance with the standard.

Response: The final rule does not exempt certified CO CEMS data from the credible evidence rule. For clarification regarding CO compliance options, see responses to comments EPA-HQ-OAR-2002-0058-3527-A1 and A2, excerpts 5, 6, 18, 19, 20, and 21 and EPA-HQ-OAR-2002-0058-3677-A2, excerpts 56 and 57.

Commenter Name: Richard D. Garber

Commenter Affiliation: Boise Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3686-A2

Comment Excerpt Number: 17, 18

Comment: EPA should revise certain continuous monitoring and reporting requirements that are infeasible and problematic.

EPA should determine that data from CO CEMS shall not be used to show compliance with stack test-based CO emissions limitations.

As discussed in the previous section, for units that already have CO CEMS for reasons unrelated to the Industrial Boiler MACT, compliance with the Industrial Boiler MACT stack-test-based CO emissions limitations would be difficult to maintain. Boise has two such units at its paper mills that will be required to demonstrate continuous compliance with the CO CEMS emission limit. Stack tests are required to be run under representative operating conditions, typically defined as operating at or near full load consistently for the duration of the stack test. In sharp contrast, CEMS take emissions data on a near-continuous basis, which means CEMS emissions measurements reflect significant variability in emissions (for example, due to load swings and low load conditions) that was not measured during the stack tests used to set the CO standard.

This problem is not overcome by statistical manipulation of the CO standard, such as accounting for variability using the UPL method, because such statistical methods unrealistically extrapolate only from the variability measured during stack tests and the variability between stack tests. In other words, this is a classic "apples and oranges" situation where emissions data from CO CEMS are incompatible with emissions data from stack tests used to set the CO standard.

One way for EPA to resolve this incompatibility is to determine that emissions data from CO CEMS are not credible evidence for purposes of assessing compliance with the Industrial Boiler MACT stack-test-based CO emissions limitations. As the Agency explained in the "credible evidence rule," data and information derived from methods other than the specified reference test method (so-called "non-reference test data") are relevant to showing compliance only to the degree that "the appropriate reference test would have shown a violation." 62 Fed. Reg. 8314, 8323 (Feb. 24, 1997). Because the Industrial Boiler MACT CO standards are based on stack test data, and because the stack tests on which the standards are based were required to be conducted during representative operating conditions {i.e., consistently operating at or near full load}, then by definition CO CEMS data taken during periods of operation that do not reflect "representative operating conditions" are not data that are relevant to showing compliance with the standards.

In other words, the stack test data on which the standards are based reflect operation during a narrow, limited, and optimum set of conditions. Thus, CO CEMS data that are taken during periods of operation that do not reflect those conditions are not relevant to determining whether an affected source is in compliance with the standard.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpts 34, 35, and 36.

Commenter Name: Philip Lewis

Commenter Affiliation: Michigan Biomass - Grayling Generating Station

Document Control Number: EPA-HQ-OAR-2002-0058-3815-A1

Comment Excerpt Number: 4

Comment: We strongly support: A longer averaging time for CO for boilers already equipped and required to operate CEMs, with adjusted emission levels to reflect the variability we see when operating CEMs compared to short term stack tests.

Response: The EPA thanks the commenter for their support.

4B. Statistical Analysis

Commenter Name: Chris M. Hobson

Commenter Affiliation: Southern Company

Document Control Number: EPA-HQ-OAR-2002-0058-3520-A1

Comment Excerpt Number: 14

Comment: EPA should not determine the final CO CEMS MACT floor based on each unit's minimum 10-day rolling average. This does not fully account for variability. In fact, EPA acknowledges that even the best 6% of units that established the CO CEMS MACT floor did not meet the calculated limit up to 25% of the time. EPA, however, did not propose a remedy.

Response: EPA has revised the methodology used to calculate the CO CEMS-based limits for the final rule. First, we calculated the 99% UPL on the rolling averages of the top 12 percent. Second, the maximum rolling average of the top 6 percent was compared to the calculated UPL. EPA believes the revised methodology fully accounts for the variability in the reported CEMS data sets. Further detail on the revised methodology can be found in the memo titled, "CO CEMS MACT Floor Analysis (August 2012) for the Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP" in the docket.

Commenter Name: Randall D. Quintrell

Commenter Affiliation: Georgia Paper & Forest Products Association

Document Control Number: EPA-HQ-OAR-2002-0058-3451-A1

Comment Excerpt Number: 9

Comment: The proposed CO limits for those units with continuous monitors (e.g., monitors which have been required for other reasons) do not adequately cover the normal range of boiler operations, and as such cannot be met continuously by even those floor units used to establish

these limits. As noted above, in the final rule, EPA should make changes so that the 99.9% UPL is used.

Response: For the reasons detailed in the preamble to the December 23, 2011 proposed reconsideration of the rule, EPA has chosen to retain a 99% UPL for the final rule. The EPA has revised the methodology for CO CEMS-based emission limits by adjusting the UPL equation to better represent the compliance condition, extending the averaging time to 30 days when data was available to make this extension, incorporating new data submissions provided by the commenters, and by incorporating the alternative CO emission limit methodology, which compares the 99% UPL with the maximum CO value from the top 6 percent of units. Please see the memo titled, "CO CEMS MACT Floor Analysis (August 2012) for the Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP" in the docket for details on these changes. The EPA has evaluated the revised emission limits and determined that these changes appropriately reflect the variability of emissions from best performers based on the data available to the EPA.

Commenter Name: Richard D. Garber

Commenter Affiliation: Boise Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3686-A2

Comment Excerpt Number: 16

Comment: Separate comments being submitted by AF&PA and NCASI discuss changes that are needed to the methodology being used to set the CO GEMS-based limits to ensure these limits are achievable. Boise fully endorses the approaches mentioned in the NCASI and AF&PA comments that develop the supporting rationale for use of the 99.9 UPL for establishing the final CO limits for the Boiler MACT rule. Because of the many various boiler designs and differences in solid fuel characteristics, EPA should recalculate the MACT floor and make appropriate adjustments to floor calculations in order to make CO emission limits achievable at all representative conditions.

Response: For a response to the request that a 99.9% UPL be used to establish CO CEMS-based limits, please see response to comment EPA-HQ-OAR-2002-0058-3451-A1, excerpt 9. For a response to the request that CO CEMS-based limits be recalculated with revised methodology, please see response to comment EPA-HQ-OAR-2002-0058-3520-A1, excerpt 14.

Commenter Name: M.L. Steele

Commenter Affiliation: CraftMaster Manufacturing, Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3814-A1

Comment Excerpt Number: 11

Comment: CraftMaster supports the concept discussed in the CO GEM's MACT memo that fuels fired by sources in the MACT Floor should not be process specific but representative of the entire source category. This concept should be applied to each MACT Floor determination especially where there are a limited number of units in the MACT Floor.

Response: The EPA thanks the commenter for their support of MACT floors not being calculated from the combustion of process-specific fuels. The EPA has applied this methodology to all MACT floor calculations for the rule.

4C. Averaging Time and Rolling Average Length

Commenter Name: Traylor Champion

Commenter Affiliation: Georgia-Pacific LLC (GP)

Document Control Number: EPA-HQ-OAR-2002-0058-3465-A1

Comment Excerpt Number: 32

Comment: EPA has determined that a 30-day rolling average is appropriate for parameter monitoring and demonstration of continuous compliance with O₂ operating limits established for demonstration of continuous CO emissions compliance. EPA notes in the preamble that *“We are aware from studies of emissions over long averaging periods that long term (e.g., 30-day) average emissions for operating in compliance will have a variability of about half of that represented by the results of short term testing. Given that short term tests are representative of distinct points along a continuum of that inherent operational variability, we believe it appropriate to propose 30-day averages in order to provide a means for the source operator to account for that variability by applying a long term average for establishing compliance.”*

For Boilers already equipped with CO CEMS or operators who elect to use the more restrictive CO CEMs to monitor combustion performance on their boilers, the operator should also be afforded at least a 30-day averaging period for monitoring CO emissions. The 10-day average currently proposed in the rule for CO compliance is, for the very reasons cited by EPA above, grossly insufficient to account for operating swings and variability that are inherent in industrial boilers.

Response: The EPA agrees that a 30-day rolling average better accounts for the inherent variability and operating swings in industrial boilers. We have revised the rolling average times for the CO CEMS-based limits in the final rule to be based on a 30-day rolling average, where data are available. For some subcategories, not enough data were reported to be able to calculate a 99 percent UPL based on a 30-day rolling average. For these subcategories, a 10-day rolling average was used.

Commenter Name: Dakota Gasification Company Great Plains Synfuels Plant

Commenter Affiliation: David W. Peightal

Document Control Number: EPA-HQ-OAR-2002-0058-3424

Comment Excerpt Number: 12

Comment: EPA should also consider a 30-day rolling emissions limit for the CO CEMS based limit for consistency.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 32.

Commenter Name: Randall D. Quintrell
Commenter Affiliation: Georgia Paper & Forest Products Association
Document Control Number: EPA-HQ-OAR-2002-0058-3451-A1
Comment Excerpt Number: 10

Comment: The averaging period should be lengthened to 30 days.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 32.

Commenter Name: John S Williams
Commenter Affiliation: Maine Pulp & Paper Association (MPPA)
Document Control Number: EPA-HQ-OAR-2002-0058-3466-A1
Comment Excerpt Number: 12

Comment: EPA should retain a 30~day rolling average basis for compliance with CO limits. In the March 21,2011 Boiler MACT regulation, EPA included CO emissions limits based on 30-day rolling averages and operation of a continuous emission monitor system (CEMS) for boilers 100 MMBtu/hr and greater. The December 23, 2011 proposed amendments would shorten the averaging time for CO to a 10-day rolling average basis. Boiler MACT rule establishes CO limits with compliance based on stack tests, which does not provide time to average out inevitable swings in operation and resulting variable CO emissions. EPA also made changes to its methodology for establishing the final CO limits as compared to the methods used to establish the proposed limits. EPA should reconsider the CO limits because MPPA, its members and the Maine DEP could not reasonably discern at the time of proposal the way in which EPA would develop the limits and require compliance with the final standard and therefore did not have a meaningful opportunity to comment on these issues. MPPA members are aware that NCASI has extensively reviewed the methodology used by EPA in the development of the long term CO limit and finds that the data is auto correlated. When the data is assessed using a longer averaging period a higher CO limit is justified. We understand they will be providing recommendations and urge EPA to adopt this more scientifically based approach.

MPPA strongly urges that EPA either return to a 30-day rolling average for CO limits from biomass boilers equipped with CO continuous emissions monitors and establish more appropriate CO limits for wet biomass fuel boilers.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 32.

Commenter Name: Heather Parent
Commenter Affiliation: Maine Department of Environmental Protection
Document Control Number: EPA-HQ-OAR-2002-0058-3691-A2
Comment Excerpt Number: 7

Comment: Existing units operating in Maine that currently utilize continuous emission monitoring systems to demonstrate compliance with licensed carbon monoxide (CO) emission limits do so over 30- day rolling average time periods. Maine DEP recommends EPA apply a 30-

day averaging period consistent with averaging periods for nitrogen oxides and sulfur dioxide in other EPA boiler rules.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 32.

Commenter Name: M.L. Steele

Commenter Affiliation: CraftMaster Manufacturing, Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3814-A1

Comment Excerpt Number: 15

Comment: We request that compliance with the CO CEM's limits be on a 30-day averaging period to be consistent with existing programs.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 32.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 71

Comment: Even with this approach, however, EPA should further consider that the available CO CEMS data in some cases were for short periods of time (e.g., 30 day tests required by EPA under CAA § 114 authority). Therefore, simply due to that limited time period, the boilers tested did not experience the full range of operational variations that would likely impact CO emissions and would occur over a longer time period, such as at least one year, where variables such as unit operating condition, seasonal steam demand, and fuel quality would pass through all seasons of the year. Thus, for those cases utilizing short term data, the floor setting methodology should provide further latitude to account for undocumented and undemonstrated inherent variability that would be seen by even the best performing units.

Response: The EPA is required by the Clean Air Act to establish MACT floor levels based on emissions information available to the Administrator. Additional data submissions were requested in the preamble to the proposed rule, but only limited additional data were received during the comment period. The methodology used to establish the alternative CO CEMS-based limits has been revised to more fully account for the operational variability within the averaging time length. For more information on the revised methodology, please see the memo entitled, "CO CEMS MACT Floor Analysis (August 2012) for the Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP" in the docket. See also response to comment EPA-HQ-OAR-2002-0058-3520-A1, excerpt 14. This excerpt may be found in the CO CEMS "Methodology: Statistical Analysis" section of this comment response document.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 83

Comment: EPA has proposed alternate CO CEMS-based limits for solid fuel boiler subcategories based on a limited amount of data, and is proposing a 10-day averaging period. We are aware of additional data that are being submitted by member companies and analyzed in NCASI's comments on the proposed rule. For many subcategories, there will be adequate data available for EPA to propose longer averaging times. As emissions of CO can be highly variable, as described in other sections of these comments, EPA should establish the longest averaging period that can be justified by the available data.

Response: We agree with the commenter. Any additional CEMS data provided during the comment period have been incorporated into the EPA ICR Databases, so long as the data were reported in a suitable format. The EPA has increased the averaging time for the alternative CO CEMS-based limits to a 30-day rolling average for the subcategories where the switch was justified by available data.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 83

Comment: EPA is currently proposing a 10-day averaging period. CIBO is aware that additional data will be submitted and that EPA will be justified in proposing longer averaging times. It would be appropriate for EPA to establish the longest averaging period that can be justified by the available data.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 83.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 84

Comment: EPA should specify how a 10-day rolling average for the CO CEMS limit is calculated, indicating that it includes the previous 240 hours of valid operating data. EPA should make clear that valid data excludes hours during startup and shutdown as well as unit down time. This clarification will be helpful in implementation, as some permitting authorities have interpreted how compliance is demonstrated with rolling averages in odd and sometimes unintended ways. For example, when a unit is down for an outage exceeding the rolling average period (10 days in this case) state regulators have sometimes sought to continue the 10-day calculation through the outage, ultimately basing the final rolling average on one sole CO reading – the final valid hourly reading before shutdown. As this value is likely to be higher than typical due to initiation of shutdown during that hour, this final 10-day average calculation would likely exceed the 10-day limit. We believe that such interpretation would be outside EPA's intention in setting the standard. Specification of the minimum number of readings ensures that the 10-day average concept is not undermined in cases of long outages.

Response: We agree that the rolling average period should include all valid hourly CO CEMS data points collected during the averaging period, and that these should exclude data points

pertaining to periods of startup and shutdown. Periods of startup and shutdown are not subject to the alternative CO CEMS-base emission limits, and are instead subject to a work practice standard. Where justified by available CEMS data, we have changed the averaging time to a 30-day rolling average for the alternative CO CEMS-based emission limits. The definitions of the rolling averaging times in the final rule have been revised to pertain to the arithmetic average of all hourly data, excluding periods of startup and shutdown, from the duration of the averaging time.

Commenter Name: Richard D. Garber

Commenter Affiliation: Boise Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3686-A2

Comment Excerpt Number: 3

Comment: We support inclusion of an alternative CO compliance standard, a 10-day averaging period, for biomass units equipped with CO CEMS for compliance demonstration. While Boise would urge EPA to re-evaluate the available CO CEMS data and move to adopt a longer averaging period and a higher emission limit (discussed further in our letter), we do want to acknowledge EPA's efforts to date for including this approach for units that have CEMs already installed, and for which the three-hour stack test compliance demonstration was unworkable.

Response: The EPA thanks the commenter for their support of an alternative CO CEMS standard. For response to allowing longer averaging times, please see response to comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 83.

Commenter Name: Kevin G. Desharnais, Attorney, Mayer Brown LLP

Commenter Affiliation: United States Sugar Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3496-A1

Comment Excerpt Number: 7

Comment: The CO CEMS-based compliance limit is intended to provide a reasonable compliance alternative for sources that have an existing CO CEMS unit. As EPA notes in the Reconsideration Proposal, various petitioners have pointed out that, "given the highly variable nature of CO emissions, an emission limit based on CO CEMS data from boilers over time would more adequately capture the true variability in CO emissions over various operating conditions." Reconsideration Proposal, 76 Fed. Reg. at 80611. EPA therefore calculated a CO CEMS-based MACT floor for each subcategory for which data were available. Unfortunately, the proposal then falls flat by establishing a 10-day rolling average compliance period. This averaging period is simply insufficient to account for the variability in CO emissions under a real-world range of operating conditions.

Response: The EPA has increased the averaging time to a 30-day rolling average for the subcategories where the switch was justified by available data. For a response to the request for a 12-month rolling average to account for high variability in bagasse-fired boilers, see response to comment EPA-HQ-OAR-2002-0058-3504-A1, excerpt 31. This excerpt may be found in the CO CEMS "Existing Results: Biomass Suspension/Grate" section of this comment response document.

Commenter Name: David A. Buff, Golder Associates Inc.
Commenter Affiliation: Florida Sugar Industry (FSI)
Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1
Comment Excerpt Number: 38

Comment: EPA should clarify that the 12-month rolling average should include all valid hourly data recorded during the previous 12 months of operation (as opposed to using daily averages over the preceding 365 days). This approach will ensure that each hour of operation is given the same weight in the averaging.

Response: For discussion on what constitutes valid hourly data, please see the response to comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 84.

For a response to the request for a 12-month rolling average to account for high variability in bagasse-fired boilers, see response to comment EPA-HQ-OAR-2002-0058-3504-A1, excerpt 31. This excerpt may be found in the CO CEMS “Existing Results: Biomass Suspension/Grate” section of this comment response document.

Commenter Name: Kevin G. Desharnais, Attorney, Mayer Brown LLP
Commenter Affiliation: United States Sugar Corporation
Document Control Number: EPA-HQ-OAR-2002-0058-3496-A1
Comment Excerpt Number: 6

Comment: As an alternative to CO stack testing and oxygen monitoring, the Reconsideration Proposal also includes CO CEMS-based limits. EPA has proposed a 1 O-day rolling average for determining compliance with these limits. This overly short averaging period undercuts the usefulness of this provision, rendering it unworkable, and US Sugar objects to the 10-day averaging period, particularly as applied to bagasse boilers.

Response: For a response to comments suggesting a 10-day rolling average is insufficient to capture natural variation in CO emissions from bagasse-fired boilers, see response to comment EPA-HQ-OAR-2002-0058-3496-A1, excerpt 7.

Commenter Name: Kevin G. Desharnais, Attorney, Mayer Brown LLP
Commenter Affiliation: United States Sugar Corporation
Document Control Number: EPA-HQ-OAR-2002-0058-3496-A1
Comment Excerpt Number: 8

Comment: Elsewhere in the proposal, EPA generally extends the time periods for parameter monitoring and demonstration of continuous compliance with operating limits from a 12-hour period to a 30-day rolling average. In support of this change, EPA states, "Concerns of variability outside the operators control such as fuel content, seasonal factors, load cycling and infrequent hours of needed operation prompted us to look at longer averaging periods on which to base operating compliance determination." 76 Fed. Reg. at 80610. These considerations are equally applicable to CO emissions. In the case of bagasse boilers, the potential variation is compounded by the natural variation in the fuel source, which can be affected by differences in

crop conditions, plant varieties, and weather conditions. The proposed ten-day rolling average is simply insufficient to capture the natural variation in CO emissions from bagasse boilers.

Response: For the reasons provided in the preamble to the December 2011 proposed rule, EPA has elected to extend averaging times for parametric monitoring to a 30-day rolling average. These averaging times may be different than the averaging period for some of the alternative CO CEMS-based emission limits. This is because the CEMS-based limits were calculated based on the longest averaging period allowed by available data, up to a 30-day rolling average.

For a response to comments suggesting a 10-day rolling average is insufficient to capture natural variation in CO emissions from bagasse-fired boilers, see response to comment EPA-HQ-OAR-2002-0058-3496-A1, excerpt 7.

Commenter Name: Robert Cleaves

Commenter Affiliation: Biomass Power Association (BPA) and California Biomass Energy Alliance (CBEA)

Document Control Number: EPA-HQ-OAR-2002-0058-3489-A1

Comment Excerpt Number: 2

Comment: BPA supports the alternative 10-day rolling average CO standard and the 30-day average monitoring provisions. However, there have been problems implementing rolling average standards which EPA should address. EPA should specify how the 10-day rolling average is calculated, indicating that each 10-day average includes the previous 240 hours of valid emission data. Similarly, each 30-day rolling average should be calculated using the previous 720 hours of valid data. Valid data excludes hours during startup and shutdown (when work practices apply) as well as unit down time. We believe this will be helpful in implementation, where States have looked at rolling averages in odd and sometimes unintended ways. For example, when a unit is down for an outage exceeding the rolling average period (10 days in the case of the CEMS-based CO standard) State regulators have sought to base the final rolling average solely on one CO reading - the final valid hourly reading before shutdown. Since this value is likely to be higher than typical due to initiation of shutdown during that hour, this final 10-day ave_age calculation would be more likely to exceed the 10-day limit. We believe that such interpretation would be outside EPA intention in setting the standard. The specified number of readings assures that the 10-day average concept is not undermined in cases of long outages.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 84.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 84

Comment: Based on the information contained in the 2011 Reconsidered BMACT Rule, it is not clear how the 10-day rolling average for the CO CEMS limit is calculated. EPA needs to clarify that valid data excludes hours during startup and shutdown and unit down time. EPA

should specify the minimum number of readings, which will assure that the 10-day average concept is not undermined in cases of long outages.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 84.

Commenter Name: Monica Lopes

Commenter Affiliation: NAES Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3808-A1

Comment Excerpt Number: 5

Comment: Under 40CFR63.7575, EPA defines 30-day rolling average as “the arithmetic mean of all valid data from 30 successive operating days that is calculated for each operating day using the data from that operating day and the previous 29 operating days”. Please clarify if there is a minimum number of valid data points that need to be collected each operating day based on the number of hours the unit operated each day before the data is used to calculate the 30-operating day rolling average.

Response: For an explanation on how the definition of 30-day rolling average has been revised in the final rule, please see response to comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 84. Section 63.7525 of the final rule specifies the minimum data collection requirement when operating continuous emission or parameter monitoring systems. That is a minimum of 4 CO CEMS data values to have a valid hour of data.

Commenter Name: Monica Lopes

Commenter Affiliation: NAES Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3808-A1

Comment Excerpt Number: 6

Comment: Please clarify if units that operate intermittently should use the valid data points from their previous 29 operating days even if these operating days may be spaced throughout a three month or greater period.

Response: For an explanation on how the definition of 30-day rolling average has been revised in the final rule, please see response to comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 84. Units which operate intermittently should not include data points from periods of startup, shutdown, or when the unit is not operating. The averaging time corresponds to the previous 720 hours in which operations were not interrupted, even though valid emissions data may be limited for the time period for units which are operated intermittently. The 720 hour period may span a period greater than 30 calendar days if operations were intermittent.

Commenter Name: Rick Rosvold

Commenter Affiliation: Xcel Energy Services, Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3682-A2

Comment Excerpt Number: 3

Comment: It has also been our experience that a longer CO averaging period is more appropriate than a 10-day rolling average for a wet biomass stoker boiler in order to account for

the intricacies in burning this type of fuel. Biomass combustion is negatively impacted by a number of factors, including weather, harvest conditions and fuel variability. Weather impacts the fuel negatively through precipitation. Wetter fuel makes for more difficult combustion control. Harvest conditions play a role as well in that more green wood deliveries over an averaging period leads to higher CO emissions over that time frame. Finally, fuel variability issues also impact CO emissions. Fuel is supplied to our facility by multiple sources from multiple locations. Each of these fuels behaves differently due to its source and delivered condition. Since we have limited control of the delivered condition of each of these fuels, we need flexibility to meet the CO limits through a longer averaging period.

Response: The EPA recognizes the inherent variability of biomass fuels. EPA believes that the statistical procedures used to derive the alternative CO CEMS-based limits for Stoker/Sloped Grate/Other units designed to burn wet biomass, namely a 99% UPL and a 30-day averaging period, account for the inherent variability of the biomass fuel.

For response to request for longer averaging times for biomass-fired boilers, see response to comment EPA-HQ-OAR-2002-0058-3505-A1, excerpts 27, 28, 30, 31, 32, 33, and 37. These excerpts may be found in the CO CEMS “Alternative MACT Floor Using Highest Rolling Average” section of this comment response document.

4F. Alternative MACT Floor Using Highest Rolling Average

Commenter Name: Ashok K. Jain

Commenter Affiliation: National Council for Air and Stream Improvement, Inc. (NCASI)

Document Control Number: EPA-HQ-OAR-2002-0058-3505-A1

Comment Excerpt Number: 29

Comment: To address this dilemma where a significant fraction of the data in the best performing data sets exceed the estimated UPL-based limits, often well over and above what the confidence limits (99.0% or 99.9%) would have indicated, EPA proposed an “Alternate MACT Floor Calculation Methodology.” After the maximum 10-day rolling average was determined for each unit, the highest maximum 10-day rolling average from the top half of the best performers for each subcategory was selected as a MACT floor option. EPA reasoned that “In the CEMS-based compliance alternative, it is necessary for MACT floors to be achieved by the best performers at all times, even during large CO swings; the maximum rolling average value from the top half of the best performers is chosen to represent the performance of the average emission limitation achieved by the best performing 12 percent of existing sources (for which emission information is available).” Further, EPA noted that “since only one unit’s maximum rolling average is used for this option, the unit’s operation must be representative of the entire subcategory. Therefore, the unit selected must be firing a fuel which is reasonable to obtain for the entire subcategory and not process specific nor based on co-fired configurations.”

NCASI is in agreement with this alternate approach forwarded by EPA. This would essentially eliminate the possibility of a boiler in the best performing floor itself being in violation of the CEM-based limit. Based on this alternate methodology, a 919 ppm limit was determined for wet biomass stokers (rounded to 920 ppm), which corresponded to the maximum 10-day RA for the CASierraPacificLincoln biomass stoker unit. Similarly, a 478 ppm limit was determined for

biomass FBCs (rounded to 480 ppm), which corresponded to the maximum 10-day RA for the GATempleInland Rome biomass FBC unit.

Response: The EPA thanks the commenter for their support. For the alternative CO CEMS-based limits in the final rule, EPA considered the emissions of the top 6 percent for each subcategory. The maximum rolling average of the top 6 percent of the subcategory was selected as the basis of the CEMS-based limit if it was larger than the calculated 99% UPL for the same subcategory. For additional information, please see the memo titled, “CO CEMS MACT Floor Analysis (August 2012) for the Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants – Major Source” in the docket.

Commenter Name: Ashok K. Jain

Commenter Affiliation: National Council for Air and Stream Improvement, Inc. (NCASI)

Document Control Number: EPA-HQ-OAR-2002-0058-3505-A1

Comment Excerpt Number: 27, 28, 30, 31, 32, 33, 37

Comment: There were 2224 daily averages considered for the 4 best performing boilers in the biomass stoker category (1468 for CASierraPacificLincoln, 500 for WABoisePaperWallula, 30 for MNDESPHansONyman, and 226 for MSGPNewAugusta). Only days when >90% biomass was fired were considered. Similarly, there were 866 daily averages considered for the 3 best performing boilers representing the biomass FBC category (30 for ORGeorgiaPacific Wauna Mill, 185 for ALIPCourtland and 651 for GATempleInlandRome).

The 99% UPL was estimated using the equation:

$$\text{UPL} = \bar{x} + t(0.99, n - 1) \times \text{sqrt}(s^2 \times (1/n + 1/m)) \text{ [Equation 1]}$$

The t-statistic was calculated using the following Excel equation:

$$\text{t-statistic} = \text{TINV}(2*(1-0.99),n-1) \text{ [Equation 2]}$$

where:

n = the number of daily averages in the best performing 12 percent

m = the number of daily averages in the compliance average; m = 10 for all subcategories based on 10-day rolling averages;

s = the standard deviation of the daily averages in the best performing 12 percent

\bar{x} = the sample mean of test runs from top performing units

For datasets that were determined to be lognormally distributed (generally the case for most data sets), the UPL (log normal) was equal to the exponential of the UPL estimated using eqn. 1 but with \bar{x} and s^2 referring to the data in the log normal space.

As mentioned above, a 99% UPL-based 10-day rolling average limit of 410 ppm @3% O₂ was estimated from analysis of the daily averages for the four biomass stokers (rounded up from 405 ppm). It should be noted that unlike assigning UPL-based limits to short duration tests conducted

on a boiler, assigning a UPL-based limit to boilers equipped with continuous monitors would always result in a conflict. For example, under Boiler MACT, by definition a 99% UPL-based limit implies that ~1% of the data in the “best performer” data set is expected to exceed this value. This would therefore imply that boilers with CO CEMs should be allowed a 1% exceedance or about 4 exceedances per year. In the current situation with biomass stokers, this problem is further exacerbated. As shown in Figure 1 [See submittal for Figure 1], which is a graphical display of all the 10-day rolling averages used to determine the 99% UPL value for biomass stokers, ~18% of the 10-day RAs would exceed the 99% UPL-based limit of 410 ppm. If a 99.9% UPL value were estimated (as was the case with the short term stack test data), the UPL value would have been ~466 ppm, and about 11.5% of the data in the best performer set would exceed this limit. As shown below, this is caused by severe autocorrelation that exists in these and likely all CEM-based hourly average and even 10-day rolling average data.

A similar trend can be seen with the treatment of data for the three biomass FBC units. A 99% UPL 10- day rolling average of 180 ppm @3% O₂ was estimated from the data for these units (rounded up from 177 ppm), which meant that 16.2% of the 10-d RAs would exceed this level. Once again, this is demonstrated by the graphical display of the data in Figure 2. [See submittal for Figure 2] If a 99.9% UPL were used, the 10-day rolling average value would have been ~208 ppm, and about 9.4% of the data in the best performer set would exceed this level.

The key reason why a 99.0% UPL or even a 99.9% UPL calculated as above results in a significant fraction of the data in the best performing floor itself to exceed the limit (well beyond the expected 1.0% or 0.1% of the time) can be traced to the fact that $m = 10$ was used in equation 1. In other words, EPA assumed that 10 consecutive daily averages in the current data set are independent data points with no auto-correlation. If this were the case, the standard deviation (SD) of the original “best performer” data set consisting of single daily averages when compared with the SD of the same data set but with 10-day (consecutive) block averages should be reduced by 68.4% ($1 - 1/\sqrt{10}$). Instead, for biomass stokers, the SD drops by only about 19.3%, and for biomass FBCs it drops by 31.3%, both of which suggest the data are highly auto-correlated and using $m = 10$ would lead to erroneous results.

Thus, if the UPL approach is to be used, the UPLs should be calculated using $m = 1$, with each data point constituting a 10-day (consecutive) block average. The 99.0% and 99.9% UPLs for the 4 best performing biomass stokers calculated using $m = 1$ and $n = 222$ (10-d block averages) are estimated at ~730 and 1010 ppm, respectively. For these UPL values, nearly 1.5% and 0.0% of the data in the best performer data set would exceed the corresponding limits, respectively. Similarly, the 99.0% and 99.9% UPLs for the 3 best performing biomass FBC units calculated using $m = 1$ and $n = 87$ (10-d block averages) are estimated at ~410 and 630 ppm, respectively, and for these UPL values, nearly 0.7% and 0% of the data in the best performer data set would exceed the corresponding limits, respectively.

From a biomass boiler operational point of view, CO limits based on a monthly rolling average would be more appropriate than limits based on daily, weekly or 10-day averages considering normal variations in fuel quality and fluctuating loads. Unfortunately, the majority of the biomass stokers (10 of 14) considered by EPA had only 30 to 60 days of CEM CO data. Thus, a monthly average would be difficult to estimate from these data. However, the same daily average CEM data for 14 biomass stokers and 3 biomass FBCs used to calculate the 10-day RA limits could be used to generate 15-day RA limits (a compromise). The following provides a look at

how the various limits described above would look like if a 15-day rolling average were used instead of a 10-day RA. It should be noted that additional data may become available to EPA both from the forest products industry's own testing and from other sources.

The same four boilers that represented the best performers for biomass stokers when using 10 day RAs are seen to be the best performers when using 15-day RAs. Using $m = 15$ (i.e. ignoring auto-correlation), a 99% UPL 15-day rolling average value of 374 ppm @3% O₂ is estimated from the daily average data for the four best performing biomass stokers, and ~23% of the 15-day RAs are seen to exceed this limit. Using $m = 15$, a 99.9% UPL monthly RA value of ~420 ppm is estimated, and nearly 16% of the data in the best performer set would exceed this limit.

The same three boilers that represented the best performers for biomass FBCs when using 10 day RAs are also determined to be the best performers when using 15-day RAs. Using $m = 15$, a 99% UPL 15-day rolling average value of 162 ppm @3% O₂ is estimated from the daily average data for the three biomass FBCs, with ~24% of the monthly RAs exceeding this limit. Using $m = 15$, a 99.9% UPL 15-day RA value of ~185 ppm is estimated, with about 15% of the data in the best performer set exceeding this limit. As with the 10-day averages, if the UPL approach is to be used, the UPLs should be calculated using $m = 1$, with each data point constituting a 15-day (consecutive) block average. The 99.0% and 99.9% UPLs for the 4 best performing biomass stokers calculated using $m = 1$ and $n = 147$ (15-d block averages) are estimated at ~720 and 980 ppm, respectively. For these UPL values, nearly 1.6% and 0.0% of the data in the best performer data set would exceed the corresponding limits, respectively. Similarly, the 99.0% and 99.9% UPLs for the 3 best performing biomass FBC units calculated using $m = 1$ and $n = 57$ (15-d block averages) are estimated at ~410 and 630 ppm, respectively, and for these UPL values, 0.0% of the data in the best performer data set would exceed the corresponding limits.

Once again, using $m = 15$ is shown to lead to the use of highly auto-correlated data in the case of both the biomass stokers and biomass FBCs, and thus erroneous results. While the SD of the original "best performer" data set when compared with the SD of the same data set but with 15-day (consecutive) block averages should be reduced by 74.2% ($1 - 1/\sqrt{15}$), for biomass stokers, it drops by only 20.5%, and for biomass FBCs, it drops by only 30.1%. Based on the alternate methodology proposed by EPA, where the maximum 15-day rolling average would be used as the limit, a 860 ppm limit (rounded up from 856 ppm) corresponding to the maximum 15-day RA for the CASierraPacificLincoln biomass stoker unit and a 400 ppm limit (rounded up from 398 ppm) corresponding to the maximum 15-day RA for the GATemple Inland Rome biomass FBC unit are determined to be the MACT floors for biomass stokers and biomass FBCs, respectively.

CEM CO emissions data for any industrial boiler are expected to be highly correlated even when compared on a daily average basis. The daily average CEM CO data in EPA's current database are no exception. Using $m = 10$ in the UPL equation used to calculate the 10-day rolling average limit assumes that 10 consecutive daily averages are independent data points. This assumption leads to limits that are exceeded by a significant fraction of the 10-day rolling averages recorded by the "best performing" units. This is unreasonable.

Based on the analysis presented above, we conclude that the alternate methodology offered by EPA, whereby the highest maximum rolling average from the top half of the best performers for each subcategory would be selected as the MACT floor, is the best option. This option would

also fulfill a necessary condition that significant fractions of the data used to set the floor cannot exceed the floor itself.

Using the alternate option, a 10-day rolling average limit of 920 ppm and 480 ppm at 3% O₂ is estimated for wet biomass stokers and biomass FBCs, respectively.

Despite the reservations expressed in this document, if EPA decides to pursue a 10-day average UPL-based approach, then it is recommended that 10 day block averages and $m = 1$ be used in the UPL equation instead of daily averages and $m = 10$. This approach is needed to address the autocorrelation issue in the datasets. For wet biomass stokers, this would result in 99.0% and 99.9% UPL values of 730 and 1010 ppm at 3% O₂, respectively. Similarly, using this approach, 99.0% and 99.9% UPL values of 410 and 630 ppm at 3% O₂, respectively, are estimated for biomass FBCs. If the 99.0% UPLs are chosen, then a 1% exceedance or 4 days/year should also be incorporated with the limit.

Since averages of longer time periods are desirable from a biomass boiler operational point of view, 15-day rolling averages should be considered in lieu of 10-day RAs.

Using the alternate option, a 15-day rolling average limit of 860 ppm and 400 ppm at 3% O₂ is estimated for wet biomass stokers and biomass FBCs, respectively.

If a UPL-based approach with $m = 1$ and 15-day block averages is used in the UPL equation, for wet biomass stokers, this would result in 99.0% and 99.9% UPL values of 720 and 980 ppm at 3% O₂, respectively. Similarly, using this approach, the 99.0% and 99.9% UPL values of 410 and 630 ppm at 3% O₂, respectively, estimated using 10-day averages for biomass FBCs remain unchanged. Again, if the 99.0% UPLs are chosen, then a 1% exceedance or 4 days/year should also be incorporated with the limit.

NCASI believes that EPA's alternate methodology that reasons "it is necessary for MACT floors to be achieved by the best performers at all times, even during large CO swings" is a sound one and should be used to set the floors for biomass stoker and FBC units equipped with CO CEMs.

The table below summarizes CO CEMS-based limits for solid fuel boilers if the UPL-based approach or the alternate approach suggested by EPA of using the maximum 10-day rolling average were to be adopted. As previously noted, EPA should consider using 15-day rolling averages to accommodate the inherent variability in biomass boiler CO emissions resulting from fluctuations in fuel quality and steam demand. [See submittal for Table]

Response: The EPA thanks the commenter for their support of the alternative CO CEMS MACT Floor calculation methodology. For response to the issue on data used in floor calculations not exceeding the floor itself, see response to comment EPA-HQ-OAR-2002-0058-3505-A1, excerpt 29.

We have revised the methodology used to calculate the CO CEMS UPL. Where justified by available CEMS data, we have switched to a 30-day rolling average. EPA evaluated the commenter's provided UPL calculations based on a 15-day rolling average. However, EPA made the decision to employ a 30-day rolling average where allowed by available data. A 15-day rolling average may experience the same issues with operational variability that would be experienced with a 10-day rolling average, but those concerns are greatly mitigated with a 30-

day averaging period. The UPL is also computed from all available CEMS data points from valid periods of operation (excluding periods of startup and shutdown) that comprise the 10-day or 30-day rolling average. For additional discussion on what constitutes valid operational periods for compliance with CO CEMS-based limits, see the response for comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 84. This excerpt may be found in the CO CEMS "Averaging Time and Rolling Average Length" section of this comment response document. For more information on the revised methodology, please see the memo titled, "CO CEMS MACT Floor Analysis (August 2012) for the Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP" in the docket. The EPA agrees that the UPL calculation should be revised to account for autocorrelation. In the calculation of the UPL, "m" has been assigned a value of 1 for the reasons specified by the commenter. However, a 99 percent confidence interval has been maintained with the UPL calculation in lieu of the 99.9 percent confidence interval suggested by the commenter. For the reasons identified in the preamble to the December 23, 2011 proposed rule, the EPA believes that the 99% UPL properly accounts for the variability in CO emissions.

We agree that the averaging times should be increased in order to more fully account for the inherent variability of CO emissions and operating load changes, particularly for units combusting biomass or bio-based solid fuels. Where justifiable from available CEMS data, we have increased the averaging time to a 30-day rolling average for the alternative CO CEMS-based emission limits. Statistical variability was calculated using a 99 percent UPL. The alternative CO CEMS-based limits were based on this calculated UPL or the maximum rolling average of the best emitting 6 percent of units in the subcategory, whichever value was greater. We believe this revised methodology and the switch to 30-day averaging periods for certain subcategories allows sources greater flexibility in operational load swings and the inherent variability of CO emissions.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 82

Comment: EPA has proposed an "Alternate MACT Floor Calculation Methodology" where the highest maximum 10-day rolling average from the top half of the best performers for each subcategory was selected as a MACT floor option. Setting an alternative standard for data collected using CEMS is necessary because MACT floors must be "achieved by the best performers at all times, even during large CO swings." EPA's current approach would eliminate the possibility of a boiler in the best performing floor being in violation of the CEMS-based limit. Nothing in the CAA prohibits EPA from establishing alternative requirements for data gathered using CEMS. In fact, CAA § 112(d) provides EPA with broad authority to "distinguish among classes, types, and sizes of sources within a category or subcategory in establishing such standards." Boilers with CEMS are easily distinguishable from those that do not have CEMS.

Response: For a response on EPA's actions on considering a maximum rolling average for the top 6 percent in the final rule, please see response to EPA-HQ-OAR-2002-0058-3505-A1, excerpt 29.

Commenter Name: Lorraine Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1
Comment Excerpt Number: 70

Comment: *EPA Should Use an Alternate CO CEMS MACT Floor Calculation Methodology*

The short term CO limits based on stack test data were developed from limited data sets and the stack test data were obtained at steady state, high load conditions. CO emissions will change as operational conditions within the boiler change, so complying with a stack test based CO limit using a CO CEMS would likely prove impossible. Therefore, EPA has proposed CO CEMS-based limits to more adequately capture the variability of CO emissions over various operating conditions. EPA has proposed 10-day average CO limits for units that have CEMS and has calculated the MACT floors for units with CO CEMS using much the same approach as the MACT floor calculation for units with stack test data.

In this Reconsideration Proposal, EPA considered an alternate method for determining CO CEMS floors that would adjust the CO CEMS-based emission limits to reflect the actual level that was demonstrated to be achieved at all times by those units. (76 Fed. Reg. 80613.) ACC agrees with EPA's alternate approach. This approach would essentially eliminate the possibility of a boiler in the best performing floor itself being in violation of the CEMS-based limit.

Response: The EPA thanks the commenter for their support.

Commenter Name: Paul Noe
Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.
Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1
Comment Excerpt Number: 82

Comment: In order to avoid the situation described on preamble page 80613, where a significant fraction of the CEMS data in the best performing data sets are seen to exceed the estimated UPL-based limits, often well over and above what the confidence limits (99.0% or 99.9%) would have indicated, EPA proposed an "Alternate MACT Floor Calculation Methodology." After the maximum 10-day rolling average was determined for each unit, the highest maximum 10-day rolling average from the top half of the best performers for each subcategory was selected as a MACT floor option. EPA reasoned that "In the CEMS-based compliance alternative, it is necessary for MACT floors to be achieved by the best performers at all times, even during large CO swings; the maximum rolling average value from the top half of the best performers is chosen to represent the performance of the average emission limitation achieved by the best performing 12 percent of existing sources (for which emission information is available)."

We are in agreement with this alternate approach proposed by EPA. This approach would essentially eliminate the possibility of a boiler in the best performing floor itself being in violation of the CEMS-based limit.

Response: The EPA thanks the commenter for their support.

Commenter Name: M.L. Steele
Commenter Affiliation: CraftMaster Manufacturing, Inc.
Document Control Number: EPA-HQ-OAR-2002-0058-3814-A1
Comment Excerpt Number: 10

Comment: CO CEMS MACT Limits for Suspension Burner and Wet Stoker biomass subcategories. Per Table 11 in the CO GEMS MACT Floor Analysis²¹, the best 6% of units in the Suspension Burner and Wet Stoker biomass subcategories *complied with the 99% UPLbased CO GEMS MACT limit less than 75% of the time*. Then it is clear that the 99% UPL-based limit is not reasonable. We believe the CO GEMS MACT limits should be as outlined in Section 7 of the report, Alternative MACT Floor Calculation Methodology. That is, the CO CEMS MACT limits should be equal to the maximum 10-day rolling average of the top 6% of units.

Response: The EPA thanks the commenter for their support.

4H01 - MACT Floor Existing Results - Coal FB

Commenter Name: Dell Majure
Commenter Affiliation: Kimberly-Clark Corp.
Document Control Number: EPA-HQ-OAR-2002-0058-3692-A2
Comment Excerpt Number: 2

Comment: The CO emission limit for CEMs for coal-fired FB boiler is 59 ppmv @ 3 % O₂ (10-day rolling average) is derived from CO values from a single boiler "IARoquetteAmerica" firing bituminous coal. This boiler does not have a FBHE and the coal it fires contains approximately 9 % ash content.

There is a fundamental difference between the reference unit and K-C's FBHE boiler. The Chester FBHE boiler cannot operate firing coal with only 9 % ash content because there is not enough ash too facilitate the conductive heat exchange with the furnace tubes and FBHE. By comparison, the design for the K-C FB boiler with its integral FBHE design requires a minimum fuel ash content of 20 – 25 %. This demonstrates a fundamentally different design than a coal-fired FB without a FBHE.

Therefore, the boiler used to establish the CO CEM emission limit is not of the same design or CO emission rates as a coal-fired FB boiler with a FBHE. In addition, the same is true for the CO stack test emission limit assuming that those boilers do not have a FBHE.

Response: The EPA agrees with the fundamental difference in design between the sources. A new subcategory has been added to the final rule for fluidized bed units with an integrated heat exchanger. Separate CO CEMS-based emission limitations have been established for traditional fluidized bed units and for fluidized bed units with an integrated heat exchanger.

Commenter Name: Dell Majure
Commenter Affiliation: Kimberly-Clark Corp.

Document Control Number: EPA-HQ-OAR-2002-0058-3692-A2

Comment Excerpt Number: 5

Comment: The K-C FB boiler with FBHE is designed to burn culm (high ash and moisture coal) mixed with other forms of coal (e.g. petroleum coke, bituminous, and anthracite). The mixture is 70 – 80 % culm and the balance is other forms of coal. K-C fires culm mixed with petroleum coke unless the local refineries shut down leaving no economically viable supply which has happened periodically. During these times other forms of coal are used in the culm mixture like bituminous.

K-C calculated the 99 % upper predictive limit for three different cases from the CO CEM values in the appendix [see submittal for appendix].

1. Culm and any fuel mixture fuel combination.
2. Culm mixture with petroleum coke.
3. Culm mixture without petroleum coke.

The results are show in the table [see submittal for table].

A concern that K-C has is that the emission limit for CO could be set at 84 ppmv for example reflecting the boiler perform on coal (i.e. all forms) and the refineries could shut down resulting in no economically viable supply of petroleum coke making it infeasible to achieve compliance.

Response: EPA has incorporated the provided CO CEMS data into the EPA ICR Databases, and the emissions data have been factored into the revised calculation of CO CEMS-based emission limits. For this rulemaking, emissions from the combustion of culm and petroleum coke are classified identically to emissions from coal combustion. As such, any mixture of coal and culm or petroleum coke was treated as 100% coal combustion in the development of the final rule. All CO CEMS data provided by the commenter were from the combined combustion of coal, culm, and/or petroleum coke, and thus all data were treated as 100% coal combustion and factored into the development of the alternative CO CEMS-based limits for the fluidized bed with integrated heat exchanger subcategory.

For a response to issues with FBHE boilers differing in design and having different emission and fuel profiles than the top performing emitter, please see response to comment EPA-HQ-OAR-2002-0058-3692-A2, excerpt 2.

4H02. Existing Results: Coal PC

Commenter Name: Nina Butler

Commenter Affiliation: Rock-Tenn Company

Document Control Number: EPA-HQ-OAR-2002-0058-3688-A2

Comment Excerpt Number: 2

Comment: The proposed CO emission limit for pulverized coal (PC) boilers with CO CEMs is 28 ppmv at 3% oxygen (dry basis) or, as an alternative, 35 ppmv at 3% oxygen (dry basis) based on the alternate approach forwarded by EPA where the maximum 10-day rolling average value is

selected, both based on just 60 days of data from one PC boiler. As described in the Coalition and NCASI comments, these levels are not achievable for most PC boilers on a continuous basis. A case in point is the No. 8 Power Boiler at RockTenn's West Point, Virginia pulp and paper mill.

The data set that EPA used to calculate the 28 or 35 ppmv CEMS-based limits for PC boilers was CEMS data from the No. 8 Power Boiler at RockTenn's West Point mill (Unit ID PB08 at Facility ID VASmurfitStoneWestpt in EPA's database). Although the West Point mill's No. 8 Power Boiler is the floor-setting unit, it would not meet the proposed CEMS-based CO limit on a continuous basis.

Response: We have revised the CO CEMS-based emission limit alternative for Pulverized Coal units in the final rule. Additional CEMS data from Pulverized Coal units were submitted to EPA and included in the calculation of the CEMS-based limit. The resultant limit is significantly less stringent than the limit in the December, 2011 proposed reconsideration of the rule and should mitigate any achievability concerns. Additional information on the calculation of CO CEMS-based limits may be found in the memo titled, "CO CEMS MACT Floor Analysis (August 2012) for the Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants – Major Source" in the docket.

Commenter Name: Ashok K. Jain

Commenter Affiliation: National Council for Air and Stream Improvement, Inc. (NCASI)

Document Control Number: EPA-HQ-OAR-2002-0058-3505-A1

Comment Excerpt Number: 35, 36

Comment: For PC-fired units, NCASI obtained 3 years duration of CO CEM data (2009, 2010 and 2011) from the VASmurfitStone Westpt unit that was used to calculate the 10-day rolling average floor of 28 ppm @3% O₂. Using the additional data, NCASI estimates the 99% UPL value would rise from 28 to 32 ppm @3% O₂, and the alternate limit rises from 35 to 67 ppm @3% O₂. As pointed out in the previous section 6a, the alternate limit based on determining the maximum 10-day rolling average in the data used to set the floor is much more defensible than a UPL-based limit.

There are several issues revolving around meeting a CEM-based limit of 67 ppm for pulverized coal units, the key issues being the inability to meet such a low limit during periods of low load operations and during transitions from high loads to low loads. For a boiler that is expected to fluctuate in its load capacity based on other factors that dictate the steam demand at a facility (such as in a paper mill where the steam demand will oscillate depending on the operational status of various steam-consuming unit processes), continuously meeting a 67 ppm limit is expected to be problematic. An option EPA should consider is to allow such boilers to meet the short-term based limit for PC boilers on an annual basis (same as for boilers with no CEMs), but not use the CO CEM data as a compliance assurance tool but rather as an indicator of such limits with appropriate surrogates (such as stack or boiler O₂) identified for corrective action.

Response: The EPA incorporated the additional CO CEMS data for the VASmurfitStoneWestpt boiler into the EPA ICR Databases and the data were considered in the revised calculation of the CO CEMS-based limit for the Pulverized Coal subcategory.

We disagree with the option to allow units to use CO CEMS data as only an indicator of limits with appropriate surrogates identified for corrective action. For discussion on compliance options for sources using a CO CEMS, please see the response to comment EPA-HQ-OAR-2002-0058-3257-A1, excerpt 6. We believe that the unit should demonstrate compliance with the limit at all times. We have revised the CO CEMS-based emission limit alternative for Pulverized Coal units in the final rule. The resultant limit is less stringent than the limit in the December, 2011 proposed reconsideration of the rule and should mitigate any achievability concerns.

Commenter Name: Samuel H. Bruntz

Commenter Affiliation: Alcoa Power Generating, Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3755-A1

Comment Excerpt Number: 11

Comment: Alcoa-Warrick is not aware of any pulverized coal boilers that were required to measure CO emissions using a CEMS when the Section 114 tests of 2009 were performed. Alcoa-Warrick thus encourages EPA to evaluate more CO test results from using a CO CEMS and using EPA Method 10, and to evaluate CO emissions from low NOx burners before finalizing the CO emission limits.

Response: The EPA is required by the Clean Air Act to establish MACT floor levels based on emissions information available to the Administrator. Additional data submissions were requested in the preamble to the proposed rule, but only limited additional data were received during the comment period. The methodology used to establish the alternative CO CEMS-based limits has been revised to more fully account for the operational variability within the averaging time length. For more information on the revised methodology, please see the memo entitled, "CO CEMS MACT Floor Analysis (August 2012) for the Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP" in the docket. See also response to comment EPA-HQ-OAR-2002-0058-3520-A1, excerpt 14. This excerpt may be found in the CO CEMS "Statistical Analysis" section of this comment response document.

We have revised the CO CEMS-based emission limit alternative for Pulverized Coal units in the final rule. The resultant limit is less stringent than the limit in the December, 2011 proposed reconsideration of the rule and should mitigate any achievability concerns.

4H05 - Existing Results: Biomass FB

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 47

Comment: Many biomass boiler operators will be able to utilize the stack test-based CO limits and associated 30-day average oxygen monitoring to comply. However, some of our members with top performing biomass fluidized bed boilers and biomass stoker units equipped with sophisticated combustion controls like over-fired air, cannot say with certainty that they will meet the proposed CO CEMS-based limits 100% of the time. CO emissions vary significantly

with changes in load and fuel quality to the point that some of the units on which EPA is relying to set the MACT floors cannot comply all year round.

The burning of wood or wood-derived fuels, by themselves or in combination with other fossil fuels, involves very different combustion conditions than fossil fuel. The same stringent limitations on CO emissions that apply to fossil fuel-fired boilers with good combustion practices are not relevant. The high moisture content typical of most wood-derived fuels necessitates a larger than usual area of refractory surface to dry the fuel before combustion. Sufficient secondary air must be supplied over the fuel bed to burn the volatiles that account for most of the combustible material in the fuel. However, the air should not be so excessive as to cool the combustion flame.

Wood residue is typically comprised of about 50% moisture and has a heat value of about 4500 Btu/lb (as fired), compared with typical heat values of about 12,000 Btu/lb for coal, 18,750 Btu/lb for oil and 24,000 Btu/lb for gas (as methane). Thus, wood residue has significantly lower heat value on a per pound basis than most fossil fuels. The lower heat value generally translates to lower adiabatic flame temperatures, which leads to lower efficiencies of combustion of the carbon content of wood. EPA's AP-42 emission factor document gives, for example, a range of 0.7 to 21 lb CO/ton wood residue, with an average of 6.6 lb/ton (or about 100 to 2900 ppm CO, average 900 ppm CO @3% O₂).

In an NCASI study,³⁴ detailed analysis of CO monitoring data corresponding to three wood-fired boilers representative of recent design and operated in a "normal" manner showed that average CO emissions ranged between 0.18 and 0.50 lb/106 Btu for a 150 hour monitoring period (about 225 to 625 ppm CO at 3% O₂). While a correlation between CO emissions and flue gas oxygen content was observed, high CO emissions resulted when either too little or too much excess air was used. A well-operated biomass boiler will have much higher CO emissions than most fossil fuel-fired boilers, even when optimally operated using good combustion practices.

[Footnote: "Carbon Monoxide Emissions from Selected Combustion Sources Based on Short-Term Monitoring Records," NCASI Technical Bulletin No. 416, January 1984.]

Response: We agree that CO emissions vary with changes in load and fuel quality. For discussion on variability of CO emissions, please see the response to comment EPA-HQ-OAR-2002-0058-3498-A1, excerpt 5. This excerpt may be found in the "CO CEMS as Alternative Standard" section of this comment response document. See also responses to comments EPA-HQ-OAR-2002-0058-3505-A1, excerpts 27, 28, 30, 31, 32, 33, and 37. These excerpts may be found in the CO CEMS "Alternative MACT Floor Using Highest Rolling Average" section of this comment response document. However, the emission limitations do not apply during periods of startup or shutdown, the periods that exhibit the largest magnitude of changes in load. We have also revised the CO CEMS-based emission limitation for Fluidized Bed units combusting biomass or bio-based solid fuels in the final rule. The resultant limit is less stringent than the limit in the December, 2011 proposed reconsideration of the rule. We believe that the exclusion of periods of startup and shutdown and the less stringent limit mitigates any achievability concerns.

4H06. Existing Results: Biomass Suspension Burner

Commenter Name: Mark Weiss

Commenter Affiliation: Reciprocal Energy Company

Document Control Number: EPA-HQ-OAR-2002-0058-3658-A2

Comment Excerpt Number: 3

Comment: The CEMS requirement is 24 times higher than the 3-hour test. These numbers should be similar. This discrepancy indicates a breakdown in the methodology.

Response: The EPA has revised both the CO CEMS-based and stack test-based emission limitations in the final rule. Both revised limits are less stringent than the limits in the December, 2011 proposed reconsideration of the rule, and the revised limits are similar in magnitude.

Commenter Name: Arthur N. Marin

Commenter Affiliation: Northeast States for Coordinated Air Use Management (NESCAUM)

Document Control Number: EPA-HQ-OAR-2002-0058-3506-A1

Comment Excerpt Number: 13

Comment: There are some subcategories where proposed carbon monoxide (CO) emissions limits using a 3-hour average measurement are more stringent than the alternative CO CEMS measurements using a 10-day rolling average (notably for biomass suspension burners). This disconnect is indicative of a situation where the subcategories have been parsed too finely and too few data points are available on which to base the standards at this refined level.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3658-A2, excerpt 3.

4H07 - Existing Results: Biomass Suspension/Grate

Commenter Name: David A. Buff, Golder Associates Inc.

Commenter Affiliation: Florida Sugar Industry (FSI)

Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1

Comment Excerpt Number: 31

Comment: The FSI believes that a 10-day rolling average for hybrid suspension grate boilers is not adequate to fully account for the variable nature of these boilers. Bagasse boilers are too highly variable, as discussed at length previously, because of fluctuations in steam load, crop conditions, cane varieties, weather conditions, mill fluctuations, etc., to comply with the proposed 10-day average limit for CO. Given the FSI's experience with the challenges of operating bagasse-fired boilers, the FSI believes the EPA's optional CEMS-based CO limits for hybrid suspension boilers should be based on an averaging time of at least 12 months. This request is supported by the CO data analysis presented below for hybrid suspension grate boilers.

Response: We agree that an averaging period longer than a 10-day rolling average would better account for the inherent variability of CO emissions and operational load swings in industrial boilers and process heaters. We have changed the averaging time for the alternative CO CEMS-based limits to be a 30-day rolling average where the switch was justified by available CEMS

data. We disagree that a 12-month rolling average is necessary for Hybrid Suspension Grate units. As mentioned in other rulemakings (e.g., MATS), we believe that a 30-day averaging period provides flexibility sufficient for sources to operate processes, in this case boilers and process heaters, and control devices to assure ongoing compliance and that the 30-day period provides for the level of environmental protection intended for this rule. The 30-day rolling average requires that the operator review and act on measurement data on at least a daily basis consistent with the enforcement and compliance provisions of the CAA (e.g., CAA section 113(d)). A rolling 12-month average would reduce that frequency to once per month. In addition, a 30-day rolling average is consistent with historical averaging times for this source category. For example, the new source performance standard, subpart Db for industrial, commercial, and institutional boilers in existence for over 25 years, uses 30 days for the rolling emissions averaging period.

Commenter Name: David A. Buff, Golder Associates Inc.

Commenter Affiliation: Florida Sugar Industry (FSI)

Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1

Comment Excerpt Number: 32, 33, 34, 35, 36, 37

Comment: The FSI previously provided EPA with several years of continuous hourly CO data for U.S. Sugar Company's Boiler No. 8, spanning the period October 2007 through March 2010. Boiler No. 8 is a new hybrid suspension grate boiler that was designed to comply with the 2004 Boiler MACT Rule for new sources. The FSI now is submitting additional CO CEMS data for Boiler No. 8, covering the period from March 2010 through December 2011, so that the entire database spans 2007 through 2011. The additional data are attached to this letter. Therefore, with this submittal, EPA will have a database that includes almost four years of operations, which should be more than adequate for EPA to establish a CO CEMS limit that is based on an averaging time of greater than 30 days. It is noted that these data do not include periods of malfunction, which are discussed separately below.

The FSI has analyzed the CO CEMS data for Boiler No. 8 by using the same methodology that EPA used when EPA set its proposed CO CEMS emission limits in the Proposed Boiler MACT Rule, with certain exceptions. EPA's methodology was based on an Upper Prediction Limit (UPL) utilizing a 99 percent confidence level (99% UPL). Because the MACT floor limit is being set based on CO CEMS data from Boiler No. 8, which is the "best performing source" for which EPA has data, a greater allowance should be provided in order to set the MACT floor for new sources. Therefore, FSI has used a 99.9% UPL. Using EPA's same methodology, with 99.9% UPL and the expanded data set, excluding malfunctions, produces the following new source CO limits for various averaging times:

30-day rolling average: 515 ppmvd @ 3% O₂

60-day rolling average: 481 ppmvd @ 3% O₂

90-day rolling average: 466 ppmvd @ 3% O₂

182-day rolling average: 448 ppmvd @ 3% O₂

365-day rolling average: 437 ppmvd @ 3% O₂

Attached is a graph of the rolling average CO concentration for Boiler No. 8 versus time for the 10-day, 30-day and 365-day rolling averages, excluding malfunctions [See submittal for Figure C-1]. This plot compares the boiler's actual performance against the proposed EPA limit of 730 ppmvd @ 3% O₂. As shown, a CO limit based on a 365-day rolling average is much less variable than a 10-day or 30-day rolling average. The data for Boiler No. 8 (the best performing source in the subcategory based on its age and design) demonstrate that the EPA's proposed 10-day rolling average limit would have been exceeded on 79 days over this approximate 4-year period, and even if the limit were based on a 30-day rolling average, 34 exceedances of the limit would have occurred. However, no exceedances of the proposed limit would have occurred based on a 365-day rolling average.

Comparing the graph of 365-day rolling averages to the 99.9% UPL calculations above shows the actual highest 365-day rolling average experienced by Boiler No. 8 was about 510 ppmvd @ 3% O₂. Therefore, the CO limit for new sources should not be set any lower than this value, and preferably would include some safety margin.

The CO CEMS data submitted to EPA for U.S. Sugar Company's Boiler No. 8 are the same data that are reported to the Florida Department of Environmental Protection under the Title V operating permit for Boiler No. 8. It is important to recognize, however, that the data do not include periods of time when the boiler experiences an upset condition (i.e., a malfunction). The exclusion of such periods of time is consistent with current law, which recognizes that malfunctions may occur due to a process upset or other conditions that are beyond the reasonable control of the operator. Upset conditions can occur due to a variety of reasons, including mill stoppages, plugged bagasse feeders in the boiler, bagasse piling up on the boiler grate, etc.

Under EPA's "affirmative defense" provisions in the Proposed Boiler MACT, these upset conditions will have to be included in the CO CEMS averages, because these events occur too frequently to qualify for the proposed affirmative defense for each event. Accordingly, the CO CEMS data for Boiler No. 8 were analyzed with data for the previously excluded events. The results of the additional analyses are also attached to this letter in Appendix C. [See submittal for Appendix C] Analyzing these data in accordance with EPA's methodology, and using the 99.9% UPL, results in the following CO limits, including malfunctions, for the following averaging times:

30-day rolling average: 559 ppmvd @ 3% O₂

60-day rolling average: 518 ppmvd @ 3% O₂

90-day rolling average: 501 ppmvd @ 3% O₂

182-day rolling average: 480 ppmvd @ 3% O₂

365-day rolling average: 467 ppmvd @ 3% O₂

As indicated, these values are only slightly higher than those presented above, which exclude malfunction events.

Attached is a graph of the rolling average CO concentration for Boiler No. 8 versus time for the 10-day, 30-day and 365-day rolling averages, including malfunctions [See submittal for Figure

C-2]. This plot is similar to the preceding data/plot, except that the emissions are somewhat higher due to the malfunctions. The CO data based on a 365-day rolling average is much less variable than a 10-day or 30-day rolling average. The data for Boiler No. 8 demonstrate that the EPA's proposed 10-day rolling average limit would have been exceeded on 117 days over this approximate 4-year period, and if the limit were based on a 30-day rolling average, 82 exceedances of the limit would have occurred. However, no exceedances of the proposed limit would have occurred based on a 365-day rolling average, and the inclusion of malfunctions has very little effect on the 365-day rolling average. Review of the graphs show that malfunctions add about 50 ppmvd @ 3% O₂ to the 365-day rolling average.

To determine an appropriate CO CEMS-based limit for existing sources, some allowance must be made to account for the fact that data is available from only one source- U.S. Sugar Boiler No. 8. EPA's MACT Floor analysis showed that Boiler No. 8 was ranked second within the top 5 sources. Using the test averages from EPA's analysis, Boiler No. 8 averaged 567 ppmvd @ 3% O₂ over all tests, while the average of all boilers in the top 5 was 1,089 ppmvd @ 3% O₂. The ratio of these two results is 1.9. It therefore seems appropriate to adjust the new source MACT floor limit by this ratio, to account for the variability in CO data for all sources ranked in the top 5.

If EPA retains its proposed new source limit of 730 ppmvd, then the existing source CO CEMS limit would be 1,390 ppmvd @ 3% O₂. If some lower new source limit is determined based on the above data, the existing source limit should be derived accordingly.

Response: The corresponding CO CEMS data in the EPA ICR Databases have been given appropriate flags for periods of startup, shutdown, and malfunction (SSM) as denoted by the commenter. The commenter also provided additional CO CEMS data, which have been incorporated into the EPA ICR Databases and factored into the calculation of the alternative CO CEMS-based limit for the Hybrid Suspension Grate subcategory. EPA acknowledges the data analysis submitted by the commenter. For a discussion on the results of this data analysis, please see the response to comment EPA-HQ-OAR-2002-0058-3504-A1, excerpt 31.

For a response to the request for a 365-day rolling average to account for high variability in bagasse-fired boilers, see response to comment EPA-HQ-OAR-2002-0058-3504-A1, excerpt 31.

The CO CEMS variability was calculated using a 99 percent UPL and not a 99.9 percent UPL. The resultant emission limit alternative was based on either the 99 percent UPL or the maximum average of the top 6%, whichever was higher. Specifically for Hybrid Suspension Grate units, the CO CEMS-based alternative emission limit is less stringent for both existing and new sources than in the December, 2011 proposed reconsideration of the rule. We have also changed to a 30-day rolling average in lieu of a 10-day rolling average. EPA believes these changes provide enough flexibility to sources to account for the inherent variability of CO emissions without minimizing the environmental impact of the rule.

For the reasons specified in the preamble to the December 23, 2011 rule notice (76 FR 80598), EPA has retained a 99% UPL in its calculation of both the stack test-based and CEMS-based CO MACT floors. Where justified by available data, EPA elected to lengthen the averaging period to a 30-day rolling average in lieu of a 10-day rolling average. The Hybrid Suspension Grate subcategory was one such subcategory which has been switched to a 30-day rolling average.

EPA agrees with the commenter that the malfunction periods do not qualify for affirmative defense and should be factored into the MACT floor calculation since these flagged 'malfunctions' occur too often. We revised the analysis of the CO CEMS data to include the flagged malfunction periods. The final rule contains the revised emission limits. See also the response to comment EPA-HQ-OAR-2002-0058-3451-A1, excerpt 9. This excerpt may be found in the CO CEMS "Statistical Analysis" section of this comment response document.

The EPA disagrees with the commenter's suggestion to apply a ratio of average stack test data from best performers to the results of a CO CEMS analysis. The datasets for stack test data and CO CEMS data are separate and the EPA does not agree that a ratio of stack test data would be applicable to longer term CO CEMS data in this rulemaking since the stack tests are conducted at consistent loads, whereas the CO CEMS represents emissions over a wide variety of loads and fuel conditions. Further, the EPA has finalized an approach that analyzes the data from the top 12 percent of units that has been made available to the EPA at the time of this rulemaking. Several other units in other subcategories conducted voluntary CO CEMS testing to obtain additional CO CEMS data and the EPA has considered these other data in its analysis. The other units in the hybrid suspension grate subcategory had ample opportunities to submit additional data for the CO CEMS analysis, but no other data was received by the August 8, 2012 cutoff for consideration of additional data for this rulemaking. For more information on the August 8, 2012 deadline, please see the memo titled "Handling and Processing of Corrections and New Data in the EPA ICR Databases – Revised August 2012" in the docket.

Commenter Name: Kevin G. Desharnais, Attorney, Mayer Brown LLP

Commenter Affiliation: United States Sugar Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3496-A1

Comment Excerpt Number: 9, 10

Comment: A review of the CEMS data submitted by U.S. Sugar for its Boiler Number 8 clearly shows the need for a longer averaging period for demonstrating compliance with the CO CEMS-based limit for bagasse boilers. The monitoring data shows wide swings in 10-day and 30-day rolling averages for both CO and O₂ as a result of changes in operating conditions over time. In contrast, the 12-month rolling average data shows remarkable consistency within a reasonable range of values for both CO and O₂ and presents a more appropriate measure of compliance over time.

In order for the CO CEMS standard to be a viable compliance alternative, a longer averaging time must be allowed. In order to account for the natural variability in emissions over time, we believe that a 12-month rolling average would be more appropriate for bagasse boilers. In the Reconsideration Proposal, EPA notes that it expects to receive additional CEMS data, which "will likely change the CO CEMS floors, and may also result in different averaging times." 76 Fed. Reg. at 80611. U.S. Sugar requests that EPA reconsider the CO CEMS standard and establish a 12-month rolling averaging time applicable to bagasse boilers.

Response: We agree that a longer averaging time is warranted for Hybrid Suspension Grate units combusting biomass or bio-based solid fuels. However, we do not agree that a 12-month rolling average is appropriate. For additional information on the suggested 12-month rolling

average for this subcategory, please see the response to comment EPA-HQ-OAR-2002-0058-3504-A1, excerpt 31.

4H08. Existing Results: Wet Biomass Stoker/Sloped Grate/Other

Commenter Name: Stephen E. Woock

Commenter Affiliation: Weyerhaeuser Company

Document Control Number: EPA-HQ-OAR-2002-0058-3523-A1

Comment Excerpt Number: 5

Comment: We support EPA's decision to propose additional subcategories for CO for biomass units and to provide a longer averaging period limit as an alternative compliance option. The resulting proposed limits are more feasible for specific combustion unit designs by recognizing differences in the biomass fuel moisture characteristics.

However, for our boilers with existing CO CEMS that burn green biomass fuels and would be defined as "wet" biomass stoker units we are concerned with feasibility to demonstrate compliance with the proposed alternative 10-day limit.

Response: The EPA thanks the commenter for their support of additional subcategories for biomass units and a longer averaging period as an alternative compliance option. The CO CEMS-based limits have been revised in the final rule. Based on additional CO CEMS data submitted during the public comment, the CO CEMS-based limit for Stokers/Sloped Grate/Other units designed to combust wet biomass or bio-based solid fuels in the final rule has been revised and the averaging time for this subcategory was also revised to a 30-day (i.e., 720-operating hour) rolling average. The EPA believes the less stringent limit based on a longer averaging period mitigates any concerns on achievability.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 48

Comment: Many biomass boiler operators will be able to utilize the stack test-based CO limits and associated 30-day average oxygen monitoring to comply. However, some of our members with top performing biomass fluidized bed boilers and biomass stoker units equipped with sophisticated combustion controls like over-fired air, cannot say with certainty that they will meet the proposed CO CEMS-based limits 100% of the time. CO emissions vary significantly with changes in load and fuel quality to the point that some of the units on which EPA is relying to set the MACT floors cannot comply all year round.

The burning of wood or wood-derived fuels, by themselves or in combination with other fossil fuels, involves very different combustion conditions than fossil fuel. The same stringent limitations on CO emissions that apply to fossil fuel-fired boilers with good combustion practices are not relevant. The high moisture content typical of most wood-derived fuels necessitates a larger than usual area of refractory surface to dry the fuel before combustion. Sufficient secondary air must be supplied over the fuel bed to burn the volatiles that account for

most of the combustible material in the fuel. However, the air should not be so excessive as to cool the combustion flame.

Wood residue is typically comprised of about 50% moisture and has a heat value of about 4500 Btu/lb (as fired), compared with typical heat values of about 12,000 Btu/lb for coal, 18,750 Btu/lb for oil and 24,000 Btu/lb for gas (as methane). Thus, wood residue has significantly lower heat value on a per pound basis than most fossil fuels. The lower heat value generally translates to lower adiabatic flame temperatures, which leads to lower efficiencies of combustion of the carbon content of wood. EPA's AP-42 emission factor document gives, for example, a range of 0.7 to 21 lb CO/ton wood residue, with an average of 6.6 lb/ton (or about 100 to 2900 ppm CO, average 900 ppm CO @3% O₂).

In an NCASI study,³⁴ detailed analysis of CO monitoring data corresponding to three wood-fired boilers representative of recent design and operated in a "normal" manner showed that average CO emissions ranged between 0.18 and 0.50 lb/106 Btu for a 150 hour monitoring period (about 225 to 625 ppm CO at 3% O₂). While a correlation between CO emissions and flue gas oxygen content was observed, high CO emissions resulted when either too little or too much excess air was used. A well-operated biomass boiler will have much higher CO emissions than most fossil fuel-fired boilers, even when optimally operated using good combustion practices.

[Footnote: "Carbon Monoxide Emissions from Selected Combustion Sources Based on Short-Term Monitoring Records," NCASI Technical Bulletin No. 416, January 1984.]

Response: See the response to comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 47. This excerpt may be found in the CO CEMS "Existing Results: Biomass FB" section of this comment response document.

Commenter Name: Rick Rosvold

Commenter Affiliation: Xcel Energy Services, Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3682-A2

Comment Excerpt Number: 1

Comment: Bay Front boilers #1 and #2 were originally designed to burn 100% coal. In the mid-1970s provisions were added to the boilers to allow waste wood to be blended with the coal. By 1979 either boiler was able to be fired entirely on wood, coal or blends of wood and coal. Shredded tires (tire derived fuel or "TDF") were added to the wood fuel mix in the mid-1980s to enhance combustion. Co-firing wood and coal ceased in the late 1990s due to ash fouling and slagging problems caused by file interactions of the fuels and the ash properties of the two fuels. The plant now operates primarily on woody biomass with less than a 2% TDF mixture by volume.

When wood waste was first introduced at the plant, there were no regulations in place requiring the plant to comply with a certain carbon monoxide ("CO") limit. With the passage of Wisconsin's air toxics rule in 1988, the plant was required to demonstrate "good combustion" technology when burning waste wood in order to comply with tile rule. The good combustion technology was determined to be the ability to meet a carbon monoxide limit of 500 parts per million ("ppm") corrected to 7% oxygen ("O₂").

Stack tests of these boilers conducted in May 1991 showed the CO emission level corrected to a dtT basis of 7% O₂ while burning 100% wood waste ranged from 1,533 ppm to 2,869 ppm. The company hired an engineering firm to perform a study to determine how the CO emissions could be reduced while burning 100% wood waste in these boilers. As a result of this study, in the years 1992 through 1994 the company installed side wall overfire air nozzles and modified the front and rear wall overfire air nozzles to improve combustion efficiency. The engineering firm believed a properly designed overfire air system would greatly improve wood combustion and result in CO levels below 500 ppm corrected to 7% O₂.

Stack tests conducted after the overfire air changes in 1994 showed CO emissions averaged 345 ppm @ 7% O₂. In 1995, CO continuous emissions monitors ("*CF~Ms*") were installed on both boilers, so the plant has been continuously monitoring its CO emissions for 17 years and has taken steps over those years to continue to optimize combustion and lower emissions. Today, excluding startup and shutdown, the plant may experience less than 5 hours per year when emissions from the boilers exceed 600 ppm CO @ 7% O₂. These higher levels are primarily due to poor fuel quality and/or switching from wood to coal or coal to wood. Over the past three years (2009 - 2011), CO emissions from these boilers have averaged less than 300 ppm @ 7% O₂.

Response: For a response to the differences between CO emissions from biomass and coal combustion, please see response to EPA-HQ-OAR-2002-0058-3521-A1, Excerpt No. 47. This excerpt may be found in the CO CEMS "Existing Results: Biomass FB" section of this comment response document.

EPA has revised the alternative CO CEMS-based emission limits for all subcategories in the final rule. The resultant limit for Stokers burning wet biomass is less stringent than the alternative CO CEMS-based limit in the December 23, 2011 proposed reconsideration of the rule.

Commenter Name: Richard D. Garber

Commenter Affiliation: Boise Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3686-A2

Comment Excerpt Number: 14

Comment: EPA should address CO emission limit achievability for wet biomass stoker boilers and the compliance averaging time for those units equipped with CO CEMS for compliance demonstration.

Some biomass boiler operators will be able to utilize the stack test-based CO limits and associated 30-day average oxygen monitoring to comply. However, several of Boise's boilers are in the wet biomass stoker design subcategory and are required to monitor compliance with existing Title V air permit limits using CO GEMS due to prior permit actions. These units will be required to *continuously* meet the 10-day average 410 ppm CO limit at 3% O₂. We have two concerns with the standard: 1) the averaging period is likely too short to fully capture seasonal fuel variability and the variability in steam demand that are experienced by load-following boilers typically operated at paper mills; and 2) the 410 ppm limit is too low to be met continuously by all of the units in the MACT floor. Rapid changes in fuel feed rate necessary to

meet changing steam demands, especially during seasonal periods of wet fuel, can cause short-term spiking of CO emissions and generally higher averages than during periods of dry fuel availability. Boise is concerned of reports from several companies that have installed sophisticated combustion controls like over-fired air, but yet still cannot say with certainty that they will meet the proposed 410 ppm CO GEMS-based limits 100% of the time. CO emissions vary significantly with changes in load and fuel quality and seasonal moisture content to the point that some of the units on which EPA is relying to set the MACT floors cannot comply all year round.

Response: For a response to how CO emissions vary with changes in load and fuel quality and seasonal moisture content, as well as concerns over the achievability of the limit, please see response to EPA-HQ-OAR-2002-0058-3521-A1, Excerpt No. 47. This excerpt may be found in the CO CEMS "Existing Results: Biomass FB" section of this comment response document. For a response to overfire air and its benefit as a control for CO emissions, please see response to EPA-HQ-OAR-2002-0058-3682-A2, Excerpt No. 1.

Commenter Name: Richard D. Garber

Commenter Affiliation: Boise Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3686-A2

Comment Excerpt Number: 15

Comment: The burning of wood or wood-derived fuels, by themselves or in combination with other fossil fuels, involves very different combustion conditions than fossil fuel. The same stringent limitations on CO emissions that apply to fossil fuel-fired boilers with good combustion practices are not relevant. The high moisture content typical of most wood-derived fuels necessitates a larger than usual area of refractory surface to dry the fuel before combustion. Sufficient secondary air must be supplied over the fuel bed to burn the volatiles that account for most of the combustible material in the fuel. However, the air should not be so excessive as to cool the combustion flame. Wood residue is typically comprised of about 50% moisture and has a heat value of about 4500 Btu/lb (as fired), compared with typical heat values of 12,000 Btu/lb for coal, 18,750 Btu/lb for oil, and about 24,000 Btu/lb for gas (as methane). Thus, wood residue has significantly lower heat value on a per pound basis than most fossil fuels. The lower heat value generally translates to lower adiabatic flame temperatures, which leads to lower efficiencies of combustion of the carbon content of wood. EPA's AP-42 emission factor document gives, for example, a range of 0.7 to 21 lb CO/ton wood residue, with an average of 6.61lb/ton (or about 100 to 2900 ppm CO, average 900 ppm co @3% O₂).

In an NCASI study,⁴ detailed analysis of CO monitoring data corresponding to three wood-fired boilers representative of recent design and operated in a "normal" manner showed that average CO emissions ranged between 0.18 and 0.50 lb/106 Btu for a 150 hour monitoring period (about 225 to 625 ppm CO at 3% O₂). While a correlation between CO emissions and flue gas oxygen content was observed, high CO emissions resulted when either too little or too much excess air was used. A well-operated biomass boiler will have much higher CO emissions than most fossil fuel-fired boilers, even when optimally operated using good combustion practices.

[Footnote]

(4) "Carbon Monoxide Emissions from Selected Combustion Sources Based on Short-Term Monitoring Records," NCASI Technical Bulletin No. 416, January 1984.

Response: For response, see response to EPA-HQ-OAR-2002-0058-3521-A1, Excerpt No. 47. This excerpt may be found in the CO CEMS "Existing Results: Biomass FB" section of this comment response document.

Commenter Name: Rick Rosvold

Commenter Affiliation: Xcel Energy Services, Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3682-A2

Comment Excerpt Number: 4

Comment: Xcel Energy has reviewed the spread sheet supplied by the United States Environmental Protection Agency ("USEPA") with the data used to calculate the 99% Upper Prediction Limit ("UPL") for CO from Wet Stoker Biomass Boilers and the subsequent limit for CO (Appendix B-8 to CO CEMS MACT Floor Analysis Memorandum)¹. The spread sheet shows approximately 30% of the data coming from the Boise Cascade Wallula plant, which is described in the spread sheet as a co-fired hogged fuel and natural gas boiler

Xcel Energy believes it is inappropriate to include CO data from a wet biomass stoker boiler co-firing natural gas when calculating the 99% UPL and subsequent CO limit for wet biomass stoker boilers not co-firing natural gas or perhaps only topping with natural gas. Controlling combustion air demands in a wet biomass boiler is the greatest challenge to minimizing CO emissions. Wood fuel quality varies more than coal quality. Proper tuning of the automatic combustion controls is more important when firing wood. Operators must pay close attention, and periodically adjust feeders to maintain even fuel distribution and adjust the ratio of overfire to underfire air. Wood combustion requires more excess air and more overfire air than coal combustion. Combustion in a wood fired boiler is not instantaneous. The combustion air cannot be distributed evenly to a solid fuel in the combustion zone. The moisture and heat (BTU) content of the biomass are variables that affect oxygen demand greatly as the fuel is metered into the boiler. This fuel variability causes savings in the combustion air input as boiler control chases the oxygen demand of the fuel. CO formation occurs as oxygen is consumed unevenly and incompletely in the combustion zone. Natural gas co-combustion allows for reducing the variability of the air demand and better distribution of heat in wet biomass combustion, and will reduce the CO formation. Xcel Energy believes that including Boise Cascade Wallula data is perhaps an oversight by the USEPA and requests that the data be removed from this data set.

[Footnote]

(1) ERG Memorandum dated November 2011 to Brian Schrage USEPA, Subject: CO CEMS MACT Floor Analysis for the Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants - Major Source.

Response: For a response to comments regarding the variability of wet biomass fuel and the corresponding effects on excess air, overfire air, and CO formation, please see response to EPA-HQ-OAR-2002-0058-3521-A1, Excerpt No. 47. This excerpt may be found in the CO CEMS "Existing Results: Biomass FB" section of this comment response document.

EPA acknowledges that CO emissions may be reduced by co-firing natural gas, but disagrees that these data should be removed from consideration in the CO CEMS-based 99% UPL calculation. CEMS data are available for multiple Stokers burning wet biomass, some co-firing natural gas and some combusting 100% biomass fuel. EPA believes that the large amount of data for the subcategory minimizes any effect the lower emissions from co-firing natural gas could potentially have on the 99% UPL.

Commenter Name: Rick Rosvold

Commenter Affiliation: Xcel Energy Services, Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3682-A2

Comment Excerpt Number: 5

Comment: The Company also looked at individual data points used to establish the limit for this sub-category, and it appears that several were incorrectly included. It appears certain data points were collected when the unit was either offline or burning alternative fuels. CO concentrations below 50 ppm are probably not representative of operations on strictly biomass, but without having more background information on the Sierra Pacific Lincoln facility's operations, we have conservatively excluded only those data points below 10 ppm in the numbers presented below.

Response: EPA disagrees with assuming certain data points represent periods of startup, shutdown, malfunction, or minimal biomass combustion. The data in the EPA ICR Databases reflects the CO CEMS data as reported to EPA. Without actual documentation showing that these low CO emissions correlate to periods of startup, shutdown, malfunction, or minimal biomass combustion, EPA cannot reasonably disregard those data.

Commenter Name: Rick Rosvold

Commenter Affiliation: Xcel Energy Services, Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3682-A2

Comment Excerpt Number: 6

Comment: Xcel Energy has recalculated the 99% UPL after removing the inappropriate data included from the Wallula facility and 3 data points where the CO concentration was below 10 ppm from the Sierra Pacific Lincoln facility. (EPA used this data to determine the CO concentration limit from CEMS data as 410 ppm CO at 3% O₂). The recalculated 'normal' data calculations deliver a value of 468 ppm CO at 3% O₂ and the 'log normal' calculations present a value of 441 ppm CO at 3% O₂. Xcel Energy believes these are the appropriate values to calculate a CO limit for wet stoker biomass boilers based on the data available. Xcel Energy also suggests that the USEPA consider removing all data below 50 ppm or investigate more thoroughly the operations at the Sierra Pacific Lincoln facility to insure those data below 50 ppm are appropriately included. Xcel Energy encourages the USEPA to use these assumptions when setting the final limit.

Response: For a response to the request to remove all data below 50 ppm, please see response to EPA-HQ-OAR-2002-0058-3682-A2, Excerpt No. 5.

Energy Assessment

5A. Scope of Assessment

Commenter Name: Jessica Bridges

Commenter Affiliation: United States Clean Heat & Power Association (USCHPA)

Document Control Number: EPA-HQ-OAR-2002-0058-3501-A1

Comment Excerpt Number: 12

Comment: EPA proposes to restrict the energy assessment to sources and uses (our terms) on-site. USCHPA questions this. Removing the benefit obtained by reducing electricity purchases can undermine unnecessarily the benefits of CHP installations, especially one-off installations. Unfortunately when CHP is involved, this approach will undervalue the benefit of the CHP system, both in energy savings and in emissions reductions.

As indicated earlier, CHP has off-site benefits because the site doesn't have to buy so much electricity from "away." The energy savings and the CO₂ avoidance in the quotation from Oak Ridge National Laboratory⁵ cited above and referenced in 76 FR, 80606-80620 is based upon avoidance of energy consumption both at the site and away.

[Footnote]

(5) Oak Ridge National Laboratory, Combined Heat And Power, Effective Energy Solutions for a Sustainable Future, December 1, 2008, ORNL/TM-2008/224. P3. ORNL's data cites 1.9 quads of fuel savings and 248 MMTs of CO₂ savings based upon 85GW deployed. The lower numbers represent current estimates based upon 82GW deployed.

Response: We agree that there is a benefit in reducing electricity purchases but the applicability of the rule is limited to boilers and process heaters located at a major source facility.

Commenter Name: Robin Mills Ridgway

Commenter Affiliation: Purdue University

Document Control Number: EPA-HQ-OAR-2002-0058-3668-A2

Comment Excerpt Number: 20

Comment: Further clarification is required to limit the scope of effort relative to the percent of affected boiler(s) and process heater(s) energy output for different size facilities. Specifically, it is unclear how the percentages in the Energy assessment definition are to be applied. Purdue believes that EPA's intentions are to limit the scope of assessment based on energy use by discrete segments of a facility, and not by a total aggregation of all individual energy using elements of a facility, because the latter would be disjointed and unwieldy at best. The applicable discrete segments of a facility could vary significantly depending on the site and its complexity. However, Purdue believes the following addition to the Energy assessment definition in §63.7575 would help resolve current problems and allow for more streamlined assessments:

"...(4) The on-site energy use systems serving as the basis for the percent of affected boiler(s) and process heater(s) energy output in (1), (2), and (3) above may be segmented by production area or energy use area as most logical and applicable to the specific facility being assessed (e.g., product X manufacturing area; product Y drying area; Building Z)."

Response: We agree that the scope of the energy assessment and the on-site energy use system needs clarification. Our intent was to cover within the energy assessment the boiler system and discrete energy use systems. That is, if a boiler is supplying steam heat to several buildings, each building would be considered a discrete and separate energy use system. The definition of "Energy assessment" has been revised as suggested by the commenter to better clarify the meaning of or the extent of an on-site energy use system.

Commenter Name: Russell A. Wozniak

Commenter Affiliation: The Dow Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3449-A1

Comment Excerpt Number: 32

Comment: The definition of Energy Use System should be clarified.

In the preamble, V.H.1, Energy Assessment Scope (p. 80614 of FR), the EPA said the final definition for "Energy Use System" was intended only to list examples of potential systems that may use the energy generated by affected boilers and process heaters. Table 3, item 4(c) was changed to reflect the *inventory* of major energy consuming systems are those from affected boilers and process heaters; but the definition of "**Energy use systems**" does not clearly state the intended scope are only those systems using energy from the affected boilers and process heaters.

A large integrated site can contain many boilers and process heaters serving many energy users. Some of those boilers and process heaters could be excluded per 63.7491, excluded in definition of Boilers (such as Waste Heat Boiler burning natural gas, refinery gas, or other Gas 1), or excluded for some other reason. To clarify that the scope of the Energy Assessment is only limited to energy users associated with affected boilers and process heater, the definition of "Energy Use System" should be modified as recommended below.

Energy use system includes, but is not limited to, process heating; compressed air systems; machine drive (motors, pumps, fans); process cooling; facility heating, ventilation, and air conditioning systems; hot water systems; building envelop; and lighting. Energy use systems are only those systems using energy clearly produced by affected boilers and process heaters.

Response: We agree and the definition of "Energy use systems" is revised as suggested by the commenter.

Commenter Name: Russell A. Wozniak

Commenter Affiliation: The Dow Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3449-A1

Comment Excerpt Number: 33

Comment: EPA's proposal requires that the boiler system and energy use system that accounts for at least 20 percent of the energy output will be evaluated to identify energy savings opportunities if the heat input is greater than 1.0 trillion Btu per year. At larger petrochemical complexes, the energy output from a regulated boiler could be transferred to perhaps a number of individual operating plants that use the energy in the form of steam for distillation columns, reactors, etc. EPA should clarify how to define an Energy Use System for cases where there are multiple users of the utilities. For example, should the owner/operator apply the term Energy use System across a single chemical manufacturing process unit or apply it across a set of process units even if the processes are different? We suggest that the term process unit be considered analogous to the term Energy Use System for this regulation and that industry follow the regulations in individual 40 CFR 63 subparts in order to determine the boundaries of a process unit.

Response: We agree that the term "energy use system" needs clarification. See the response to comment EPA-HQ-OAR-2002-0058-3668-A2, excerpt 20 which indicates how the definition of "Energy assessment" is revised to clarify this issue.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 120

Comment: EPA comment responses indicate that it was EPA's intention to only include within the scope of the energy assessment the equipment and facilities that are associated with energy output from the regulated combustion units. However, the energy use system definition included at 63.7575 still extends beyond that intended scope for facilities which purchase electricity for operation of compressed air systems, machine drive (motors, pumps, fans), process cooling, facility HVAC, building envelop(e), and lighting.

Although we continue to believe that EPA is not justified in its inclusion of this requirement in the Boiler MACT, if the energy assessment is retained as a beyond the floor requirement, the scope should be reduced to the boiler and its auxiliaries.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3449-A1, excerpt 32.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 113

Comment: The Reconsidered Rule amendment to the scope of the assessment does not cure its illegality, and is arbitrary. In the Preamble, EPA asserts that it revised the requirement to address comments that the scope of the assessment was too broad. However, EPA pared back the scope of the assessment in one minor respect, which does not cure the problem. The assessment as re-proposed in the Reconsideration Rule remains illegally broad. The rule still defines "energy use system(s)" to include without limitation, process heating & cooling, in addition to boiler systems, machine drives, HVAC, and lighting. Further, the proposed amendment creates a division among

affected sources that arbitrarily imposes a greater burden on facilities with peripheral power demand supplied by energy made onsite than on facilities that rely more heavily on purchased power.

The rule continues to define energy assessment to include "energy use system(s)." 76 FR 80651. EPA now proposes to cover only "energy use systems that are under the control of the owner/operator." 76 Fed. Reg. 80664.

EPA proposes to amend this definition because, as EPA explains, it did not intend the scope of energy assessments to include "energy use systems using electricity purchased from an off-site source" nor "energy use systems located off-site." 76 Fed. Reg. 80664. EPA excludes them because EPA concludes they are inconsistent with its intent to cover systems that are directly related to the emissions of the regulated boiler. CIBO agrees they should not be covered by this rule, nor should any of the other energy using systems that continue to be covered by the rule.

Energy use systems located off-site and systems that run on purchased power should never have been covered by the rule, because the source category and emission source is the boiler. Although EPA appears to concur that scope is a concern, in fact EPA selectively addresses the comments, focusing only on the systems off-site and running on purchased power. EPA does not address the other more fundamental concern, relating to all other systems still covered by the rule.

While the scope of the covered energy use systems should certainly be narrowed, EPA's proposed exclusion of systems that run on purchased power creates an arbitrary distinction among efficiency measures at a facility based on the source of power. There is no logic to requiring a more reaching assessment of energy systems by sources that depend more heavily power produced onsite than by sources that purchase power. EPA's logic – the sole basis of this regulatory requirement – is that reduced energy demand = less fuel used = lower emissions from the combustion source. It matters little whether the power is produced by a utility or by an industrial boiler, if EPA rationally applies its reasoning to regulatory requirements. In addition, it is not always apparent what the source of the power is for any individual energy-consuming system at a facility. As EPA has made clear, the goal is "to reduce the facility energy demand which would result in reduced fuel use." 76 Fed. Reg. 15,573. While CIBO supports EPA's narrowing the scope of the energy assessment, the current definition remains over-broad and lacking in record support and legal authority.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3449-A1, excerpt 32 for a response on definition and clarification of "energy use system(s).

See the response to comment EPA-HQ-OAR-2002-0058-3501-A1, excerpt 12 for a response on clarification of energy use systems located off-site.

Commenter Name: Barry Christensen

Commenter Affiliation: Occidental Chemical Corporation (OCC)

Document Control Number: EPA-HQ-OAR-2002-0058-3477-A1

Comment Excerpt Number: 10

Comment: OCC fully supports the clarification of the scope of the required energy assessments. This includes the final definition for “Energy use system,” which is intended to clearly limit the scope of the energy assessment to equipment that is located on-site and associated with the affected boilers and process heaters.

Response: The EPA thanks the commenter for their support.

Commenter Name: David A. Buff, Golder Associates Inc.

Commenter Affiliation: Florida Sugar Industry (FSI)

Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1

Comment Excerpt Number: 45

Comment: EPA’s definition of an "energy use system" in Section 63.7575 is very broad and includes "machine drive (motors, pumps, fans), process cooling, facility heating, ventilation, and air-conditioning systems; hot water systems; building envelope; and lighting." 76 F.R. 80651. It is not appropriate to include energy assessment requirements in the Proposed Boiler MACT, but if the energy assessment is retained by EPA as a beyond-the-floor requirement, the scope of the energy assessment should be reduced to only include the boiler and its auxiliary components. Facilities and systems such as heating, ventilation, and air conditioning systems, hot water systems, the building envelope, and lighting, should be removed from the scope of any energy assessment.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3449-A1, excerpt 32.

Commenter Name: Felix Mestey, on behalf of Donald R. Schregardus

Commenter Affiliation: Clean Air Act Services Steering Committee, Department of Defense (DoD)

Document Control Number: EPA-HQ-OAR-2002-0058-3427

Comment Excerpt Number: 6

Comment: EPA should further clarify the equipment that must be included in the energy assessment. In some places, the rule refers to conducting the assessment on the boiler system (§63.7575), and in other places there are references to conducting the assessment on the entire facility (Table 3 to Subpart DDDDD), which implies that the assessment needs to include all energy consuming activities. EPA should clarify the parts of the boiler and energy use systems and facilities that are to be included in the energy assessment. This uncertainty could result in affected facilities expending unnecessary technical hours and incurring unnecessary costs due to ambiguity in the scope of the energy assessments. DoD believes that the scope should be limited to the boiler and process heater systems and only those energy use systems that are directly connected and served by the boiler and process heater systems.

Recommendation:

Revise §63.7500(c) and the "*if your unit is...*" column for requirement 4 in Table 3 to Subpart DDDDD to clarify that the energy assessment is not applicable to limited-use units or small units as follows:

§63.7500 (c) Limited-use boilers and process heaters must complete a biennial tune-up as specified in § 63.7540. They are not subject to the emission limits in Tables 1 and 2 to this subpart, the annual tune-up or the energy assessment requirements in Table 3 to this subpart, or the operating limits in Table 4 to this subpart. ~~Major sources that have limited-use boilers and process heaters must complete an energy assessment as specified in Table 3 to this subpart if the source has other existing boilers subject to this subpart that are not limited-use boilers.~~

(d) Boiler and process heaters systems with a rated capacity of less than 5 MMBtu/hr are not subject to the energy assessment requirement in Table 3 to this subpart.

Table 3 to Subpart DDDDD, "if your unit is..." column, requirement 4 as proposed: An existing boiler or process heater located at a major source facility, except for limited-use units and units with a rated capacity of less than 5 MMBtu/hr.

Revise the definition of "boiler system" in §63.7575 so that it only includes the boilers and those components directly connected and serving "energy use systems."

Boiler system means the boiler and associated components, such as, the feed water system, the combustion air system, the fuel system (including burners), blowdown system, and combustion control systems directly connected and serving the~~and~~-energy ~~consuming~~ use systems.

Revise the energy assessment requirement in the "You must meet the following..." column of Table 3 to Subpart DDDDD as follows. Most of the changes shown in ~~strikeout~~ are to make the requirements more consistent with the area source rule. The changes shown in ~~bold strikeout~~ will further clarify the intended scope of the energy assessments since the term "facility" could be interpreted much broader than the affected units.

Must have a one-time energy assessment performed ~~on the major source facility~~ by a qualified energy assessor. An energy assessment completed on or after January 1, 2008, that meets or is amended to meet the energy assessment requirements in this table, satisfies the energy assessment requirement. The energy assessment must include:

- a. A visual inspection of the boiler or process heater system.,
- b. An evaluation of operating characteristics of the ~~facility boiler or process heater systems~~, specifications of energy using systems, operating and maintenance procedures, and unusual operating constraints,
- c. An inventory of major energy ~~consuming~~ use systems consuming energy from affected boilers and process heaters and which are under the control of the boiler/process heater owner/operator.,
- d. A review of available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage,
- e. A review of the facility's energy management practices and ~~provide~~ recommendations for improvements consistent with the definition of energy management practice, if identified,
- f. A list of major energy conservation measures that are within the facility's control,

g. A list of the energy savings potential of the energy conservation measures identified, and h. A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments.

Response: Our intent was to limit the scope of the energy assessment to boilers and process heaters affected by the rule and only those energy use systems that are directly connected on-site and served by the affected boiler and process heater. We did not intend to include limited-use units within this scope. We have revised §63.7500(c) as suggested by the commenter. We disagree with the comments that units less than 5 MMBtu/hr should not be included in the energy assessment. The commenter provides no explanation for its recommendation that such units be excluded. We have revised Table 3 and the definition of "Boiler system" to better clarify the scope of the energy assessment.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 110

Comment: EPA makes clear in the proposed Reconsidered Rule that the definition of "energy use system" is a non-exclusive list of examples of systems that a source may be required to include in its energy assessment. 76 Fed. Reg. 80,651. EPA emphasizes the open-endedness of this requirement in response to a comment, stating that the definition of "energy use system" is "intended only to list examples of potential systems that may use the energy generated by affected boilers and process heaters." 76 Fed. Reg. 80,615. Therefore, as broadly as "energy use system" is already defined, as applied to specific sites, the assessment requirement could be even broader.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3449-A1, excerpt 32.

Commenter Name: Randal G. Oswald

Commenter Affiliation: Integrys Energy Group

Document Control Number: EPA-HQ-OAR-2002-0058-3659-A2

Comment Excerpt Number: 11

Comment: Under the final rule, the affected sources are "all existing industrial, commercial, and institutional boilers and process heaters" and "each new or reconstructed industrial, commercial, or institutional boiler or process heater."¹⁵ A process heater is defined as "an enclosed device using controlled flame, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material for use in a process unit, instead of generating steam."¹⁶ A boiler is defined as "an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water."¹⁷

The affected source (*i.e.*, the process heater or boiler) clearly does not encompass the "boiler system" or "energy use systems" located at the major source. The fact that "including all of the energy using systems in the energy assessment can result in decreased fuel use"¹⁸ does not remedy this defect. For example, EPA's definition of "boiler system" includes "the boiler *and*

associated components, such as, the feedwater system, the combustion air system, the fuel system (including burners), blowdown system, combustion control system, and energy consuming systems."¹⁹ Similarly, the "energy use system" includes "process heating; compressed air systems; machine drive (motors, pumps, fans); process cooling; facility heating, ventilation, and air conditioning systems; hot heater systems; building envelop; and lighting."²⁰ Both the "boiler system" and "energy use system" by definition include components outside the boiler and process heater.

Accordingly, § 112 does not provide EPA with the authority to promulgate a requirement to conduct an energy assessment on energy use systems or parts of the "boiler system" that do not consist of the boiler or process heater, because such systems are not sources in the listed source category.

[Footnotes]

(15) 40 C.F.R. § 63.7490(a)(1)-(2).

(16) 40 C.F.R. § 63.7575. (17) 40 C.F.R. § 63.7575.

(18) 76 Fed. Reg. at 15632.

(19) 40 C.F.R. § 63.7575.

(20) 40 C.F.R. § 63.7575.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3449-A1, excerpt 32 and the response to comment EPA-HQ-OAR-2002-0058-3427, excerpt 6. **Commenter Name:** Pat Dennis

Commenter Affiliation: Archer Daniels Midland Company

Document Control Number: EPA-HQ-OAR-2002-0058-3670-A2

Comment Excerpt Number: 11

Comment: EPA has authority to regulate HAP emissions from major sources under section 112(d) of the Clean Air Act. This attempt to further regulate the way major sources consume energy under this rule is beyond EPA's authority. EPA should eliminate its definitions of "boiler system" and "energy use system". EPA should further limit the scope of energy assessments to "boiler(s)" and "process heater(s)" as currently defined.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3449-A1, excerpt 32.

Commenter Name: Allison Watkins, Baker Botts

Commenter Affiliation: Class of '85 Regulatory Response Group

Document Control Number: EPA-HQ-OAR-2002-0058-3608-A1

Comment Excerpt Number: 12

Comment: The Class of '85 requests that EPA eliminate the requirement that facilities complete a one-time energy assessment to identify cost-effective energy conservation measures for the boiler system and its energy use systems located at the source. EPA does not have the authority

under § 112 to go beyond the sources listed in a source category and impose requirements on other aspects of a facility.

EPA is a federal agency; it has no constitutional or common law existence or authority, but only the authority conferred upon it by Congress. “If there is no statute conferring authority, a federal agency has none.” Section 112 of the Act is designed to limit HAP emissions from specific emission units that are listed under § 112(c)(1). EPA is required to promulgate “emissions standards under subsection (d)” for each category and subcategory listed under § 112(c)(1). The methodology for establishing emissions standards for each source category is laid out in § 112(d); it authorizes the Agency to promulgate “[e]missions standards...*applicable to new or existing sources.*” Under the final rule, the affected sources are “all existing industrial, commercial, and institutional boilers and process heaters” and “each new or reconstructed industrial, commercial, or institutional boiler or process heater.” A process heater is defined as “an enclosed device using controlled flame, and the unit’s primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material for use in a process unit, instead of generating steam.” A boiler is defined as “an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water.”

The affected source (*i.e.*, the process heater or boiler) clearly does not encompass the “boiler system” or “energy use systems” located at the major source. The fact that “including all of the energy using systems in the energy assessment can result in decreased fuel use” does not remedy this defect. For example, EPA’s definition of “boiler system” includes “the boiler *and associated components*, such as, the feedwater system, the combustion air system, the fuel system (including burners), blowdown system, combustion control system, and energy consuming systems.” Similarly, the “energy use system” includes “process heating; compressed air systems; machine drive (motors, pumps, fans); process cooling; facility heating, ventilation, and air conditioning systems; hot heater systems; building envelop; and lighting.” Both the “boiler system” and “energy use system” by definition include components outside the boiler and process heater. Accordingly, § 112 does not provide EPA with the authority to promulgate a requirement to conduct an energy assessment on energy use systems or parts of the “boiler system” that do not consist of the boiler or process heater, because such systems are not sources in the listed source category.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3449-A1, excerpt 32 for the definition of Energy Use Systems.

See the response to comment EPA-HQ-OAR-2002-0058-3427, excerpt 6 for energy assessment requirements for boilers and process heaters.

Commenter Name: Felix Mestey, on behalf of Donald R. Schregardus

Commenter Affiliation: Clean Air Act Services Steering Committee, Department of Defense (DoD)

Document Control Number: EPA-HQ-OAR-2002-0058-3427

Comment Excerpt Number: 4

Comment: EPA should consider excluding limited-use units from the energy assessment requirement, as their energy usage seems insignificant when compared to the energy used by all the other non-limited-use units. For example, in the case of Arnold AFB, the large limited-use process heaters have been historically used less than 200 hours per year. The fact that these units are only used for a relatively low number of hours per year would make the preparation of an energy assessment expensive with little environmental benefit (i.e., an insignificant decrease in HAP emissions). Revise §63.7500(c) and the "if your unit is..." column for requirement 4 in Table 3 to Subpart

DDDDD to clarify that the energy assessment is not applicable to limited-use units or small units as follows:

§63.7500 (c) Limited-use boilers and process heaters must complete a biennial tune-up as specified in § 63.7540. They are not subject to the emission limits in Tables 1 and 2 to this subpart, the annual tune-up or the energy assessment requirements in Table 3 to this subpart, or the operating limits in Table 4 to this subpart. ~~Major sources that have limited-use boilers and process heaters must complete an energy assessment as specified in Table 3 to this subpart if the source has other existing boilers subject to this subpart that are not limited use boilers.~~

(d) Boiler and process heaters systems with a rated capacity of less than 5 MMBtu/hr are not subject to the energy assessment requirement in Table 3 to this subpart.

Table 3 to Subpart DDDDD, "if your unit is..." column, requirement 4 as proposed: *An existing boiler or process heater located at a major source facility, except for limited-use units and units with a rated capacity of less than 5 MMBtu/hr.*

Response: See the response to comment EPA-HQ-OAR-2002-0058-3427, excerpt 6.

Commenter Name: Felix Mestey, on behalf of Donald R. Schregardus

Commenter Affiliation: Clean Air Act Services Steering Committee, Department of Defense (DoD)

Document Control Number: EPA-HQ-OAR-2002-0058-3427

Comment Excerpt Number: 5

Comment: Federal facilities, and in particular DoD installations, tend to be located on large tracts of land with numerous small buildings, which may be served by small boiler systems. For example, one AFB is located in three large counties, and has approximately 193 small units all with a capacity of less than 5 MMBtu/hr. Conducting an energy assessment for these boiler systems would be very time-consuming with little environmental benefit. These boilers at major sources are subject to tune-ups every 5 years regardless of fuel used. DoD recommends that smaller units be excluded from the energy assessment since each covered unit would likely require a site visit. The area source rule excludes units with a capacity of less than 10 MMBtu/hr from the energy assessment requirement. EPA should consider a similar exclusion in the major source rule, perhaps 5 MMBtu/hr, to improve the cost effectiveness of the energy assessment requirement.

Table 3 to Subpart DDDDD, "if your unit is..." column, requirement 4 as proposed: *An existing boiler or process heater located at a major source facility, except for limited-use units and units with a rated capacity of less than 5 MMBtu/hr.*

Response: See the response to comment EPA-HQ-OAR-2002-0058-3427, excerpt 6.

Commenter Name: Robert R. Perry
Commenter Affiliation: FirstEnergy Generation Corp (FGCO)
Document Control Number: EPA-HQ-OAR-2002-0058-3518-A1
Comment Excerpt Number: 5

Comment: We urge EPA to exempt "limited use" boilers from the energy assessment requirement. The energy assessment is projected by EPA to cost tens of thousands of dollars to complete. The ultimate impact on HAPs emissions, which EPA has already stated in most cases is either at or below the detection limit of the test method, will be miniscule.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3427, excerpt 6.

Commenter Name: Paul G. Page
Commenter Affiliation: AK Steel Corporation
Document Control Number: EPA-HQ-OAR-2002-0058-3457-A2
Comment Excerpt Number: 15

Comment: AK Steel remains uncertain as to what EPA's expectations are for the Energy Assessment. Specifically, AK Steel is unclear as to how these assessments are to be performed and what is supposed to be achieved. For example, one of our facilities is subject to this requirement based on a natural gas-fired process heater in a coating line operation being the only affected source. EPA needs to further clarify the Energy Assessment requirements for this facility, if these requirements remain in the final rule, because we see no valid reason to conduct an energy assessment for a coating line process heater nor do we see a valid reason to conduct a facility-wide energy assessment because the facility is subject to the rule as a result of a process heater.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3427, excerpt 6.

Commenter Name: Alicia Meads
Commenter Affiliation: National Association of Manufacturers (NAM)
Document Control Number: EPA-HQ-OAR-2002-0058-3515-A1
Comment Excerpt Number: 18

Comment: The NAM continues to believe that the EPA's proposed energy assessment requirements are unwarranted. Further, although the EPA has indicated that it is limiting the scope of its energy assessment requirements, the NAM believes that the measures still exceed the scope of the EPA's authority. Section 112(d) of the Clean Air Act is focused entirely on regulation of "sources." It requires the EPA to set emissions standards that are "applicable to new or existing sources" § 112(d)(2). Thus, it reaches no further than the specific "sources." The "affected source" regulated by this NESHAP is the specified emission unit – boilers – not any

other portions of the plant. Thus, if the EPA retains the energy assessment requirements, they should be clearly limited to addressing only the boiler and auxiliaries.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3427, excerpt 6.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 80

Comment: The definition of energy assessment proposed in this reconsideration, while improved from the language in the Final Boiler Rule, continues to be too broad because it appears to establish obligations beyond the boiler or process heater source. The rule states that an energy assessment, or audit, is an in-depth energy study identifying all energy conservation measures appropriate for a facility given its operating parameters. It leads to the reduction of emissions of pollutants through process changes and other efficiency modifications. The purpose of an energy assessment is to identify energy conservation measures (such as process changes or other modifications to the facility) that can be implemented to reduce the facility energy demand which would result in reduced fuel use. EPA is requiring that the energy assessment be conducted by energy professionals and/or engineers that have expertise that covers all energy using systems, processes, and equipment. The broad definition of the scope of an energy assessment is unreasonable. The language attempts to include equipment and systems far beyond the intent of the "Industrial, Commercial and Institutional Boilers and Process Heaters" rule. In its definitions, EPA correctly defines a "Boiler" and a "Process heater" to refer to enclosed devices containing a controlled flame that are used to recover heat. However, EPA attempts to vastly expand the scope of this rule in its definition of a "Boiler system" by including the term "energy use systems." This expansion in scope is reinforced in EPA's choice of language describing the scope of energy assessments to include modifications to the facility. The expansion in scope is further reinforced by implication that those conducting the energy assessments should have expertise that covers all energy using systems.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3427, excerpt 6 and comment EPA-HQ-OAR-2002-0058-3449-A1, excerpt 32.

Commenter Name: Eric Guelker, Alliant Energy Corporate Services, Inc.

Commenter Affiliation: Interstate Power and Light Company (IPL) and Wisconsin Power and Light Company (WPL), Alliant Energy Corp.

Document Control Number: EPA-HQ-OAR-2002-0058-3492-A1

Comment Excerpt Number: 14

Comment: Short of completely removing these requirements, we recommend that EPA adopt a de minimis exemption for the energy assessment requirement that would remove its applicability for all units less than 10 mmBtu/hr and limited use units.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3427, excerpt 6.

Commenter Name: Kevin G. Desharnais, Attorney, Mayer Brown LLP
Commenter Affiliation: United States Sugar Corporation
Document Control Number: EPA-HQ-OAR-2002-0058-3496-A1
Comment Excerpt Number: 4

Comment: While the energy assessment requirement should be eliminated in its entirety, to the extent the requirement is retained, the scope of the assessment as currently proposed remains significantly overbroad, potentially encompassing every energy-using piece of equipment at a regulated facility. The scope of the energy assessment as currently proposed extends far beyond the reasonable limits of what is properly considered the regulated source, *i.e.*, the regulated boiler or process heater. This attempt to expand the reach of the NESHAP regulations to such a wide array of equipment is well beyond EPA's authority to regulate hazardous air pollutants under the Section 112 rulemaking process. Any requirement to perform an energy assessment should be limited to the regulated source.

EPA should reconsider its mandatory energy assessment and eliminate the provision. To the extent the requirement to perform an energy assessment is retained, the scope of the energy assessment should be limited to the boiler or process heater constituting the regulated source.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3427, excerpt 6.

Commenter Name: Timothy Serie
Commenter Affiliation: American Coatings Association (ACA)
Document Control Number: EPA-HQ-OAR-2002-0058-3502-A1
Comment Excerpt Number: 17

Comment: ACA generally supports the following proposed changes to the MACT and area source boiler rules: MACT – EPA clarification that the scope of the energy assessments is to be limited to those facilities and equipment associated with the energy output from the regulated boilers and process heaters. ACA suggests that EPA should eliminate the definitions of “boiler system” and “energy use system” and further limit the scope of energy assessments to “boiler(s)” and “process heater(s)” as currently defined;

Response: See the response to comment EPA-HQ-OAR-2002-0058-3427, excerpt 6.

Commenter Name: Richard Krock
Commenter Affiliation: The Vinyl Institute
Document Control Number: EPA-HQ-OAR-2002-0058-3526-A1
Comment Excerpt Number: 23

Comment: While the proposed rule is clear that boilers and process heaters regulated under another MACT standard are not subject to Subpart DDDDD, including the energy assessment requirement, it is not clear that an energy use system that is regulated under another MACT standard is not subject to the energy assessment requirement. From a practical standpoint, there is nothing to gain by including such energy use systems in the energy assessment, because these energy use systems will be, in most cases, specifically engineered to comply with the other

MACT standard and cannot be improved or altered without affecting compliance. In the interest of clarity and consistency, the VI requests that EPA revise the energy assessment requirement to clearly exempt these energy use systems.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3427, excerpt 6.

Commenter Name: Lisa Barry

Commenter Affiliation: Chevron Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3687-A2

Comment Excerpt Number: 5

Comment: EPA is vastly expanding the scope of this rule in its definition of "boiler system" to include "energy use systems." Energy use in most manufacturing plants is related to the processes being used. The sweeping language exceeds EPA's authority by essentially requiring an evaluation and potential redesign of manufacturing systems, many of which are proprietary. Also, energy assessment and management system regulations are excessively costly and burdensome for the little air toxic benefit that will result, especially for gas-fired units. However, if EPA proceeds with this requirement, it must limit the scope of energy assessments to "boilers" and "process heaters" as currently defined.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3427, excerpt 6.

Commenter Name: Shawn Good

Commenter Affiliation: Pennsylvania Chamber of Business and Industry

Document Control Number: EPA-HQ-OAR-2002-0058-3671-A2

Comment Excerpt Number: 6

Comment: EPA should clarify that required energy assessments are limited to the regulated boiler/unit, and are not applicable to the entire facility.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3427, excerpt 6.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 114

Comment: If EPA continues with this broad scope of coverage for the energy assessment, further clarification is required to limit the scope of effort relative to the percent of affected boiler(s) and process heater(s) energy output for different size facilities. Specifically, it is unclear how the percentages in the Energy assessment definition are to be applied. CIBO believes that EPA's intentions are to limit the scope of assessment based on energy use by discrete segments of a facility, and not by a total aggregation of all individual energy using elements of a facility, because the latter would be disjointed and unwieldy at best. The applicable discrete segments of a facility could vary significantly depending on the site and its complexity. However, CIBO believes the following addition to the Energy assessment definition in 63.7575 would help resolve current problems and allow for more streamlined assessments:

"(4) the on-site energy use systems serving as the basis for the percent of affected boiler(s) and process heater(s) energy output in (1), (2), and (3) above may be segmented by production area or energy use area as most logical and applicable to the specific facility being assessed (e.g., product X manufacturing area; product Y drying area; building Z)."

Response: See the response to comment EPA-HQ-OAR-2002-0058-3668-A2, excerpt 20.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 83

Comment: If EPA continues with this broad scope of coverage for the energy assessment, further clarification is required to limit the scope of effort relative to the percent of affected boiler(s) and process heater(s) energy output for different size facilities. Specifically, it is unclear how the percentages in the energy assessment definition are to be applied. ACC believes that EPA's intentions are to limit the scope of assessment based on energy use by discrete segments of a facility, and not by a total aggregation of all individual energy using elements of a facility, because the latter would be disjointed and unwieldy at best. The applicable discrete segments of a facility could vary significantly depending on the site and its complexity. However, ACC believes the following addition to the energy assessment definition in § 63.7575 would help resolve current problems and allow for more streamlined assessments:

"...(4) The on-site energy use systems serving as the basis for the percent of affected boiler(s) and process heater(s) energy output in (1), (2), and (3) above may be segmented by production area or energy use area as most logical and applicable to the specific facility being assessed (e.g., product X manufacturing area; product Y drying area; Building Z)."

Response: See the response to comment EPA-HQ-OAR-2002-0058-3668-A2, excerpt 20.

Commenter Name: Bruce A. Steiner

Commenter Affiliation: American Coke and Coal Chemical Institute (ACCCI)

Document Control Number: EPA-HQ-OAR-2002-0058-3547-A2

Comment Excerpt Number: 12

Comment: EPA cannot impose requirements that reach beyond the defined source category. Section 112(c) establishes the scope of regulation under §112 by requiring EPA to publish "a list of all categories and subcategories of major sources and area sources" for which "the Administrator shall establish emissions standards under subsection (d)." CAA §§112(c)(1) and (2), respectively. Pursuant to that requirement, EPA published a discrete list of major and area source categories. See 70 FR at 37824; see also 67 FR at 70428. Thus, that list of source categories sets both the maximum and minimum scope of EPA's regulatory authority to "establish emissions standards under subsection (d)."

The Reconsidered Rule explicitly states that the source categories affected by these rules are industrial, institutional, and commercial boilers and process heaters located at a major source. Section 112 does not authorize EPA to promulgate regulations affecting sources beyond those

specifically listed. Rather, as the legislative history confirms, “MACT standards shall be focused on a specific portion of a contiguous facility.... The entity covered by MACT would be defined at proposal of the standards.” (emphasis added). A Legislative History of the Clean Air Act Amendments of 1990, 1990 CAA Leg. Hist. 731, 866. Thus, this rulemaking under CAA §112(d) only extends to the “specific portion” of the facilities identified in EPA’s list under §112(c) and can go no further.

Response: We disagree that the energy assessment should be limited to only the boiler and associated equipment. The EPA has properly exercised the authority granted to it pursuant to CAA section 112(d)(2) which states that “Emission standards promulgated * * * and applicable to new or existing sources shall require the maximum degree of reduction in [HAP] emissions that the Administrator determines * * * is achievable * * * through application of measures, processes, methods, systems or techniques including, but not limited to measures which * * * reduce the volume of, or eliminate emissions of, such pollutants through process changes, substitution of materials or other modifications * * *.” The energy assessment requirement is squarely within the scope of this authority. The purpose of an energy assessment is to identify energy conservation measures (such as process changes or other modifications to the facility) that can be implemented to reduce the facility energy demand from the affected boiler, which would result in reduced fuel use. Reduced fuel use will result in a corresponding reduction in HAP, and non-HAP, emissions from the affected boiler.**Commenter Name:** Shannon S. Broome
Commenter Affiliation: Auto Industry Forum (AIF)
Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1
Comment Excerpt Number: 48

Comment: As conveyed in the reconsideration proposal, the energy assessment requirement creates uncertainty in the regulated community, including AIF members, as to how to effectuate it, including with respect to the following issues:

- Are facilities supposed to conduct the assessment as to individual boilers or as to the facility as a whole? The reconsideration proposal appears to suggest that facilities should conduct the assessment on an individual boiler basis; however, Table 3 creates confusion as to the scope because it mixes references to boilers and process heaters in the singular and the collective, and it refers to the assessment being conducted "on" the facility as opposed to "at" the facility.³² *Id.* at 80,664.

[Footnote 32: Moreover, Table 3, in listing the requirements of the assessment, refers to an evaluation of the "specification of *energy using systems*," *id.*, 76 Fed. Reg. at 80,664 (emphasis added), which is an undefined term, although it is similar to the defined term, "energy use systems." EPA should clarify what it means by the phrase, "energy using systems" or revise the phrase to refer to the defined term "energy use systems."

Response: See the response to comment EPA-HQ-OAR-2002-0058-3668-A2, excerpt 20.

Commenter Name: Vickie Woods
Commenter Affiliation: Division of Air Quality, North Carolina Department of Environment and Natural Resources (NCDENR)
Document Control Number: EPA-HQ-OAR-2002-0058-3663-A2
Comment Excerpt Number: 20

Comment: EA Scope pertains to boiler, and not facility-wide.

NC DAQ concurs with this clarification. However, NC DAQ also recognizes the advantages that facilities may gain from facility-wide energy assessments by examining where and how energy efficiency measures may reduce overall energy requirements and overall emissions.

Response: The EPA thanks the commenter for their support.

Commenter Name: Michael Bradley

Commenter Affiliation: The Clean Energy Group

Document Control Number: EPA-HQ-OAR-2002-0058-3495-A1

Comment Excerpt Number: 2

Comment: The Clean Energy Group has long agreed that promoting efficiency is a key emissions-reduction strategy across a wide variety of pollutants, including HAPs. However, not clearly defining the scope of the assessment could inadvertently apply the requirement to the entire facility and unrelated systems, which would be complicated, time-consuming, and likely involve equipment outside EPA's NESHAP jurisdiction (such as at nuclear facilities). Therefore, in our comments on the proposed rules, we requested that EPA clarify that the process for and scope of the energy assessment is limited to the boiler unit and associated systems and controls, and does not include an in-depth assessment of the entire facility and unrelated systems. We support EPA's proposed revisions to clarify the scope of the assessment to ensure it is not overly broad.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3668-A2, excerpt 20.

Commenter Name: Holly R. Hart

Commenter Affiliation: United Steel Workers (USW)

Document Control Number: EPA-HQ-OAR-2002-0058-3498-A1

Comment Excerpt Number: 6

Comment: USW notes EPA now proposes as described at page 80602 that for each affected boiler the operator will have to comply with a beyond-the-floor requirement of a onetime energy assessment. Also noted is that EPA is proposing as described at page 80602 a systematic set of definitions of the requirements operators of eligible units will need to meet to be in compliance with the work practice standards proposed.

Response: The term "operator" as used in the rule, refers to the company that owns or operate the facility, and not to the individual actually operating the piece of equipment.

Commenter Name: Bruce W. Ramme

Commenter Affiliation: Wisconsin Electric Power Company (WE Energies)

Document Control Number: EPA-HQ-OAR-2002-0058-3452-A1

Comment Excerpt Number: 6

Comment: We Energies supports EPA's proposal to clarify its intent and narrow the scope of the requirement for a "one-time" energy assessment to apply to IB-MACT affected sources only.

Response: The EPA thanks the commenter for their support.

Commenter Name: Timothy Serie

Commenter Affiliation: American Coatings Association (ACA)

Document Control Number: EPA-HQ-OAR-2002-0058-3502-A1

Comment Excerpt Number: 19

Comment: ACA generally supports the following proposed changes to the MACT and area source boiler rules: MACT and Area Source – EPA clarification that it did not intend to include in the energy assessment energy use systems using electricity purchased from an off-site source, nor include energy use systems located off-site;

Response: See the response to comment EPA-HQ-OAR-2002-0058-3501-A1, excerpt 12.

Commenter Name: Pat Dennis

Commenter Affiliation: Archer Daniels Midland Company

Document Control Number: EPA-HQ-OAR-2002-0058-3670-A2

Comment Excerpt Number: 12

Comment: While the scope of the covered energy use systems should certainly be narrowed, EPA's proposed exclusion of systems that run on purchased power creates an arbitrary distinction among efficiency measures at a facility based on the source of power. There is no logic to requiring a more reaching assessment of energy systems by sources that depend more heavily upon power produced onsite than by sources that purchase power. In addition, it is not always apparent what the source of the power is for any individual energy-consuming system at a facility. As EPA has made clear, the goal is to reduce the facility energy demand which would result in reduced fuel use. While ADM supports EPA's narrowing the scope of the energy assessment, the current definition remains over-broad and lacking in record support and legal authority.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3547-A2, excerpt 12.

Commenter Name: David A. Buff, Golder Associates Inc.

Commenter Affiliation: Florida Sugar Industry (FSI)

Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1

Comment Excerpt Number: 46

Comment: The FSI also respectfully requests EPA to clarify what the operator is obligated to do after the energy assessment is completed. Specifically, EPA should confirm that a facility owner or operator is not obligated to implement any of the recommendations contained in the energy assessment report. At present, the Proposed Boiler MACT Rule requires the preparation of a report and recommendations, but the Proposed Boiler MACT Rule does not state whether any of the recommendations must be implemented. See Table 3 at 76 F.R. 80664.

Response: The rule does not state, or imply, that the findings of the energy assessment must be implemented. However, EPA expects that facilities will implement most or all of the measures identified in the energy assessment, based on the cost savings that will result from implementing

those measures. The rule does allow in 63.7533 a source to take credit for implementing any measures identified in an energy assessment if the source elects to comply with the alternative output-based emission limits.

Commenter Name: Jennifer Youngblood

Commenter Affiliation: National Tribal Air Association

Document Control Number: EPA-HQ-OAR-2002-0058-3667-A2

Comment Excerpt Number: 2

Comment: If the energy assessment is finalized, energy assessor qualification requirements must be generalized. Proposed §63.7575 defines qualified energy assessor as follows.

Qualified Energy Assessor means:

(1) Someone who has demonstrated capabilities to evaluate energy savings opportunities for steam generation and major energy using systems, including, but not limited to:

(i) Boiler combustion management.

(ii) Boiler thermal energy recovery, including

(A) Conventional feed water economizer.

(B) Conventional combustion air preheater, and

(C) Condensing economizer.

(iii) Boiler blowdown thermal energy recovery.

(iv) Primary energy resource selection, including

(A) Fuel (primary energy source) switching, and

(B) Applied steam energy versus direct-fired energy versus electricity.

(v) Insulation issues.

(vi) Steam trap and steam leak management.

(vii) Condensate recovery.

(viii) Steam end-use management.

(2) Capabilities and knowledge includes, but is not limited to:

(i) Background, experience, and recognized abilities to perform the assessment activities, data analysis, and report preparation.

(ii) Familiarity with operating and maintenance practices for steam or process heating systems.

(iii) Additional potential steam system improvement opportunities including improving steam turbine operations and reducing steam demand.

(iv) Additional process heating system opportunities including effective utilization of waste heat and use of proper process heating methods.

(v) Boiler-steam turbine cogeneration systems.

(vi) Industry specific steam end-use systems.

There are at least two major problems with this definition. First, as written, this definition requires a single person to have all of the capabilities and experience listed. Such a person likely does not exist. For instance, people who specialize in boiler combustion management will likely have no experience with condensate recovery or industry specific steam end use systems. If instead of a single person, the definition is meant to apply to a team (as most energy assessments require) that is not reflected in the time, burden or cost estimates used for this rule. Secondly, the definition requires expertise and experience that will not be needed for most assessments. For instance, most facilities do not have boiler-steam turbine cogeneration systems, yet under this definition they cannot employ an assessor who lacks that experience. Similarly, the definition requires a boiler expert even if only process heaters (or mostly process heaters) are to be assessed and a process heater expert even if the facility only has boilers.

The wording of the proposed definition is also unclear that the qualified energy assessor(s) may be a company employee. Many companies employ specialists in combustion who have the appropriate expertise and we believe it is critical that the definition be clear that those employees may serve in this function.

Since every facility is different and every engineer's experience is different, it is impractical, arbitrary, and unreasonable to list specific experience and training requirements. We therefore, recommend the definition of qualified energy assessor be revised to the following.

Qualified Energy Assessor or Assessors means a person or persons who have demonstrated capabilities to evaluate energy savings opportunities for steam generation, process heat, and major steam and process heat using systems, as applicable to the facility. Qualified energy assessors may be company employees or outside specialists.

Response: We disagree that the definition of "Qualified energy assessor" is unclear and needs clarification. We realize that every facility is different and that it is impractical to require a single person to have all of the capabilities and experience listed to conduct an assessment of a simple heating boiler system. The term "Someone" is not intent to mean a single person. For more complicated boiler/energy use systems or facilities with multiple boilers, a group, such as a consulting firm or a company's engineering staff, with the needed expertise could perform the required engineering assessment. The definition is intended to indicate that the "someone" a facility employs to conduct the energy assessment should have the background, experience, and expertise to evaluate energy savings opportunities for the types of boiler/energy use systems located at the particular facility. The definition is not intended to imply that the any energy assessment, no matter how simple, can only be conducted by a person with expertise in all the issues listed in the definition. Basically, the definition is stating that a person is qualified to conduct an energy assessment if they have the needed experience and background in conducting

an energy assessment for a particular situation. For a particular boiler/energy system, a company employee may have the background, experience, and abilities to perform the assessment and prepare the report.

Commenter Name: Jennifer Youngblood

Commenter Affiliation: National Tribal Air Association

Document Control Number: EPA-HQ-OAR-2002-0058-3667-A2

Comment Excerpt Number: 3

Comment: If the energy assessment requirement is finalized, the Table 3 Item 4 allowance for use of past energy assessments, must be amended to waive energy assessor approval and qualifications requirements.

Proposed Item 4 of Table 3 lists the elements that must be addressed in the energy assessment. In the introductory paragraph it states "An energy assessment completed on or after January 1, 2008, that meets or is amended to meet the energy assessment requirements in this table, satisfies the energy assessment requirement." However, to be acceptable an energy assessment must have been performed by an assessor approved by the Administrator and that assessor or team of assessors must have met all of the requirements in the proposed qualified energy assessor definition. As discussed in the previous comment, the energy assessor definition is unreasonably restrictive and it is virtually impossible that an existing assessment was done by a team that met all those specific requirements. Further, the assessor or assessors for a past assessment certainly were not approved by the Administrator. Thus, the allowance to use existing assessments, which we requested and fully support, is not usable in practice. A sentence needs to be added to Table 3 Item 4 that waives the energy assessor definition and approval where an existing assessment is being used to meet the energy assessment requirement.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3667-A2, excerpt 2.

Commenter Name: Jennifer Youngblood

Commenter Affiliation: National Tribal Air Association

Document Control Number: EPA-HQ-OAR-2002-0058-3667-A2

Comment Excerpt Number: 6

Comment: The definition of energy assessment is unclear whether the energy assessment applies to just boilers or to both boilers and process heaters. Since the size criterion (i.e., the facility boiler and process heater energy consumption) is based on both boilers and process heaters, we assume the assessment must deal with both steam and process heat. The energy assessment definition wording, as exemplified in Item 4 below, should be clarified on this point.

The definition of energy assessment has three categories based on facility heat input, but then requires that the assessment address "energy use systems." There is no basis for expanding the assessment beyond producers and users of steam or heat provided by boilers and process heaters subject to this rule (e.g., electricity users, imported steam users) and therefore the term "energy system" should be replaced with "steam and process heat consumers."

Each of the three paragraphs in the energy assessment definition call for evaluating “the boiler system and any energy use system” accounting for at least a specified percentage of the energy output. As in the previous item, the term “energy” is unclear and should be changed to “steam or process heat.” Additionally “output” is a meaningless term related to consumers and that word should be changed to “production or consumption.” Finally, it should be clarified the percent is the percent of the facility total steam and process heat production or consumption, as applicable.

For example, to address the above concerns, Paragraph 3 of the energy assessment definition should be revised to read as follows.

(3) In the Energy assessment for facilities with affected boilers and process heaters using greater than 1.0 trillion Btu per year, the boiler system, **process heater**, and any **energysteam or process heat** use system accounting for at least 20 percent of the **energysteam or process heat** ~~output~~**production or consumption, as applicable, at the facility** will be evaluated to identify **energysteam or process heat** savings opportunities.

Similar revisions to Paragraphs 1 and 2 of the energy assessment definition are also needed.

Response: We agree that definition of "energy assessment" needs clarification. Based on the various comments and suggested wordings, we have revised the definition to better clarify the intent and cope of the energy assessment. We have added, as suggested, "process heater" and "(e.g., steam, process heat, hot water, or electricity)" after energy, since there are several forms of energy that may be produced, to better define the "output."

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 111

Comment: The definition of energy assessment is too broad because it appears to establish obligations beyond the boiler or process heater source. The rule in relevant part states that an energy assessment, or audit, is an in-depth energy study identifying all energy conservation measures appropriate for a facility given its operating parameters. It leads to the reduction of emissions of pollutants through process changes and other efficiency modifications. The purpose of an energy assessment is to identify energy conservation measures (such as, process changes or other modifications to the facility) that can be implemented to reduce the facility energy demand which would result in reduced fuel use. EPA is requiring that the energy assessment be conducted by energy professionals and/or engineers that have expertise that covers all energy using systems, processes, and equipment.

The broad definition of the scope of an energy assessment is unreasonable. The language attempts to include equipment and systems far beyond the intent of the "Industrial, Commercial and Institutional Boilers and Process Heaters" rule. In its definitions, EPA correctly defines a "boiler" and a "process heater" to refer to enclosed devices containing a controlled flame that are used to recover heat. However, EPA attempts to vastly expand the scope of this rule in its definition of a "boiler system" by including the term "energy use systems". This expansion in scope is reinforced in EPA's choice of language describing the scope of energy assessments to include modifications to the facility. The expansion in scope is further reinforced by implication

that those conducting the energy assessments should have expertise that covers all energy using systems.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3667-A2, excerpt 6 and comment EPA-HQ-OAR-2002-0058-3449-A1, excerpt 32.

Commenter Name: Timothy Serie

Commenter Affiliation: American Coatings Association (ACA)

Document Control Number: EPA-HQ-OAR-2002-0058-3502-A1

Comment Excerpt Number: 22

Comment: ACA generally supports the following proposed changes to the MACT and area source boiler rules: MACT and Area Source – EPA clarification that the assessment does not need to be submitted to EPA but may be kept onsite.

Response: The EPA thanks the commenter for their support.

Commenter Name: Shannon S. Broome

Commenter Affiliation: Auto Industry Forum (AIF)

Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1

Comment Excerpt Number: 46

Comment: *Boiler MACT Reconsideration Proposal*, 76 Fed. Reg. at 80,664; *see also id.* at 80,614-15 (relevant discussion in the preamble). EPA also proposes adding clarifying language to § 63.7510's initial compliance requirements to the effect that existing affecting sources must "complete the one-time energy assessment specified in Table 3 to this subpart ... no later than the compliance date specified in § 63.7495,"³¹ *i.e.*, no later than 3 years after publication of the final reconsideration rule. *Id.* at 80,631.

To the extent that the Agency retains the assessment in the final reconsideration rule, AIF supports the clarification that the assessment does not include energy use systems using electricity purchased from an offsite source or energy use systems located offsite and urges EPA to place this clarification in the final reconsideration rule itself, not just in the preamble. The regulations themselves must clarify the scope of the assessment.

Response: The EPA thanks the commenter for their support of the proposed clarification to limit the energy assessment to on-site energy use systems.

Commenter Name: Richard Krock

Commenter Affiliation: The Vinyl Institute

Document Control Number: EPA-HQ-OAR-2002-0058-3526-A1

Comment Excerpt Number: 22

Comment: EPA Should Clarify the Scope of the Energy Assessment for Certain Equipment

The VI supports EPA's proposed revisions to the energy assessment requirement, which limit the energy assessment to the boiler system and the energy use system. EPA proposed thresholds for

including a given energy use system (e.g., process heating or cooling, lighting, compressed air) in the energy assessment. Specifically, the energy system must use at least 20 percent of the energy output—if the sum total energy consumption of the affected boilers and process heaters is greater than 1.0 trillion Btu per year; the threshold increases for affected boilers and process heaters that use less energy per year—to be a required part of the energy assessment.

EPA should clarify that the energy assessment requirement does not extend to equipment regulated under other MACT standards. The proposed rule states,

The types of boilers and process heaters listed in paragraphs (a) through (n) of this section are not subject to this subpart . . .

(h) Any boiler or process heater that is part of the affected source subject to another subpart of this part (i.e., another National Emission Standards for Hazardous Air Pollutants in 40 CFR part 63).

Response: We agree that boilers and process heaters that are not subject to the rule are not included in the energy assessment. We have made revisions to the various energy assessment requirements to make clear that only affected boilers and process heaters are to be included. See the response to comment EPA-HQ-OAR-2002-0058-3427, excerpt 6.

Commenter Name: Michael Bradley

Commenter Affiliation: The Clean Energy Group

Document Control Number: EPA-HQ-OAR-2002-0058-3495-A1

Comment Excerpt Number: 4

Comment: Separately, in our comments on the proposed rule, we recommended including the option to certify internal annual or continuous efficiency monitoring programs as equivalent to the energy assessments proposed if they offer similar or greater opportunities to identify potential efficiency gains to ensure this provision does not displace more intensive or regular assessments that may already occur. We appreciate EPA including this recommendation in the final rule and support maintaining this option after the reconsideration.

Response: The EPA thanks the commenter for their support.

5B. Compliance Date

Commenter Name: Jessica Bridges

Commenter Affiliation: United States Clean Heat & Power Association (USCHPA)

Document Control Number: EPA-HQ-OAR-2002-0058-3501-A1

Comment Excerpt Number: 15

Comment: EPA now proposes that the Energy Assessment for existing sources be completed by the reset compliance date. We appreciate resetting the compliance date for existing sources to three years from the date of publication of the final reconsideration rule and for new sources (new after June 4, 2010) to 60 days after the date of publication of the final reconsideration rule or upon startup, whichever is later.

Response: The EPA thanks the commenter for their support.

Commenter Name: Timothy Serie

Commenter Affiliation: American Coatings Association (ACA)

Document Control Number: EPA-HQ-OAR-2002-0058-3502-A1

Comment Excerpt Number: 20

Comment: ACA generally supports the following proposed changes to the MACT and area source boiler rules: MACT and Area Source – EPA clarification that energy assessments must be completed by the compliance date;

Response: The EPA thanks the commenter for their support.

5C. Maximum Duration

Commenter Name: Claudia M. O'Brien, Latham & Watkins LLP

Commenter Affiliation: JELD-WEN, inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3485-A1

Comment Excerpt Number: 3

Comment: In the Boiler MACT reconsideration, EPA has proposed to revise its "Energy assessment" requirement to change the maximum duration for performing the assessment. The final rule had established a maximum duration of three days for affected boilers and process heaters using 0.3 to 1 TBtu/year. JELD-WEN and other commenters explained that the assessment required by EPA could take longer than that time. In response, EPA has proposed to revise the energy assessment duration to a maximum of 24 technical hours to allow sources to perform longer assessments "at their discretion." JELD-WEN supports this revision. Since the Boiler MACT rule establishes an exhaustive list of items that need to be evaluated during the energy assessment, JELD-WEN agrees that sources should have discretion to perform longer assessments to properly address all of the items required by the rule. JELD-WEN also supports EPA's decision not to set a mandatory minimum amount of time for the assessment, agreeing with EPA's intent to "minimize the burden" for facilities that can perform the assessment in a shorter period of time.

Response: The EPA thanks the commenter for their support.

Commenter Name: Timothy Serie

Commenter Affiliation: American Coatings Association (ACA)

Document Control Number: EPA-HQ-OAR-2002-0058-3502-A1

Comment Excerpt Number: 21

Comment: ACA generally supports the following proposed changes to the MACT and area source boiler rules: MACT and Area Source – EPA proposal changing the maximum duration requirements from one day to eight technical hours, and three days to 24 technical hours to limit the time/effort of an outside energy assessor to perform the energy assessment;

Response: The EPA thanks the commenter for their support.

Commenter Name: Michael L. Krancer
Commenter Affiliation: Pennsylvania Department of Environmental Protection (DEP)
Document Control Number: EPA-HQ-OAR-2002-0058-3507-A1
Comment Excerpt Number: 17

Comment: The EPA has revised the definition of "Energy assessment" to change the maximum time from one day to eight technical hours and from three days to 24 technical hours and to allow sources to perform longer assessment at their discretion. EPA's intent for including "maximum time" in the final rule definition was to minimize the burden on the smaller fuel-use facilities, many of which are likely small entities, by limiting the extent of the energy assessment. EPA's concern was that if there was no time limit, then the small facilities would have no means to limit the time and effort of an outside energy assessor that is contracted to perform the energy assessment. The EPA has made other revisions to the definition of "Energy assessment" to better clarify its intent. The DEP agrees with the clarifying revisions to the definition of "Energy assessment."

Response: The EPA thanks the commenter for their support.

Commenter Name: Bill Wilson
Commenter Affiliation: Washington State University
Document Control Number: EPA-HQ-OAR-2002-0058-3786-A1
Comment Excerpt Number: 2

Comment: A maximum of 8 technical labor hours are prescribed for assessments in facilities with affected boilers and process heaters with annual energy consumption of less than 0.3 trillion Btu annually. A maximum of 24 technical labor hours are prescribed for boilers and process heaters with annual energy consumption from 0.3 to 1.0 trillion Btu annually. No maximum hours are prescribed for systems with annual energy consumption greater than 1.0 trillion Btu. For the two lower annual energy use brackets, a statement about optional additional time is provided.

I believe the prescribed hours for the two lower annual energy use brackets are inadequate for conducting the full energy assessment process in a manner which successfully fulfills the energy assessment criteria and outcomes listed in Table 3 – To Subpart DDDDD of Part 63 – Work Practice Standards, Items 4a – 4f. The 8 hour maximum for the lowest annual energy use bracket is woefully inadequate, and I believe will raise unrealistic expectations by those seeking energy assessment expertise. I would also like to point out energy assessment is only technical service described in the Final Rule Reconsideration in which hours to perform a task have been prescribed. Other technical services like burner tuning, stack testing, etc. do not have labor time limits prescribed.

Response: As indicated in the final, EPA's intent for including "maximum time" in the definition was to minimize the burden on the smaller fuel-use facilities, many of which are likely small entities, by limiting the extent of the energy assessment. EPA's concern was that if there was no time limit, then the small facilities would have no means to limit the time and effort of an outside energy assessor that is contracted to perform the energy assessment. However, the energy assessment can be longer at the owner discretion. The final rule definition has been revised to

clarify that the technical hours are "on-site" technical hours to conduct the evaluation of the boiler or process heater and its energy using systems, and does not include the off-site effort to prepare the report.

Commenter Name: Bill Wilson

Commenter Affiliation: Washington State University

Document Control Number: EPA-HQ-OAR-2002-0058-3786-A1

Comment Excerpt Number: 3

Comment: In my experience, the amount of pre-assessment time devoted making arrangements and obtaining information, on-site observation time and post-assessment analysis and report generation time expenditure is quite independent of unit maximum heat input ratings or system annual energy consumption. My experience has been no less than 24 hours of on-site time is typically required with very a very considerable amount of pre-assessment and post-assessment time involvement required. The stated time does not include time expenditures required by facility personnel. 24 hours (3 days) also the approximate on-site time allotted to assessors performing UDOE steam system and process heating SEN assessments. Significant additional time is allotted for preliminary tasks and reporting and follow-up activities.

I feel the prescriptive technical labor hour statements should be eliminated entirely. The Energy Assessment requirement was introduced presumably for identifying and quantifying opportunities which could, if implemented, reduce energy consumption and emissions. This outcome will not likely be realized, especially for smaller facilities, with the severe time restrictions prescribed.

Response: We disagree, see the response to comment EPA-HQ-OAR-2002-0058-3786-A1, excerpt 2.

Commenter Name: Jennifer Youngblood

Commenter Affiliation: National Tribal Air Association

Document Control Number: EPA-HQ-OAR-2002-0058-3667-A2

Comment Excerpt Number: 1

Comment: The revisions to the definition of "energy assessment" to allow EPA to incorrectly claim a reduced energy assessment cost do not accomplish that goal and the true cost should be reflected in the beyond-the-floor analysis and the Information Collection Request or EPA must change the energy assessment requirements to match the time allowed.

On page 80615 of the proposal preamble EPA states; "We have revised the definition of "energy assessment" to change the maximum time from 1 day to 8 technical hours and from three days to 24 technical hours. This would allow sources to perform longer assessments at their discretion." All this change does is revise the criterion for when the violation occurs (i.e., it is now a violation if you fail to meet all the energy assessment criteria in Table 3 because to do so would require more than 8 hours or 24 hours, rather than 1 day or 3 days.). Nothing in the proposed energy assessment definition relieves sources from the Table 3 requirements for energy assessment content if they cannot complete the assessment in the specified time. In fact, proposed §63.7530(e) requires that a facility certify in the NCS that "the energy

Since sources have no discretion whether or not to spend more time, it is false for EPA to assume the 8 and 24 hour limits have any meaning or to rely on those limits for the burden and cost analyses. Therefore, the cost estimates should be revised for the major and area source rules to reflect the full costs of this requirement (and the extra personnel costs needed to meet the definition of qualified energy assessor, as discussed in our next comment).

Response: We agree that the wording in Table 3 could be interpreted to require a complete energy assessment regardless of the maximum technical hours listed in the definition of "Energy assessment." That was not our intent. Item 4 of Table 3 has been revised to include: "The energy assessment must include the following with extent of the evaluation for items a. to e. appropriate for the on-site technical hours listed in §63.7575."

Commenter Name: Jennifer Youngblood

Commenter Affiliation: National Tribal Air Association

Document Control Number: EPA-HQ-OAR-2002-0058-3667-A2

Comment Excerpt Number: 4

Comment: Proposed §63.7545(e)(8)(ii) requires that the NCS certify that "This facility has had an energy assessment performed according to § 63.7530(e)." The referenced §63.7530(e) requires that a facility certify in the NCS that "the energy assessment was completed according to Table 3 to this subpart and is an accurate depiction of your facility." If the 8 hour and 24 hour limits on the energy assessment for facilities producing < 1 trillion BTU/year are made meaningful, most sources in those production ranges will not have completed energy assessments, since that amount of time is inadequate to even get started. Thus, those sources will be unable to sign the proposed certification wording. For those sources alternate wording must be provided in §63.7545(e)(8). **We suggest the following be provided as an alternate certification in the proposed §63.7545(e)(8)(ii) wording.**

[This facility has expended at least 8 or 24 technical hours, as applicable, towards evaluating steam and process heat production and consumption efficiencies.](#)

Response: We agree but believe that the revision to the wording in item 4 of Table 3 accomplishes the same purpose.

Commenter Name: Jessica Bridges

Commenter Affiliation: United States Clean Heat & Power Association (USCHPA)

Document Control Number: EPA-HQ-OAR-2002-0058-3501-A1

Comment Excerpt Number: 16

Comment: The shorter assessment time period is better, i.e. changing the maximum time from 1 day to 8 technical hours and from 3 days to 24 technical hours.

Response: The EPA acknowledges this comment.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 115

Comment: If EPA imposes an energy assessment, it should include the proposed change to the maximum time of the assessment. In the Reconsidered Boiler MACT Rule, EPA clarified that the time to conduct the energy assessment may be extended "at the discretion of the owner or operator of the affected source." 76 Fed. Reg. 80,651. CIBO supports this approach regarding the timing to conduct energy assessments.

In the Final Boiler MACT Rule, EPA included "stated 'maximum time'" language in the definition of energy assessment, 76 Fed. Reg. 80,615, which could have implied that a deviation or a potential violation would occur if the energy assessment effort exceeded the listed time limits. CIBO supports EPA's new approach because it recognizes that actual times for conducting the assessment can exceed stated maximum times depending on site-specific conditions. A clear statement is critical so that deviations or enforcement is not applicable to the elapsed times expended on energy assessments.

Response: The EPA thanks the commenter for their support.

Commenter Name: Shannon S. Broome

Commenter Affiliation: Auto Industry Forum (AIF)

Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1

Comment Excerpt Number: 49

Comment: The threshold in the "energy assessment" definition appears based on *actual* heat input use as opposed to *potential* heat input use, however, again, the reconsideration proposal is not entirely clear on this point.³³ *See id.* at 80,651. If it is *actual*, what base year should facilities use and may facilities permissibly estimate actual use from centralized NG meters?[Footnote 33: As a corollary, the definition of "energy use assessment" refers to "facilities with affected boilers and process heaters *using*" certain amounts of heat output without clarifying whether "using" refers to actual use or rated capacity. *Id.* at 80,651.]

Response: The definition of "Energy assessment" in 63.7575 has been revised to clarify that the threshold is based on heat input capacity. Heat input capacity is used elsewhere in the rule to determine applicability. Using heat input capacity avoids the issue of identifying an appropriate base year or with estimating actual fuel use.

Commenter Name: Felix Mestey, on behalf of Donald R. Schregardus

Commenter Affiliation: Clean Air Act Services Steering Committee, Department of Defense (DoD)

Document Control Number: EPA-HQ-OAR-2002-0058-3427

Comment Excerpt Number: 3

Comment: The definition of energy assessment in §63.7575 states: "(3) *In the Energy assessment for facilities with affected boilers and process heaters using greater than 1.0 trillion Btu per year, the boiler system and any energy use system accounting for at least 20 percent of the energy output will be evaluated to identify energy savings opportunities.*" Unlike the facilities

with lesser heat usage, this category does not specify the appropriate duration of conducting energy assessments. Leaving the duration of the energy assessment open-ended for this category and the scope of the assessment unclear will likely result in long and expensive energy assessments.

Based on the other two categories used by the EPA, less than 0.3 and 0.3 to 1.0 TBtu/yr, it appears that EPA is using a ratio of one day or 8 technical hours per every 0.3 TBtu/yr. For larger facilities, this ratio is excessive and does not recognize the economy of scale (larger boilers servicing large buildings). DoD recommends a ratio of 8 technical hours per every additional 1.0 TBtu/yr beyond 1.0 TBtu/yr, not to exceed 160 technical hours, although facilities could perform longer duration energy assessments at their discretion. For example, excluding limited-use boilers, the largest USAF facility in terms of TBtu/yr is Tinker Air Force Base (AFB), with approximately 93 boilers having a total capacity of approximately 17.6 TBtu/yr. Using 24 hours for the first TBtu/yr and a ratio of 8 hours per additional 1.0 TBtu/yr, results in a technical hour limit for Tinker AFB's energy assessment of 157 technical hours or about 1.7 hours per boiler, which is sufficient for the purposes of the required energy assessment. However, this ratio could require an unreasonable number of technical hours in certain circumstances; therefore a cap on the number of technical hours should also be included. For example, Arnold AFB has a combined rated heat input capacity of 32.1 TBtu/yr when limited-use boilers are included, and a combined capacity of 14.5 if limited-use boilers are excluded. Using 24 hours for the first TBtu/yr and a ratio of 8 hours per additional 1.0 TBtu/yr results in a technical hour limit for Arnold AFB's energy assessment of 273 technical hours for 41 units including the limited-use units, or about 6.6 hours per boiler. The number of technical hours per boiler for the energy assessment in this case is excessive. This could be prevented by establishing a limit on the maximum number of technical hours for larger facilities.

Revise numbered paragraph (3) in the definition of "energy assessment" in §63.7575 for facilities with units using greater than 1TBtu/yr to specify time duration/size ratio and include a cap to the maximum number of hours that should be used in the energy assessment as follows:

(3) ~~In the e~~Energy assessment for facilities with affected boilers and process heaters using greater than 1.0 trillion Btu per TBtu/year, will be up to 24 technical labor hours in length for the first TBtu/yr plus 8 technical labor hours for every additional 1.0 TBtu/yr not to exceed 160 technical hours, but may be longer at the discretion of the owner or operator. ~~t~~The boiler system(s) and any on-site energy use system(s) accounting for at least 20 percent of the affected unit(s) energy output will be evaluated to identify energy savings opportunities.

Response: We agree with the commenter that leaving the duration of the energy assessment open-ended for this category and the scope of the assessment unclear will likely result in long and expensive energy assessments. The numbered paragraph (3) in the definition of "energy assessment" in §63.7575 has been revised as follows:

(3) Energy assessment for facilities with affected boilers and process heaters with a combined heat input capacity of greater than 1.0 trillion Btu/year will be up to 24 on-site technical labor hours in length for the first TBtu/yr plus 8 on-site technical labor hours for every additional 1.0 TBtu/yr not to exceed 160 on-site technical hours, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s), process heater(s), and any on-site energy use system(s) accounting for at least 20 percent of the affected unit(s) energy (e.g., steam,

process heat, hot water, or electricity) production or consumption, as applicable, will be evaluated to identify energy savings opportunities.

Commenter Name: Jessica Bridges

Commenter Affiliation: United States Clean Heat & Power Association (USCHPA)

Document Control Number: EPA-HQ-OAR-2002-0058-3501-A1

Comment Excerpt Number: 25

Comment: 40 CFR 63.7575, Revise the definition of “energy assessment” to clarify the length of days for each category of facilities. We are supportive of the shortening to 8 technical hours and 24 technical hours.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3427, excerpt 3.

Commenter Name: Felix Mestey, on behalf of Donald R. Schregardus

Commenter Affiliation: Clean Air Act Services Steering Committee, Department of Defense (DoD)

Document Control Number: EPA-HQ-OAR-2002-0058-3427

Comment Excerpt Number: 7

Comment: Revise numbered paragraph (3) in the definition of "energy assessment" in §63.7575 for facilities with units using greater than 1TBtu/yr to specify time duration/size ratio and include a cap to the maximum number of hours that should be used in the energy assessment as follows:

(3) ~~In the e~~Energy assessment for facilities with affected boilers and process heaters using greater than 1.0 ~~trillion Btu per TBtu~~/year, will be up to 24 technical labor hours in length for the first TBtu/yr plus 8 technical labor hours for every additional 1.0 TBtu/yr not to exceed 160 technical hours, but may be longer at the discretion of the owner or operator. ~~t~~The boiler system(s) and any on-site energy use system(s) accounting for at least 20 percent of the affected unit(s) energy output will be evaluated to identify energy savings opportunities.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3427, excerpt 3.

Commenter Name: Bill Wilson

Commenter Affiliation: Washington State University

Document Control Number: EPA-HQ-OAR-2002-0058-3786-A1

Comment Excerpt Number: 1

Comment: My greatest concern about energy assessment language in the Final Rule Reconsideration is the approach specifying the duration of an energy assessment by prescribing a maximum time expenditure ("technical labor hours") based on affected boilers and process heaters annual energy consumption threshold brackets. As a definition of "technical labor hours" has not been provided, my assumption is this terms means the total time expenditure by an energy assessor to perform an energy assessment from pre-assessment contact and information gathering through the "on-site" systems observation period at the facility and subsequent post-assessment analyses and generation of a final report.

Response: The definition of "Energy assessment" has been revised to clarify that the technical hours are "on-site" technical hours to conduct the evaluations. The on-site technical hours do not cover the pre-assessment contact and information gathering and the subsequent post-assessment analysis and generation of a final report.

Commenter Name: Jennifer Youngblood
Commenter Affiliation: National Tribal Air Association
Document Control Number: EPA-HQ-OAR-2002-0058-3667-A2
Comment Excerpt Number: 5

Comment: Proposed §63.7530(e) must also be revised to reflect the hour limits and to clarify that the facility is only certifying to the accuracy of the information used in the assessment as a snapshot. Since the assessment is a onetime requirement, the certification should indicate that it is only an accurate depiction of the facility at the time of the assessment, thereby removing any suggestion that a new assessment is needed if the facility changes. We recommend the following revisions to the proposed §63.7530(e).

You must include with the Notification of Compliance Status a signed certification that the energy assessment was completed according to Table 3 to this subpart or the hour limits specified in the energy assessment definition was reached and is an accurate depiction of your facility at the time of the assessment.

Response: We agree with the second edit and have revise §63.7530(e) to read "You must include with the Notification of Compliance Status a signed certification that the energy assessment was completed according to Table 3 to this subpart and is an accurate depiction of your facility at the time of the assessment. The first suggested edit has been addressed by the revision to Item 4 of Table 3.

Commenter Name: Dakota Gasification Company Great Plains Synfuels Plant
Commenter Affiliation: David W. Peightal
Document Control Number: EPA-HQ-OAR-2002-0058-3424
Comment Excerpt Number: 7

Comment: DGC agrees with EPA to allow energy assessments performed after January 1, 2008, or within the window of the initial proposal to be acceptable for meeting the requirement. DGC was fortunate to have had an independent energy assessment performed by the U.S. DOE in 2009. DGC has implemented some of those recommendations and hopes to use the 2009 DOE energy assessment to demonstrate compliance with the work practice standard.

Response: The EPA thanks the commenter for their support.

Commenter Name: Michael Bradley
Commenter Affiliation: The Clean Energy Group
Document Control Number: EPA-HQ-OAR-2002-0058-3495-A1
Comment Excerpt Number: 3

Comment: Establishing maximum duration as a metric for the appropriate depth of an assessment is reasonable, with the proposed revisions to ensure that exceeding the recommendation, or spreading an appropriate-length assessment over several days, is not a violation of the rule.

Response: The EPA thanks the commenter for their support.

5Z. Out of Scope: Energy Assessment

Commenter Name: Dakota Gasification Company Great Plains Synfuels Plant

Commenter Affiliation: David W. Peightal

Document Control Number: EPA-HQ-OAR-2002-0058-3424

Comment Excerpt Number: 8

Comment: EPA should allow facilities to conduct their own self assessments instead of hiring certified professionals. DGC has processes that would require third-party auditors to spend a great amount of time learning intricacies of the facility, possibly including information that is considered CBI, which could put DGC's competitive advantage at risk. DGC considers the energy assessment as a good business practice and is confident that the skills and knowledge of the in-house personnel would meet the qualified assessor and be sufficient to perform an energy assessment comprehensively and accurately.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Michael Livermore, Jason Schwartz

Commenter Affiliation: Institute for Policy Integrity, NYU School of Law

Document Control Number: EPA-HQ-OAR-2002-0058-3432-A1

Comment Excerpt Number: 9

Comment: The requirement of an energy assessment should provide net benefits to regulated entities as a whole, as well as substantial environmental and health benefits to the entire country. But in order to ensure that maximum net benefits are reaped, EPA should go further and require implementation of all "cost-effective energy conservation measures." Mandatory implementation is justified regardless of whether EPA continues to use its flawed definition of "cost-effective," or adopts the more economically rational definition discussed above.

First, it should be noted that the statutory touchstone for whether EPA should issue this requirement is whether it is "achievable" under Section 112(d). For a range of definitions of "cost-effective," EPA can determine that requiring implementation of "cost-effective energy conservation measures" is, in fact, both achievable and economically feasible.²⁵

As explained above, EPA has defined "cost-effective" to reflect only private costs and benefits. This makes the case for requiring implementation very simple. Given a suitable discount rate and time period for the analysis (discussed above), there will be zero net costs to regulated entities from implementing cost-effective measures. Since there will be zero net costs, the requirement should not pose any burden on regulated entities.

Of course, standard economic theory would suggest that regulated entities (as rational actors) would implement all energy conservation measures that have net private benefits on their own, without any requirement. But as discussed above, firms often fail to take advantage of all opportunities to decrease costs (or increase profits). If EPA issues this requirement, it can be assured that the regulated entities will not let this opportunity pass them by. EPA should take the step to ensure that regulated entities will not blindly comply with the bare minimum of the regulation by filing an energy assessment and then promptly forgetting about it.

[Footnote 25 Under CAA §112(h), EPA may exempt sources from requirements under Section 112(d) if the requirement is not feasible. However, given a proper definition of "cost-effective," this should not be an issue.]

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: John V. Corra, Director

Commenter Affiliation: State of Wyoming Department of Environmental Quality

Document Control Number: EPA-HQ-OAR-2002-0058-3435-A1

Comment Excerpt Number: 3

Comment: The State of Wyoming would appreciate clarification in the rule regarding EPA's expectations for implementing the results of the energy assessment. By definition, an energy assessment is a review of the boiler system and energy use system accounting for specified percentages of the energy output to identify energy savings opportunities, within the time limit of performing energy assessment. It is anticipated that the results of the energy assessment will vary significantly in cost, and without guidance from EPA on implementing the results of the energy assessment, implementation will be fragmented.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Paul G. Page

Commenter Affiliation: AK Steel Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3457-A2

Comment Excerpt Number: 13

Comment: More importantly however, AK Steel fails to understand how EPA believes that it can "certify" third-party assessors to visit our facilities for a short period of time, probably without prior knowledge of our industry much less our facility's operations, and perform a "thorough" energy assessment.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Paul G. Page

Commenter Affiliation: AK Steel Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3457-A2

Comment Excerpt Number: 14

Comment: As EPA well knows, the iron and steel industry is highly energy intensive. In a global market, steel companies must reduce costs wherever possible to stay competitive and energy costs are a key component of those reductions. Accordingly, AK Steel is continually performing energy assessments to ascertain what programs, practices, or installations can be implemented in a cost-effective manner to reduce energy costs. We conduct these assessments by utilizing personnel and contractors with years of experience and expertise within our industry and at our facilities. As a result, we fail to see what additional benefit or to what purpose an additional energy assessment performed by a third-party assessor will achieve or how the costs can be justified.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Lee Zeugin and Lauren Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1

Comment Excerpt Number: 11

Comment: If EPA keeps the energy assessment requirement in the rule, it should exclude electric utility auxiliary boilers from that requirement. As noted above, auxiliary boilers typically operate only during the startup of an EGU. In some cases, auxiliary boilers may be used to supply building heat but only when the main generating unit is offline. The annual capacity factor of auxiliary boilers is very low. Consequently, an energy assessment of an entire electric utility generating facility would not have any impact on the operation or fuel usage of an auxiliary boiler. Because the energy assessment requirement would serve no useful purpose for an electric generating facility, auxiliary boilers should be exempted from this requirement.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Jessica Bridges

Commenter Affiliation: United States Clean Heat & Power Association (USCHPA)

Document Control Number: EPA-HQ-OAR-2002-0058-3501-A1

Comment Excerpt Number: 14

Comment: The existing CHP fleet (82 GW) already avoids more than 1.8 Quadrillion British thermal units (Quads) of fuel consumption and 241 million metric tons of carbon dioxide (CO₂) emissions annually compared to traditional separate production of electricity and thermal energy. This CO₂ reduction is the equivalent of removing more than 45 million cars from the road. The potential additional CHP of 130-170 GW could double these benefits for the additional installations in terms of fuel consumption and CO₂ reduction.

Fortunately these benefits can be readily calculated for CHP projects at relatively low cost during the Energy Assessment Phase. We realize that cost of the Energy Assessments is an

important factor in EPA's analyses. However, a ready tool developed by EPA already exists. It is the CHP Emissions Evaluator available from EPA's CHP Partnership.⁷

For perspective in examining the EPA position here, we looked at TABLE 5—SUMMARY OF CAPITAL AND ANNUAL COSTS FOR NEW AND EXISTING SOURCES⁸ and took the cost estimate numbers for Energy Assessments Annualized Costs (considering fuel savings) that totaled \$28 million and divided it by the number of affected sites (1704). The result is an annualized \$16,432 per Energy Assessment. Using a tool such as the CHP Emission Evaluator, even if it requires some modification for the purpose, should not significantly raise the average energy assessment costs.

[Footnote]

(7) <http://www.epa.gov/chp/basic/calculator.html>

(8) 76 FR 80622

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Robert R. Perry

Commenter Affiliation: FirstEnergy Generation Corp (FGCO)

Document Control Number: EPA-HQ-OAR-2002-0058-3518-A1

Comment Excerpt Number: 4

Comment: EPA has stated that the Energy Assessment is a Beyond the Floor requirement. EPA has provided no basis that any additional Beyond the Floor requirements are even needed. EPA has failed to define any risks that remain after the MACT Floor Analysis requirements have been implemented. Additionally, FGCO contends that EPA has over extended its authority by requiring the energy assessment of a significant portion of the total facility rather than limiting it to the subpart DDDDD unit.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 118

Comment: EPA proposed a beyond the floor requirement of an energy assessment in the June 4, 2010 proposed Boiler MACT. We have already provided extensive comments on the proposed energy assessment. The energy assessment requirement remained in the March 21, 2011 final rule and the December 23, 2011 re-proposed rule with some changes. As indicated in our reconsideration petition, we support:

- The removal of the mandatory use of the ENERGY STAR program as a requirement. 76 Fed. Reg. 15618.

- Exempting facilities and companies that have already conducted detailed energy assessments should from the requirement of conducting an energy assessment if one has been conducted within 3 years prior to promulgation. 76 Fed. Reg. 15632. • Removing the certified assessor requirement.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 119

Comment: We continue to believe, as stated in our comments on the June 4, 2010 proposal, that EPA is not justified in extending the scope of the assessment beyond the affected source. The "affected source" regulated by this NESHAP is the specified emission unit – boilers and process heaters – not the major source location of the emission unit. The energy assessment requires investigation into equipment not covered by the Boiler MACT or any other Section 112 standard.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 116

Comment: If EPA imposes an energy assessment, it should not be submitted to EPA and additional CBI protections are needed. In the Reconsidered Rule, EPA proposes to remove the requirement that sources submit their energy assessments upon a request from EPA. 76 Fed. Reg. 80,641; 40 C.F.R. § 63.7530(e). EPA notes that it recognizes the sensitivity of confidential business information (CBI) contained in energy assessments. EPA's Response to Public Comments on EPA's National Emission Standards for Hazardous Air Pollutants for Major Source Industrial Commercial Institutional Boilers and Process Heaters - Volume 1 of 2 (Response to Comment Excerpt Number 215). CIBO supports protecting CBI to the fullest extent allowed. As CIBO stated in its Petition for Reconsideration of the Final Area Source Rule, EPA should provide the same level of CBI protection for area sources as it does for major sources. Submission of energy assessments is not required under the Final Boiler MACT Rule. CBI is equally an issue for companies operating area source boilers as it is for major source boilers and process heaters. As such, a similar approach in both rules is justified.

Here, EPA is exercising its authority under §112. *See, e.g.*, 76 Fed. Reg. 80,625. As EPA acknowledges, §112 directs the agency "to develop NESHAP which require existing and new major sources to control emissions of HAP using MACT based standards." *Id.* An energy assessment is not an emission standard; therefore, if EPA would like to collect this information for policy purposes or to inform other rulemaking efforts, it must comply with the procedural requirements to issue a §114 request.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 117

Comment: EPA must comply with the PRA, which requires that the agency receive approval from OMB before issuing similar §114 requests to ten (10) or more respondents collecting substantially similar information in any 12-month period. 5 C.F.R § 1340.3(c). The OMB's approval is in the form of an Information Collection Request ("ICR"), which must go through public notice and comment. Courts have determined that compliance with an information request is not required where "the demand for information or documents is arbitrary and capricious, an abuse of discretion, or otherwise not in accordance with law." *U.S. v. Pretty Prod., Inc.*, 780 F. Supp. 1488, 1506 n.23 (S.D. Ohio 1991).

The regulatory text of the Reconsidered Boiler MACT Rule indicates that sources must demonstrate compliance with the energy assessment requirement by including in their Compliance Status Report a certification that the facility has completed an energy assessment consistent with the regulatory requirements:

(e) You must include with the Notification of Compliance Status a signed certification that the energy assessment was completed according to Table 3 to this subpart and is an accurate depiction of your facility.

Section 63.7530(d), 76 Fed. Reg. 80,641.

However, the Preamble of the Reconsidered Boiler MACT Rule appears to indicate that in addition to the foregoing certification, sources must also submit documentation of cost effective energy conservation measures:

Further, all owners or operators of major source facilities having boilers and process heaters subject to this final rule are required to submit to the delegated authority or the EPA, as appropriate, documentation that an energy assessment was performed by a qualified energy assessor and documentation of the cost-effective energy conservation measures identified by the energy assessment.

76 Fed. Reg. 80,603.

As CIBO asserted in its comments on the Proposed Rule, much of the analysis of cost-effective efficiency measures will be CBI, and sources should not be required to submit that information to EPA. EPA's regulations provide that information must be protected from disclosure to protect trade secrets and a business' right to limit the use or disclosure of information "by others in order that the business may obtain or retain business advantages it derives from its rights in the information." 40 C.F.R. § 2.201(e). Commercial or financial information involuntarily submitted by a company to EPA is entitled to confidentiality if "disclosure of the information is likely to . . . cause substantial harm to the competitive position of the person from whom the information

was obtained." *Nat'l Parks & Conservation Ass'n v. Morton*, 498 F.2d 765, 770 (D.C. Cir. 1974); *Critical Mass Energy Project v. Nuclear Regulatory Comm'n*, 975 F.2d 871, 879 (D.C. Cir. 1992) (reaffirming the *National Parks* test for determining whether information submitted under compulsion is confidential); *see also* 40 C.F.R. § 2.208(e)(1). Parties claiming confidentiality need only show "competition and a likelihood of substantial competitive injury." *CNA Fin. Corp. v. Donovan*, 830 F.2d 1132, 1152 (D.C. Cir. 1987).

EPA's regulations provide that emissions data cannot be protected from disclosure as CBI. 40 C.F.R. § 2.301(e). "Emission data" is "any source of emission of any substance into the air" that is "necessary to determine the identity, amount, frequency. . . of any emission. . . emitted by the source." 40 C.F.R. § 2.301(a)(2)(i); *see also RSR Corp. v. EPA*, 588 F. Supp. 1251, 1255 (N.D. Tex. 1984).

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 118

Comment: The information collected to comply with the energy assessment requirement is not "emissions data." 40 C.F.R. § 2.301(e). It is not "necessary" to determine emissions emitted by a source. *Id.* Rather, the energy assessment includes:

- An evaluation of operating characteristics of the facility, specifications of energy using systems, operating and maintenance procedures, and unusual operating constraints;
- An inventory of major energy consuming systems;
- A review of available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage;
- A review of the facility's energy management practices and recommendations for improvements;
- A list of major energy conservation measures and their energy savings potential;
- A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments.

The foregoing information is commercially valuable because its release would potentially provide competitors with a window into the reporter's current operations, operating costs, and expansion plans. For EPA to require the public disclosure of information of this nature (including engineering plans or the costs of energy savings projects), ignores the competitiveness implications of such disclosure. A company that develops a method to significantly reduce its energy costs – whether through improved maintenance practices or new projects - will not want its competitors to be aware of such proprietary information. Similarly, that company would not want to make its competitors aware of any operating constraints that might highlight weaknesses within a facility. If energy assessments are made publically available, competitors that took a

minimalist approach in conducting their own energy assessments could benefit from the disclosures of others without incurring the time and expense to independently develop those plans. *See Webb v. Dep't of Health & Human Serv.*, 696 F.2d 101, 103 (D.C. Cir. 1982). As a result, reporters that prepare more comprehensive and detailed energy assessments would suffer irreparable harm. EPA is not authorized under the CAA or its implementing regulations to cause companies such injuries by mandating the disclosure of proprietary information. 42 U.S.C. § 7414(c); 40 C.F.R. § 2.301(b)(i).

The lapse of time would not diminish the sensitivity of disclosing this information. There is no time after which this information could be released that would avoid these potential competitive harms. Given these concerns, it would not be appropriate to impose a time limit on the confidentiality of the energy assessment information.

CIBO objects to requiring sources to submit their energy assessments even if they are afforded CBI status because those protections are not necessarily complete or permanent. Such protections are insufficient because EPA CBI determinations are subject to reevaluation. 40 C.F.R. § 2.205(h). EPA has the discretion to modify prior CBI determinations and conclude that CBI is no longer entitled to confidential treatment because of a change in applicable law or newly discovered or changed facts. *Id.*

For the foregoing reasons, EPA should amend the Preamble to remove this statement about submitting such documentation so that the Preamble is consistent with the rule text, which only requires entities to submit a certification that the energy assessment was conducted.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Bruce A. Steiner

Commenter Affiliation: American Coke and Coal Chemical Institute (ACCCI)

Document Control Number: EPA-HQ-OAR-2002-0058-3547-A2

Comment Excerpt Number: 15

Comment: But more fundamentally, this undertaking is a means to no particular end. Any potential emission reductions, energy reductions, or non-air quality health and environmental benefits are not estimable because the proposed energy assessment requirement is just a study. While the Reconsidered Rule speculates that facilities may elect to implement certain findings, it cannot quantify any emissions reductions that may occur with the requisite level of certainty. Thus, this requirement fails EPA's traditional cost-effectiveness evaluation, which focuses on the annual cost per ton of HAP emissions eliminated. *See, e.g., Artega Specialties S.A.R.L. v. EPA*, 323 F.3d 1088, 1089-90 (D.C. Cir. 2003). EPA apparently has not performed this calculation and it is impossible for any impacted entity to do so. While the Reconsidered Rule offers a rough emissions reduction estimate, that estimate apparently stems from presumed voluntary measures, with no solid indication that any HAP reduction will actually occur. Since there are no demonstrable emissions reductions from the proposed energy assessment requirement, the significant costs associated with that process are not warranted. As such, this proposed beyond-the-floor control fails the threshold test imposed by §112(d)(2).

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Bruce A. Steiner

Commenter Affiliation: American Coke and Coal Chemical Institute (ACCCI)

Document Control Number: EPA-HQ-OAR-2002-0058-3547-A2

Comment Excerpt Number: 16

Comment: Even if viable, the proposed energy assessment requirement presents serious implementation difficulties. One threshold problem is that the proposed energy assessment must be performed by “qualified personnel.” These inspectors may well have a conflict of interest - particularly where their firms would stand to benefit from implementing any suggested modifications. As a result, regulated entities would have a difficult time delineating between truly appropriate modifications and those suggested by the evaluator in hopes of gaining additional business.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Bruce A. Steiner

Commenter Affiliation: American Coke and Coal Chemical Institute (ACCCI)

Document Control Number: EPA-HQ-OAR-2002-0058-3547-A2

Comment Excerpt Number: 17

Comment: the number of personnel qualified to perform energy assessments is unknown. The Reconsidered Rule would require assessors to complete the Department of Energy’s Qualified Specialist Program or become a Certified Energy Manager by the Association of Energy Engineers. Given the huge number of facilities impacted by the Reconsidered Rule and related Area Source standards,²⁸ there may well be a shortage of qualified personnel. That raises serious concerns, including: (1) personnel with significant experience and true expertise will be unavailable, (2) compliance may become difficult or impossible in a timely manner, and (3) competition for the limited pool of highly qualified assessors will cause their rates to increase significantly. There would also be substantial inefficiency associated with getting a third-party inspector sufficiently “up to speed” to make informed conclusions regarding industries’ highly complex steelmaking operations. In contrast, existing operations personnel already have extensive manufacturing expertise and unique knowledge of the particular processes at each of our industries’ facilities. As such, they are better situated to make informed, realistic determinations of where energy reductions may be achievable than outside assessors - and at far lower cost. Indeed, they have already been doing so effectively for years at most of our industries’ major facilities.

[Footnote]

(28) For major sources, 1,608 facilities would be required to conduct energy audits. Methodology for Estimating Cost and Emissions Impacts for Industrial, Commercial, Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air

Pollutants - Major Source, from S. McClutchey, A. Singleton & G. Gibson, to J. Eddinger, at §3.4 (Apr. 2010), Docket ID No. OAR-2002-0058-0812. Up to 94,339 area source facilities may also be required to conduct energy audits. Methodology for Estimating Impacts from Industrial, Commercial, Institutional Boilers at Area Sources of Hazardous Air Pollutant Emissions, from G. Gibson, S. McClutchey & A. Singleton, to J. Eddinger, at §3.2 (Apr. 2010), Docket ID No. OAR-2006-0790-0032.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Bruce A. Steiner

Commenter Affiliation: American Coke and Coal Chemical Institute (ACCCI)

Document Control Number: EPA-HQ-OAR-2002-0058-3547-A2

Comment Excerpt Number: 18

Comment: We are concerned that the proposed requirement to conduct a facilitywide energy assessment will be duplicative and unnecessary. As recognized in the Reconsidered Rule, fuel and energy costs are major drivers at many facilities.²⁹ That is particularly true for companies such as coke production facilities that require large amounts of fuel and energy to operate. Given those existing business incentives, ACCCI members have already invested heavily to assess cost-effective energy efficiency opportunities. Further, we have made (and continue to make) significant voluntary investments implementing key efficiency projects - including under the EnergyStar program. For EPA to require facilities that have already completed these steps to repeat the effort offers little practical benefit.

[Footnote]

(29) Sector-Based Pollution Prevention: Toxic Reductions through Energy Efficiency and Conservation Among Industrial Boilers, The Delta Institute, at §3.2, Docket ID No. OAR-2002-0058-0842 (July 2002) (concluding that Fuel is traditionally the “most costly item associated with boiler operation”).

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: John M. Cullen

Commenter Affiliation: Masco Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3661-A2

Comment Excerpt Number: 13

Comment: Masco previously commented that "EPA should allow existing energy management plans and assessments at affected companies to act as a substitute for the energy assessment requirements proposed." Masco notes that the Agency has revised the rule to permit use of an existing energy management plan "completed on or after January 1, 2008, that meets or is amended to meet the energy assessment requirements" in the rule. This change represents an improvement to the rules.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Pat Dennis

Commenter Affiliation: Archer Daniels Midland Company

Document Control Number: EPA-HQ-OAR-2002-0058-3670-A2

Comment Excerpt Number: 13

Comment: ADM objects to requiring sources to submit their energy assessments even if they are afforded CBI status because those protections are not necessarily complete or permanent. Such protections are insufficient because EPA CBI determinations are subject to reevaluation. EPA has the discretion to modify prior CBI determinations and conclude that CBI is no longer entitled to confidential treatment because of a change in applicable law or newly discovered or changed facts.

For the foregoing reasons, EPA should amend the Preamble to remove this statement about submitting such documentation so that the Preamble is consistent with the rule text, which only requires entities to submit a certification that the energy assessment was conducted.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: David Gardiner

Commenter Affiliation: The Alliance for Industrial Efficiency

Document Control Number: EPA-HQ-OAR-2002-0058-3683-A2

Comment Excerpt Number: 1

Comment: We commend EPA for including provisions that support energy efficiency in the Rule. As EPA noted in the Response to Comments on the March Rule, "One of the opportunities for pollution prevention lies in simply using energy efficient technologies to minimize the generation of emissions."¹ Indeed, energy-efficient technologies can reduce fuel use and associated emissions not only of the hazardous air pollutants at the heart of the Boiler MACT, but of conventional pollutants as well.

Notably, the Boiler MACT includes a number of provisions that enable regulated entities to cost-effectively reduce emissions through energy efficiency. These include work-practice standards, energy which would also enhance electricity reliability in states that are concerned about that. We commend EPA for drafting a rule that encourages industrial boiler owners to consider CHP and WHR as part of a commonsense compliance option. The December Rule will lower emissions, save American manufacturers money on their energy bills, enhance their competitiveness, and increase electric reliability in industrial states.

[Footnote 2: Estimate assumes CHP installations for 478 major source, non-CHP, non-limited use boilers equal to or greater than 10 MMBTU/hr from EPA's "Emissions Database for Boilers and Process Heaters Containing Stack Test, CEM, & Fuel Analysis Data Reported Under ICR No. 2286.01 and ICR No. 2286.03 (Version 6).mdb", Feb, 2011. Estimate also includes an additional 61 non limited-use, coal-fired boilers with heat-input rates greater than or equal to 10

MMBTU/hr from EPA's updated "Appendix B-1 Emission Reduction Detail for Existing Units," December 2011. (both data sets available online at <http://www.epa.gov/ttn/atw/boiler/boilerpg.html>). Thus estimate based on capacity for 539 major source boilers.]

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Tangelia Niemann

Commenter Affiliation: Texas Commission on Environmental Quality (TCEQ)

Document Control Number: EPA-HQ-OAR-2002-0058-3594-A3

Comment Excerpt Number: 6

Comment: The TCEQ opposes any revision to the rule that would require the implementation of the energy assessment recommendations. Only the companies operating the facilities are qualified to determine those energy efficiency improvement measures that are appropriate and cost-effective for implementation at the site. Attempting to enforce which recommendations a company should have implemented as being cost-effective energy efficiency measures would be difficult and entail the TCEQ performing a separate independent evaluation of the measures. Neither the TCEQ nor the EPA should arbitrarily accept an energy assessor's recommendations as an enforceable requirement under the rule. Additionally, a requirement to implement the results of the energy assessment might bias companies providing energy assessment services, particularly if the assessment companies also provide the services or products necessary for the energy improvements. The EPA has already expressed concern of outside energy assessors attempting to expand the scope and effort required for an energy assessment beyond what would be necessary for a facility. This concern was the EPA's rationale for establishing the maximum time limits for the energy assessment so that companies would have a means to limit the time and effort of an outside energy assessor contracted to perform the assessment (76 FR 80615). Attempting to mandate companies implement the recommendations of the energy assessors would only further encourage such actions.

The TCEQ strongly recommends that the EPA remove the energy assessment requirement from 40 CFR 63 Subpart DDDDD. While energy efficiency evaluations should be encouraged, such evaluations should remain voluntary through programs such as the EPA's Energy Star Program and not mandated through regulation.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

104A. Remove Energy Assessment [DENIED PETITIONER ISSUE]

Commenter Name: Paul G. Page

Commenter Affiliation: AK Steel Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3457-A2

Comment Excerpt Number: 12

Comment: AK Steel supports ACCCI's comments regarding the Energy Assessment requirement including questioning EPA's authority to require it as part of this NESHAP regulation, what it has to do with the establishment of HAP emissions associated with boiler operations, and how this information will lead to the promulgation of HAP emission standards.

Response: The EPA denies this petition for reconsideration issue and the comment is out-of-scope of the reconsideration proposal. The authority to require an energy assessment was subject to notice and comment. Rationale and responses to comments are provided at 75 FR 32041 and 76 FR 15633.

This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Paul G. Page

Commenter Affiliation: AK Steel Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3457-A2

Comment Excerpt Number: 16

Comment: For multiple reasons, AK Steel encourages EPA to remove the requirement to perform the Energy Assessment. EPA has given no indication as to how this requirement is relevant to the NESHAP Standard, what they intend to do with the information, how the information will be relevant and comparative to other facility assessments based on a multitude of assessors performing them, and what EPA will expect companies to do as a result of these assessments. As a result, the Energy Assessment would appear to serve no beneficial purpose and, therefore, needs to be removed as a requirement from the final rule.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3457-A2, excerpt 12.

This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Eric Guelker, Alliant Energy Corporate Services, Inc.

Commenter Affiliation: Interstate Power and Light Company (IPL) and Wisconsin Power and Light Company (WPL), Alliant Energy Corp.

Document Control Number: EPA-HQ-OAR-2002-0058-3492-A1

Comment Excerpt Number: 12

Comment: Alliant Energy does not believe EPA has substantiated that "beyond the floor" controls of an energy assessment are warranted. EPA can impose "beyond the floor" requirements that are more stringent than the MACT floor, but must take cost, energy, and other environmental impacts into consideration when doing so. EPA's rule impact analysis has not fully vetted the costs of conducting an energy assessment and Alliant Energy believes that further inquiry would find that these costs estimates are significantly understated. Moreover, EPA has not explained how adding this as a more stringent requirement results in any documentable reduction of environmental impacts and associated risks.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3457-A2, excerpt 12.

This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Eric Guelker, Alliant Energy Corporate Services, Inc.

Commenter Affiliation: Interstate Power and Light Company (IPL) and Wisconsin Power and Light Company (WPL), Alliant Energy Corp.

Document Control Number: EPA-HQ-OAR-2002-0058-3492-A1

Comment Excerpt Number: 13

Comment: Existing facilities already have sufficient incentive to run their combustion units as efficiently as possible by realizing reduced fuel consumption and lower operating costs. Therefore, the energy assessment achieves nothing more than being an unwarranted administrative cost burden to companies.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3457-A2, excerpt 12.

This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Kevin G. Desharnais, Attorney, Mayer Brown LLP

Commenter Affiliation: United States Sugar Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3496-A1

Comment Excerpt Number: 3

Comment: In its Reconsideration Proposal, EPA retains the requirement that sources perform a mandatory energy assessment as a "beyond-the-floor" requirement. While the Reconsideration Proposal clarifies the scope of the energy assessment as limited to onsite energy use systems, it does not address the appropriateness of the energy assessment in the first instance, and fails to respond to the legitimate criticisms articulated in US Sugar's comments to the Proposed Rule.

EPA apparently continues to rely upon the arguments articulated in the Preamble to the Final Rule, supporting its mandatory energy assessment requirement with reference to CAA section 112(d)(2). See 76 Fed. Reg. at 15633. However, Section 112(d)(2) provides no authority for a work practice standard like an energy assessment, authorizing only an emissions standard, not a work practice standard. See 42 U.S.C. § 7412(d)(2) ("Emissions standards promulgated under this subsection ... "); The authority for a work practice standard comes from Section 112(h). But that section specifically states that a work practice standard may only be used when an emission standard is not feasible. See 42 U.S.C. § 7412(h)(1) ("For purposes of this section, if it is not feasible in the judgment of the Administrator to prescribe or enforce an emission standard for control of a hazardous air pollutant or pollutants, the Administrator may, in lieu thereof, promulgate a design, equipment, work practice, or operational standard, or combination thereof, which in the Administrator's judgment is consistent with the provisions of subsection (d) or (f) of this section").

As U.S. Sugar explained in its comments to the proposed rule, EPA has determined that an emission standard is feasible here, and has in fact proposed such a standard for all boilers above certain volume thresholds. Accordingly, not only is a work practice standard not needed, there is

no legal basis for EPA to require it. EPA may not require both a work practice standard and an emission limit, as the two provisions are mutually exclusive under the statute. See *Sierra Club v. EPA*, 479 F.3d 875, 884 (D.C. Cir. 2007) (striking down work practice standard because section 74 1 2 (h) "allows EPA to substitute work practice standards for emission floors only if measuring emission levels is technologically or economically impracticable").

Response: See the response to comment EPA-HQ-OAR-2002-0058-3457-A2, excerpt 12.

This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Lee Zeugin and Lauren Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1

Comment Excerpt Number: 10

Comment: The scope of the energy assessment in the 2011 final rule goes beyond IB units to focus on the "major source facility" and the "major systems consuming energy" at the facility. EPA justifies the energy assessment requirement as a way "to identify energy conservation measures (such as process changes or other modifications to the facility) that can be implemented to reduce the facility energy demand for the affected boiler, which would reduce its fuel use."⁸ The problem with EPA's stated justification is that it fails to fully consider the ramifications of the energy assessment requirement on the entire universe of facilities subject to the rule. As a result, while EPA attempts to tie the energy assessment to the regulation of the IB unit at a given facility, the scope of the requirement is overly broad and can affect the operation of other parts of the facility and, as a result, exceeds EPA's legal authority.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3457-A2, excerpt 12.

This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: David A. Buff, Golder Associates Inc.

Commenter Affiliation: Florida Sugar Industry (FSI)

Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1

Comment Excerpt Number: 44

Comment: FSI objects to the energy assessment as a "beyond-the-floor" requirement for all major sources of HAPs. The FSI already has provided EPA with extensive comments and objections concerning the proposed energy assessment,³ and the FSI adopts those same objections to the requirements in the Proposed Boiler MACT Rule. As indicated in the FSI's previous comments:

- At a minimum, EPA is over-reaching when it attempts to require energy assessments as part of EPA's efforts to set emission standards under Section 112 of the Clean Air Act ("CAA").

- At a minimum, EPA is over-reaching when it attempts to extend the proposed energy assessment to include equipment that is not located within the traditional boundaries of a "boiler system."
- At a minimum, EPA is overreaching when it attempts to extend its authority over boilers by expanding the definition of a "boiler system" to include unrelated "energy consuming systems".

The FSI continues to believe that EPA is not justified in extending the scope of the energy assessment beyond the affected source. The "affected source" regulated by this NESHAP consists of boilers and process heaters – not the other equipment and "energy consuming systems" that are co-located with the affected source. The energy assessment requirements in the Proposed Boiler MACT Rule will mandate investigations into equipment and systems that are not properly within the scope of this Section 112 rulemaking process.

[Footnote]

(3) See comments from Golder Associates Inc. dated August 23, 2010, submitted on behalf of the FSI, submitted to docket EPA-HQ-OAR-2002-0058.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3457-A2, excerpt 12.

This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 82

Comment: EPA has authority to regulate HAP emissions from major sources under section 112(d) of the Clean Air Act. This attempt to further regulate the way major sources consume energy under this rule is beyond EPAs authority. EPA should eliminate its definitions of "boiler system" and "energy use system." EPA should further limit the scope of energy assessments to "boiler(s)" and "process heater(s)" as currently defined.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3457-A2, excerpt 12.

This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Shannon S. Broome

Commenter Affiliation: Auto Industry Forum (AIF)

Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1

Comment Excerpt Number: 45

Comment: EPA does not propose to eliminate the energy assessment nor does it propose to limit the assessment to the boiler and/or process heater only. In fact, EPA proposes no changes to

the components of the assessment on which AIF commented. Instead, EPA merely clarifies that it did not intend in the final rule for the assessment to include energy use systems using electricity purchased from an offsite source or energy use systems located offsite, indicating by the energy assessment still includes energy use systems on-site, *i.e.*, the assessment still extends beyond the boiler and/or process heater itself. Specifically, EPA proposes to amend the prior language of the third component of the energy assessment enumerated in Table 3 from “[a]n inventory of the major energy consuming systems” to:

An inventory of major systems consuming energy from affected boilers and process heaters and which are under the control of the boiler/process heater owner/operator.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3457-A2, excerpt 12.

This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Ahmed Idriss, Capital Power Corporation

Commenter Affiliation: CPI USA North Carolina (CPI NC)

Document Control Number: EPA-HQ-OAR-2002-0058-3524-A1

Comment Excerpt Number: 7

Comment: CPI NC does not support EPA’s use of energy assessments in the Proposed Rule. CPI NC does not believe that such a requirement is contemplated within the text of the Clean Air Act. Nor is it reasonable to believe that such a requirement would help to achieve the purpose of the Proposed Rule.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3457-A2, excerpt 12.

This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 109

Comment: In the 2011 Final Boiler MACT Rule, EPA grounded its authority to require sources to conduct an energy assessment in CAA §112: "the energy assessment will generate emission reductions through the reduction in fuel use beyond those required by the floor" and that "the requirement to perform the energy audit is, of course, a requirement that can be enforced and thus a standard." 76 Fed. Reg. 15,632-33.

CIBO challenged that basis of authority in prior comments on these rules and reasserts those positions here. In short, an energy assessment does not purport to limit emissions, nor impose more stringent standards than the MACT floor and is, therefore, not a beyond-the-floor standard consistent with the text of the Clean Air Act. Furthermore, even if efficiency measures identified in the energy assessment were actually implemented, the reduced demand for the output of a regulated source is not an "emission control" technology to limit emissions from the regulated source. CAA §112(c)(2); 42 U.S.C. § 7412(d)(3). In addition, by defining the energy assessment

as a control, with the goal of reducing energy use, EPA illegally attempts to reduce demand for the product of the regulated source, in this case, the boiler. The scope of the energy assessment is illegally broad, and the proposed amendments to the scope in the Proposed Reconsidered rule do not cure the illegality. The energy assessment lacks a relationship to HAP reduction, and EPA provides no record basis demonstrating such a relationship. The rule irrationally assumes cost savings from projects that may (or may not) be identified or ever implemented by sources.

Section 114. Even as EPA proposes to not require sources to submit the energy assessment report to EPA under §112, EPA asserts in the proposed reconsidered Area Source rule, "the authority to obtain the energy assessment as authorized by section 114," 76 Fed. Reg. 80,540.

As CIBO has noted in earlier comments, the scope of the assessment is illegally broad. As proposed in the Reconsidered Rule, it remains as such, requiring sources to consider, inter alia, the "operating characteristics of the facility, energy system specifications, operating and maintenance procedures, and unusual operating constraints . . .;" "major energy consuming systems;" "available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage . . .;" and to identify "major energy conservation measures." 76 Fed. Reg. 32,014; *see also* 76 Fed. Reg. 80,664. EPA's authority under §112 is limited to setting emission limits for the affected combustion unit and does not extend to non-§ 112 sources, or generally to the entire "facility." What EPA requires goes far beyond its §112 authority.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3457-A2, excerpt 12.

This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Bruce A. Steiner

Commenter Affiliation: American Coke and Coal Chemical Institute (ACCCI)

Document Control Number: EPA-HQ-OAR-2002-0058-3547-A2

Comment Excerpt Number: 11

Comment: The Reconsidered Rule Should Not Mandate Energy Assessments Energy conservation measures are laudable and a core part of everyday life in the cokemaking industry. In fact, many cokemaking facilities already perform many of the investigations associated with an energy assessment as they have implemented the EnergyStar guidelines for energy management. Nevertheless, as explained throughout this section, EPA lacks the statutory authority to mandate facility-wide energy assessments for at least three reasons: (1) the energy assessment is not an "emission standard," (2) EPA may not reach beyond the defined source category to impose legal obligations, and (3) EPA has not demonstrated that the proposed energy assessment requirement is a cost-effective beyond-the-floor standard. Further, even if such a requirement was legally viable, there are serious implementation issues that would impair the viability and functionality of energy assessments in many instances. Section 112 of the CAA does not authorize EPA to mandate that each facility housing a boiler or process heater perform an energy assessment. The

Reconsidered Rule characterizes this energy assessment requirement as a beyond-the-floor regulation issued pursuant to the agency's authority under §112(d)(2). That provision, however, only authorizes EPA to promulgate "emission standards," which are carefully defined in CAA §302(k) to mean: A requirement ... which limits the quantity, rate, or concentration of emissions of air pollutants on a continuous basis, including any requirement relating to the operation or maintenance of a source to assure continuous emission reduction, and any design, equipment, work practice or operation standard promulgated under this chapter." 42 U.S.C. §7602(k). The proposed energy assessment requirement falls beyond that definition.

The proposed energy assessment would require an "in-depth energy study identifying all energy conservation measures appropriate for a facility given its operating parameters." Thus, that measure just mandates an evaluation of the facility's processes to "identify energy conservation measures ... that can be implemented to reduce the facility energy demand..." (emphasis added). That one-time identification of possible emission reductions and process changes will not "limit the quantity, rate or concentration of emissions of air pollutants," much less "on a continuous basis." Nor is the proposed energy assessment a "design, equipment, work practice or operation standard." As such, it falls beyond the defined concept of an "emission standard." In fact, the U.S. Court of Appeals for the DC Circuit has held that a regulation imposing a general duty, without numerical emissions limits and without a mandatory plan for implementation, was not a free-standing emission limit and thus "not a section 112-compliant standard." *Sierra Club v. EPA*, 551 F.3d 1019, 1025-1028 (D.C. Cir. 2008). That same rationale applies here and confirms that the proposed energy assessment does not meet the threshold definition of an emission standard. As such, it is beyond EPA's authority under §112 to promulgate such a requirement.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3457-A2, excerpt 12.

This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Bruce A. Steiner

Commenter Affiliation: American Coke and Coal Chemical Institute (ACCCI)

Document Control Number: EPA-HQ-OAR-2002-0058-3547-A2

Comment Excerpt Number: 13

Comment: The proposed energy assessment requirement exceeds that focused statutory charge to develop emissions standards by reaching far beyond the "specific portion" of the facilities identified in EPA's §112(c) list. Specifically, the proposed energy assessment would require the inspector to "establish operating characteristics of the facility, energy system specifications, operating and maintenance procedures, and unusual operating constraints," "review ... available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage," and facilities containing major sources must develop a "facility energy management program" in accordance with the EnergyStar energy management program. Additionally, the inspector is to "identify major energy consuming systems" and "list major energy conservation measures." *Id.* The inspector must then write up a comprehensive report summarizing his findings. *Id.* The only step properly limited to the regulated source category is the first one: "a visual inspection of the boiler system." *Id.* This step stands in stark contrast to the others, as it is

the only one explicitly limited to the regulated source category. Save the first requirement of visually inspecting the boiler, the entire energy assessment requirement attempts to regulate operations beyond the defined source category. EPA clearly lists the source categories subject to §112(d) and the Reconsidered Rule adheres to that same limitation by stating that it applies to industrial, commercial, and institutional boilers and process heaters. Nowhere is the source category defined as the facility that operates these units. Having defined the scope of this source category in its §112(c)(1) listing, EPA may not now reach beyond that category to impose obligations and limits. See *New Jersey v. EPA*, 517 F.3d 574, 583 (D.C. Cir. 2008) (“EPA may not construe [a] statute in a way that completely nullifies textually applicable provisions meant to limit its discretion.”) (quoting *Whitman v. Am. Trucking Ass’ns*, 531 U.S. 457, 485 (2001)). As such, EPA may not require the conduct of facility-wide energy assessments or the implementation of findings made during such an assessment. Instead, §112 limits EPA to regulating the source itself, in this case boilers and process heaters.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3457-A2, excerpt 12.

This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Bruce A. Steiner

Commenter Affiliation: American Coke and Coal Chemical Institute (ACCCI)

Document Control Number: EPA-HQ-OAR-2002-0058-3547-A2

Comment Excerpt Number: 14

Comment: The proposed energy assessment requirement is not cost-effective, particularly for complex steelmaking facilities with cokemaking operations. For beyond17 the-floor controls, §112(d)(2) requires EPA to take “into consideration the cost of achieving ... emission reduction[s] and any non-air quality health and environmental impacts and energy requirements” which EPA “determines is achievable for new or existing sources in the category or subcategory to which such emission standard applies...” Thus, EPA must balance the cost of implementing pollution control measures with the magnitude of the reductions that will be achieved. As an initial matter, the cost estimates in the Reconsidered Rule significantly underestimate the magnitude of conducting an energy assessment at large, complex manufacturing facilities like integrated steel mills. Our industries’ extensive experience in voluntarily working to reduce energy consumption indicates that conducting the energy assessment described in the Reconsidered Rule at an integrated mill would be exceedingly costly - exclusive of the significant time and effort that plant personnel would need to dedicate to the task. Given our industries’ existing focus on securing voluntary energy reductions, that significant expenditure would be duplicative and wasteful in many cases.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3457-A2, excerpt 12.

This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Tangelia Niemann

Commenter Affiliation: Texas Commission on Environmental Quality (TCEQ)

Document Control Number: EPA-HQ-OAR-2002-0058-3594-A3

Comment Excerpt Number: 4

Comment: The TCEQ is aware that the EPA is only proposing to amend certain definitions associated with the energy assessment requirements. However, the TCEQ does not consider it appropriate for the EPA to mandate energy efficiency assessments via a NESHAP rule. The energy assessment in 40 CFR 63 Subpart DDDDD is not a work practice or operational standard, and is not within the EPA's regulatory authority under FCAA, Section 112. Requiring companies to evaluate possible improvements in their operations does not constitute an actual work practice. Commenters challenged the EPA's authority on this requirement in the original proposal. The EPA's responses to these comments (76 FR 15631 – 15633) were that improvements in energy efficiency that reduce fuel use would reduce emissions, the requirement to perform an assessment was an enforceable requirement in the rule, and the EPA assumed that companies would implement those recommendations from the energy assessment auditor that they believed to be prudent. The EPA's responses to these comments fail to address the fundamental flaws in the EPA's beyond-the-floor argument for the energy assessment.

Foremost, the EPA is not correct in its claim that the energy assessment is a measure identified in FCAA, Section 112(d)(2) under the category of measures that "reduce the volume of, or eliminate emissions of, such pollutants through process changes, substitution of materials or other modifications..." (76 FR 15632). A reduction in fuel use would constitute such a measure; however, a requirement to conduct an evaluation of possible energy efficiency improvements that might reduce fuel use is not a measure included in FCAA, Section 112(d)(2). Furthermore, while the energy assessment is an enforceable requirement in the rule, the rule does not (and should not) require implementation of any aspect of the energy assessment. Therefore, the actual measure that could reduce emissions is not enforceable and the EPA cannot maintain that the requirement to perform an energy assessment results in emission reductions as provided in FCAA, Section 112(d)(2).

Response: See the response to comment EPA-HQ-OAR-2002-0058-3457-A2, excerpt 12.

This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Tangela Niemann

Commenter Affiliation: Texas Commission on Environmental Quality (TCEQ)

Document Control Number: EPA-HQ-OAR-2002-0058-3594-A3

Comment Excerpt Number: 5

Comment: The EPA's claim that measures that conserve steam use from the boiler would reduce emissions through fuel savings might be correct in some cases but is not necessarily true in all cases. For example, a company may be able to expand operations as a result of the improved efficiency and not actually decrease the operating rates of the boiler. Any presumed benefit from the energy assessment is based on the assumption that companies will implement some of the measures as well as assumptions of the companies' future actions. The EPA's justification for the "beyond the floor" determination that the energy assessments will result in additional emission reductions is based solely on the EPA's assumptions. Furthermore, the

EPA's claim that the costs associated with the energy assessments are "minimal, in most cases," and implementation of any cost-effective conservation measures would be partially offset by fuel savings as part of its "beyond the floor" determination (75 FR 32026) is speculative and not valid. The technical support documents for the rule indicate the cost of an energy assessment ranges from \$2,000 - \$5,000 for a commercial or institutional facility and up to \$75,000 for an industrial facility. Total annualized costs for the facility energy assessments are estimated to be \$28 million nationwide for 40 CFR 63 Subpart DDDDD and while the energy assessment may lead to emission reductions, in and of itself, the assessment does not reduce emissions. Further, even if the assessment leads to emission reductions, the EPA cannot reliably quantify emission reductions associated with the energy assessment. Additionally, efficiency improvements are not always possible. A company could spend up to \$75,000 for an energy assessment only to learn that no additional improvements in efficiency at the facility are possible. As a result, companies that are already efficient in their operations are more likely to incur the costs of the required energy assessment with little or no benefit in terms of cost savings and little or no potential emissions reductions.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3457-A2, excerpt 12.

This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Allison Watkins, Baker Botts

Commenter Affiliation: Class of '85 Regulatory Response Group

Document Control Number: EPA-HQ-OAR-2002-0058-3608-A1

Comment Excerpt Number: 13

Comment: Even if EPA had the authority to require an energy assessment of components beyond the boiler and process heater, which it does not, EPA has not substantiated that such "beyond the floor" control is warranted. In order to go "beyond the floor," EPA must consider the cost of achieving the emission reduction and the "beyond the floor" control must reduce the volume or eliminate emissions of HAPs. EPA has failed to satisfy these requirements.

Instead of considering the costs of achieving emissions reductions through the energy assessment requirement, EPA simply concludes without analysis or justification that "the costs of any energy conservation improvement will be offset by the cost savings in lower fuel costs." This assumes, first, that a facility will discover energy-saving strategies during the assessment, and, second, that the facility will be able to implement those strategies. Given that many companies already actively assess their energy usage, and that many business considerations must be evaluated before making process or equipment changes to address energy usage, both assumptions are arbitrary and irrational. EPA's consideration of the costs of achieving emissions reductions is therefore conclusory and not grounded in fact.

EPA also has failed to demonstrate that the performance of an energy assessment will result in any emissions reductions. EPA requires that facilities conduct an energy assessment, but not that they implement any of the assessment recommendations.²⁷ An assessment alone will not result in any emission reductions, disqualifying it as a "beyond the floor" control option. In its attempt to link the energy assessment requirement to emission reductions, EPA says only that "the

energy assessment will generate emission reductions through the reduction in fuel use beyond those reductions required by the floor.”EPA does not even attempt to explain (and indeed, cannot do so) how an *assessment* requirement, without an *implementation* requirement, will generate emission reductions. EPA further acknowledges that the implementation of assessment recommendations (and, therefore, the resulting emission reductions) is purely speculative: “the record indicates that energy assessments reduce fuel consumption and that parties will implement recommendations from an auditor *that they believe are prudent*.”EPA fails to link the assessment directly to a reduction in the emissions of HAPs.

For these reasons, EPA has not justified the energy assessment as a “beyond the floor” control and the requirement should be eliminated.

[Footnote 27: Requiring sources to implement the recommendations would be outside the scope of EPA’s § 112 authority because the boiler systems and energy use systems are not part of the affected source.]

Response: See the response to comment EPA-HQ-OAR-2002-0058-3457-A2, excerpt 12.

This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Randal G. Oswald
Commenter Affiliation: Integrys Energy Group
Document Control Number: EPA-HQ-OAR-2002-0058-3659-A2
Comment Excerpt Number: 9

Comment: Integrys opposes the requirement that facilities complete a one-time energy assessment on portions of a facility outside the boiler and process heater. EPA does not have the authority under §112 to impose this requirement, and even if it did, it has not demonstrated that such “beyond the floor” controls are warranted.¹¹

[Footnote]

(11) In the event that EPA retains the energy assessment requirement, it should create an exemption for units under 10 mmBtu/hr and limited use units. Given the small amount of emissions from these sources, application of the requirement would not be cost-effective.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3457-A2, excerpt 12.

This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Randal G. Oswald
Commenter Affiliation: Integrys Energy Group
Document Control Number: EPA-HQ-OAR-2002-0058-3659-A2
Comment Excerpt Number: 10

Comment: Integrys requests that EPA eliminate the requirement that facilities complete a one-time energy assessment to identify cost-effective energy conservation measures for the boiler system and its energy use systems located at the source. EPA does not have the authority under §112 to go beyond the sources listed in a source category and impose requirements on other aspects of a facility.

EPA is a federal agency; it has no constitutional or common law existence or authority, but only the authority conferred upon it by Congress. "If there is no statute conferring authority, a federal agency has none."¹² Section 112 of the Act is designed to limit HAP emissions from specific emission units that are listed under §112(c)(1). EPA is required to promulgate "emissions standards under subsection (d)" for each category and subcategory listed under §112(c)(1).¹³ The methodology for establishing emissions standards for each source category is laid out in §112(d); it authorizes the Agency to promulgate "[e]missions standards...*applicable to new or existing sources.*"¹⁴

[Footnotes]

(12) *Michigan v. EPA*, 268 F.3d 1075, 1083 (D.C. Cir. 2001).

(13) 42 U.S.C. § 7412(c)(2).

(14) 42 U.S.C. § 7412(c)(2).

Response: See the response to comment EPA-HQ-OAR-2002-0058-3457-A2, excerpt 12.

This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Randal G. Oswald

Commenter Affiliation: Integrys Energy Group

Document Control Number: EPA-HQ-OAR-2002-0058-3659-A2

Comment Excerpt Number: 12

Comment: Even if EPA had the authority to require an energy assessment of components beyond the boiler and process heater, which it does not, EPA has not substantiated that such "beyond the floor" control is warranted. In order to go "beyond the floor," EPA must consider the cost of achieving the emission reduction and the "beyond the floor" control must reduce the volume or eliminate emissions of HAPs.²¹ EPA has failed to satisfy these requirements.

Instead of considering the costs of achieving emissions reductions through the energy assessment requirement, EPA simply concludes without analysis or justification that "the costs of any energy conservation improvement will be offset by the cost savings in lower fuel costs."²² This assumes, first, that a facility will discover energy-saving strategies during the assessment, and, second, that the facility will be able to implement those strategies. Given that many companies already actively assess their energy usage, and that many business considerations must be evaluated before making process or equipment changes to address energy usage, both assumptions are arbitrary and irrational. EPA's consideration of the costs of achieving emissions reductions is therefore conclusory and not grounded in fact.

EPA also has failed to demonstrate that the performance of an energy assessment will result in any emissions reductions. EPA requires that facilities conduct an energy assessment, but not that they implement any of the assessment recommendations.²³ An assessment alone will not result in any emission reductions, disqualifying it as a "beyond the floor" control option. In its attempt to link the energy assessment requirement to emission reductions, EPA says only that "the energy assessment will generate emission reductions through the reduction in fuel use beyond those reductions required by the floor."²⁴ EPA does not even attempt to explain (and indeed, cannot do so) how an *assessment* requirement, without an *implementation* requirement, will generate emission reductions. EPA further acknowledges that the implementation of assessment recommendations (and, therefore, the resulting emission reductions) is purely speculative: "the record indicates that energy assessments reduce fuel consumption and that parties will implement recommendations from an auditor *that they believe are prudent*."²⁵ EPA fails to link the assessment directly to a reduction in the emissions of HAPs.

For these reasons, EPA has not justified the energy assessment as a "beyond the floor" control and the requirement should be eliminated.

[Footnotes]

(21) 42 U.S.C. § 7412(d)(2).

(22) 75 Fed. Reg. at 32026.

(23) Requiring sources to implement the recommendations would be outside the scope of EPA's § 112 authority because the boiler systems and energy use systems are not part of the affected source.

(24) 76 Fed. Reg. at 15632.

(25) 76 Fed. Reg. at 15632 at 15633 (emphasis added).

Response: See the response to comment EPA-HQ-OAR-2002-0058-3457-A2, excerpt 12.

This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 74

Comment: Comments on the energy assessment requirement.

A. The beyond-the-floor energy assessment requirement is not justified and should be deleted.

The proposal to impose a facility-wide energy assessment through this rulemaking is not practical, overstates benefits, understates costs, and is not authorized by the CAA. Since the energy assessment requirement impacts units other than BPH in a facility by including energy

consuming systems, this rulemaking expands this BPH rulemaking to many other source categories. The Agency's authority under section 112 of the CAA for that expansion is unclear at best.

There is no basis to claim any benefits for the energy assessment requirement since 1) major sources typically have already performed extensive energy assessments and installed those projects with high economic returns that make sense from a safety, reliability, operability and capital management perspective, and 2) the proposal separately requires BPH tune-ups, EPA's claimed main source of energy assessment benefits. In fact, EPA claims that the separate tune-up requirement saves 1% of the fuel fired from every BPH subject to that requirement, which is the majority of BPH (In Table 5 of the preamble EPA indicates 11,911 BPH in the gas 1 subcategory out of a total of 14,111 existing BPH). Thus, there are likely no net benefits from performing the energy assessment.

Our experience is that assessments such as specified in this proposal cost a minimum of \$100,000 for even a simple, small refinery and usually quite a lot more and require a large team of engineers intimately familiar with the site. While costs might be much lower for smaller facilities if they can avail themselves of the proposed 8 hour and 24 hour limit on assessment hours, there is no chance of any benefits in those cases, since 8 and 24 hours is inadequate to meet the assessment requirements as outlined in Table 3 or to certify compliance (See the following comment).

In refinery operations, many of energy "efficiencies" meeting the proposed definition of a "cost effective energy conservation measure" would not be manageable because of their operational or reliability impacts. Others would not be achievable because they would require capital that is required for mandated safety and environmental projects. Finally, many such measures would simply result in the transference of emissions to outside the refinery boundary and increase overall national emissions. One example is the shutdown of a steam turbine (presumably decreasing refinery emissions) and replacing it with an electric driver (transferring the emissions outside the boundary of the refinery) and increasing US emissions overall.

The current proposal appears to have considered a few minor points from our reconsideration request but certainly does not indicate any serious reconsideration of the energy assessment requirement. Nothing in the proposal or proposal preamble addresses 1) the legality of imposing this requirement on sources outside the regulated source category (i.e., energy consumers), 2) how this assessment is linked to HAP emissions, the legal basis for this rulemaking (which are miniscule from gas and light liquid fired equipment), 3) how equipment reliability, safety, and operability are to be protected, 4) the impact on national emissions of the transference of energy production to locations outside of our operations, or 5) the real costs of the proposal.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3457-A2, excerpt 12.

This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Samuel H. Bruntz

Commenter Affiliation: Alcoa Power Generating, Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3755-A1

Comment Excerpt Number: 16

Comment: Proposed regulation 63.7500 and Table 3 requires that a one-time energy assessment must be performed. Alcoa- Warrick acknowledges that performance of an energy assessment would be a prudent business decision, but strongly objects to the inclusion of an energy assessment requirement in a regulation that regulates hazardous air pollutants. MACT floor determinations for this source category did not consider energy assessments. Thus, inclusion of the energy assessment requirement in this proposed regulation is contrary to the Clean Air Act. Accordingly, Alcoa-Warrick requests that item 4 of Table 3 and the definition of Energy Assessment listed in 63.7575 be removed from the proposed regulation.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3457-A2, excerpt 12.

This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 81

Comment: Energy usage within most manufacturing facilities is directly and inextricably related to the processes being used and the qualities of the specific products being produced. The sweeping language EPA has proposed to modify manufacturing processes out of concern for HAP and non-HAP emissions would grant EPA the authority to redesign proprietary and confidential manufacturing systems at industrial sites across the country. This would require many, if not most, industrial facilities to grant third-party auditors and EPA access to a highly Confidential Business Information (CBI). Neither third-party auditors nor EPA fully understand the myriad technical and commercial analyses developed over years, or in some cases decades, by companies to optimize energy consumption, product performance and quality, and safety. This would paradoxically create a regulatory vehicle that would allow EPA the authority to mandate changes in energy-consuming manufacturing processes without first developing the in-house expertise to understand the full breadth of the processes, and with it the impact of potential changes to the safety of employees, competitive advantage of the product, or upstream and downstream processing activities at integrated sites.

Response: The energy assessment requirement of the Boiler MACT does not proposed to modify manufacturing processes or, in fact, grant the EPA the authority to redesign proprietary and confidential manufacturing systems. The revision made to the final rule allows company employees to conduct the actual energy assessment and the scope has been clarify to cover only the affected boilers and process heaters and the on-site systems using the energy from the affected boilers and process heaters. As for the authority to require an energy assessment, see the response to comment EPA-HQ-OAR-2002-0058-3457-A2, excerpt 12.

This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Shannon S. Broome
Commenter Affiliation: Auto Industry Forum (AIF)
Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1
Comment Excerpt Number: 47

Comment: EPA fails entirely to address the points previously raised by AIF. First, the energy assessment is impermissible under Section 112 of the CAA because the assessment is not an "emission standard" and it does not operate to reduce HAP emissions. EPA does not and cannot demonstrate that merely conducting an energy assessment will actually reduce HAP emissions or even that implementing the findings of such an assessment will lead to reduction in HAP emissions. EPA should eliminate the assessment on that ground alone. If EPA elects to retain the assessment, however, it exceeds EPA's authority under the CAA, even with the revision to certain language in Table 3. The energy assessment still operates to regulate sources beyond those strictly in the source category, *i.e.*, those not regulated by the Boiler MACT. The Boiler MACT does not regulate manufacturing facilities as a whole, therefore, EPA cannot properly include a variety of systems throughout facilities beyond the boilers and process heaters themselves. Therefore, to the extent it elects to retain the assessment, EPA should curtail the assessment to apply only to the boiler and/or process heater, not to the broader range of processes at a plant.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 81.

This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1
Comment Excerpt Number: 112

Comment: Energy usage within most manufacturing facilities is directly and inextricably related to the processes being used and the qualities of the specific products being produced. The sweeping language EPA has proposed to modify manufacturing processes out of concern for HAP and non-HAP emissions would grant EPA the authority to redesign proprietary and confidential manufacturing systems at industrial sites across the country. This would require many, if not most, industrial facilities to grant third-party auditors and EPA access to a highly Confidential Business Information (CBI). Giving EPA the authority to mandate changes to manufacturing processes would put at risk competitive advantages that many manufacturers have secured for their products through careful technical and commercial analysis. Neither third-party auditors nor EPA fully understand the myriad technical and commercial analyses developed over years, or in some cases decades, by companies to optimize energy consumption, product performance and quality, and safety. This would paradoxically create a regulatory vehicle that would allow EPA the authority to mandate changes in energy-consuming manufacturing processes without first developing the in-house expertise to understand the full breadth of the

processes, and with it the impact of potential changes to the safety of employees, competitive advantage of the product, or upstream and downstream processing activities at integrated sites.

EPA has authority to regulate HAP emissions from major sources under section 112(d) of the Clean Air Act. This attempt to further regulate the way major sources consume energy under this rule is beyond EPA's authority. EPA should eliminate its definitions of "boiler system" and "energy use system". EPA should further limit the scope of energy assessments to "boiler(s)" and "process heater(s)" as currently defined.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 81.

This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Stephen E. Woock

Commenter Affiliation: Weyerhaeuser Company

Document Control Number: EPA-HQ-OAR-2002-0058-3523-A1

Comment Excerpt Number: 14

Comment: EPA continues to propose an "above the floor" requirement to require facilities to conduct energy assessments. EPA's concept is in general, that by identifying cost-effective energy conservation measures, HAP emission would be reduced if some of the measures are implemented. Weyerhaeuser stridently opposes this proposed provision. While under the right circumstances there may be some merit to the general concept of conducting energy assessments to identify ways to reduce energy use and thereby reduce HAP emissions, EPA's proposal continues to miss the mark as an inefficient redundancy of a differently structured non-voluntary process that will potentially disrupt our continuing internal program and participation in voluntary efficiency programs. We refer EPA to our previous comments on this in docket ID EPA-HQ-OAR-2002-0058-2797 and the comments by our trade groups.

Response: Based on discussion with stakeholders, we are aware that some facilities may participate in a voluntary energy efficiency program or have recently conducted an energy assessment which a required additional energy assessment would be an unnecessary redundancy. The final rule has been revised to exempt owners and operators of affected boiler and process heaters that are in a energy efficiency program provided that the affected boilers and process heaters are included in the energy efficiency program. This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

104B. Five Year Time Frame [DENIED PETITIONER ISSUE]

Commenter Name: Michael Livermore, Jason Schwartz

Commenter Affiliation: Institute for Policy Integrity, NYU School of Law

Document Control Number: EPA-HQ-OAR-2002-0058-3432-A1

Comment Excerpt Number: 7

Comment: EPA's rule requires a one-time energy assessment for certain existing boilers. Mandatory energy assessments can be justifiable to correct market failures, and that justification can extend beyond a one-time energy audit for existing boilers only. Audits should be periodically repeated and should also apply, at appropriate times, to new boilers. More importantly, regulated entities should be required to implement any cost-effective energy conservation measures identified.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Michael Livermore, Jason Schwartz

Commenter Affiliation: Institute for Policy Integrity, NYU School of Law

Document Control Number: EPA-HQ-OAR-2002-0058-3432-A1

Comment Excerpt Number: 10

Comment: The final regulation should also require an energy assessment for new sources several years after they come into existence. Even assuming a reason to exempt new sources when they first come online, the distinction between "new" sources and existing sources will diminish over time. After the passage of several years, conditions will change compared to when a new facility was originally designed. Markets and technologies evolve. If interest rates drop (and thus the related discount rates), more projects may become cost-effective. If expected fuel prices increase, the financial return from a given quantity of energy savings will be higher. Existing technologies may become cheaper. New technologies will increase the number of projects to consider. All of these changes mean that new sources may no longer be optimized after several years of operation.

The energy assessments of existing sources will become out of date on a similar timeframe. A new set of cost-effective energy conservation measures could be discovered every few years as a result. Thus, for both new and existing sources, audits should be periodic. This should be achievable at relatively low cost because much of the initial work would be done on the first assessment and would not need to be repeated.

Repeated energy assessments will also provide an easy mechanism for verification and enforcement of the required implementation of previously identified cost-effective conservation measures. If the regulated entity has not implemented their required energy conservation measures, this failure will turn up in subsequent energy assessments.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Lee Zeugin and Lauren Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1

Comment Excerpt Number: 9

Comment: UARG argued in its comments on the 2010 proposed rule that the energy assessment requirement exceeded EPA's legal authority and that it should be removed from the

final rule. UARG remains convinced that CAA § 112(d) only authorizes EPA to regulate “sources” of HAP emissions.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

104C. Cost Analysis [DENIED PETITIONER ISSUE]

Commenter Name: Jessica Bridges

Commenter Affiliation: United States Clean Heat & Power Association (USCHPA)

Document Control Number: EPA-HQ-OAR-2002-0058-3501-A1

Comment Excerpt Number: 13

Comment: USCHPA questions the limitation to rely on a two-year or less payback criterion. Many capital investments, including combined heat and power systems, typically have longer payback periods, considering all benefit streams (both thermal and electricity). This should be reconsidered and broadened to permit greater aggregation of benefit streams. For example, Federal, State and even local tax credits should be applied to the benefit side of the calculation.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: David Gardiner

Commenter Affiliation: The Alliance for Industrial Efficiency

Document Control Number: EPA-HQ-OAR-2002-0058-3683-A2

Comment Excerpt Number: 6

Comment: EPA Should Refine Its Engineering Cost Analysis to Account for Savings Identified in the Energy Assessment.

While the Rule does not mandate implementation of cost-effective measures identified in the energy assessments, EPA properly notes that facilities are likely to implement many of the identified improvements. EPA acknowledged this likelihood in the March Rule, noting "while we do not know the precise reductions that will occur at individual sources, the record indicates that energy assessments reduce fuel consumption and that parties will implement recommendations from an auditor that they believe are prudent." It also implicitly recognizes the potential for regulated facilities to implement recommendations from the energy assessments in the December Rule, providing instructions for facilities that seek to "take credit for implementing energy conservation measures identified in an energy assessment." Despite this recognition, the Engineering Cost Analysis simply accounts for the cost of performing energy assessments, without accounting for potential savings that may result.²¹

The Engineering Cost Analysis should be modified to reflect conservative assumptions about potential fuel savings (and associated emissions reductions) that would result from implementing the results of the energy assessment.

[Footnote 21:US Environmental Protection Agency, OAQPS, Feb. 2011, “Regulatory Impact Analysis: National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters,” at 3-3 (Table 3-1) (http://www.epa.gov/ttn/ecas/regdata/RIAs/boilersriafinal110221_psg.pdf) (note that this estimate is unchanged in the Dec. 2011 Memorandum from Tom Walton to Brian Shrager, “Regulatory Impact Results for the Reconsideration Proposal for National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters at Major Sources” (<http://www.epa.gov/ttn/atw/boiler/boilersriaproposalrecon111201.pdf>)).]

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

104D. Definition of “Cost Effective” [DENIED PETITIONER ISSUE]

Commenter Name: Michael Livermore, Jason Schwartz

Commenter Affiliation: Institute for Policy Integrity, NYU School of Law

Document Control Number: EPA-HQ-OAR-2002-0058-3432-A1

Comment Excerpt Number: 3

Comment:

For some existing major and area sources, EPA has proposed requiring an "energy assessment" to identify "a list of energy conservation measures." While the regulations do not require implementation of any of the energy conservation measures identified, they do define "cost-effective energy conservation measures" as any measure with "a payback (return of investment) period of two years." EPA now seeks comments on the scope and definition of the required energy assessments.

The definition of "cost-effective measures" in the rule is fatally flawed statutorily and unjustified economically. If implementation of these measures is not required, there is arguably no need to define "cost-effective," and thus no definition should be issued. But since implementation of these measures is cost-benefit justified and should be required (see *infra*, section III of these comments), properly defining "cost-effective energy conservation measures" becomes important. The proper definition for that term should be: any energy conservation measure whose net present benefits are greater than zero.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Michael Livermore, Jason Schwartz

Commenter Affiliation: Institute for Policy Integrity, NYU School of Law

Document Control Number: EPA-HQ-OAR-2002-0058-3432-A1

Comment Excerpt Number: 4

Comment: The definition of "cost-effective" chosen by EPA is improper for many reasons. There is no need for EPA to look to the Energy Policy and Conservation Act (EPCA) to define "cost-effective" under the Clean Air Act, and there are important differences between the statutes. The definition of "achievable" under Section 112(d) (and thus the subsidiary definition of "cost-effective" if the agency is to require implementation of "cost-effective energy conservation measures") should be based on the statutory text and purposes of the Clean Air Act and not on any part of the EPCA. In addition, the definition chosen by EPA is an improper interpretation of the clause from the EPCA that the agency looked to for guidance. The general context of the EPCA indicates that the clause sets a *floor* for "economically justified" and is not an independently valid definition of the term. Moreover, it is clear from the EPCA that Congress intended "economically justified" to mean cost-benefit justified.

The agency maintains that its definition—"a payback period of two years"—is based on section 325(o)(2)(B)(iii) of the Energy Policy and Conservation Act of 1975.¹⁰ The originally proposed rules' preamble explains that under this section "there is a presumption that an energy conservation standard is economically justified if the increased installed cost for a measure is less than three times the value of the first-year energy savings resulting from the measure."¹¹

First, it is not clear how the agency justifies reading the phrase "three times the value of the first year energy savings" under the EPCA to indicate a two-year payback period. These calculations are distinct in obvious ways.

Second, this interpretation omits crucial parts of the EPCA's statutory scheme. The full text of the cited clause from the EPCA is as follows:

If the Secretary [of Energy] finds that the additional cost to the consumer of purchasing a product complying with an energy conservation standard level will be less than three times the value of the energy, and as applicable, water, savings during the first year that the consumer will receive as a result of the standard, as calculated under the applicable test procedure, there shall be a rebuttable presumption that such standard level is economically justified. A determination by the Secretary that such criterion is not met shall not be taken into consideration in the Secretary's determination of whether a standard is economically justified.¹²

The final sentence of this clause indicates that a finding that a standard does not meet the criterion cannot even be taken into consideration for whether the standard is "economically justified." Thus, the definition chosen by EPA for "cost-effective" is inappropriate even within the context of the clause they cite to support it.

Third, the cited clause only makes sense in the context of EPCA's Section 325(o)(2)(A):

Any new or amended energy conservation standard prescribed by the Secretary under this section for any type (or class) of covered product shall be designed to achieve the maximum improvement in energy efficiency . . . which the Secretary determines is technologically feasible and economically justified.¹³

In this context, it is clear that the section cited by EPA as justification for the definition of "cost-effective" explicitly sets a floor for the Secretary of Energy's determination of "technologically feasible and economically justified," and is not a reasonable definition of "economically justified" or "cost-effective" by itself. More generally, Congress intended "economically justified" to mean cost-benefit justified, because the statute requires the Secretary of Energy to "determine whether the benefits of the standard exceed its burdens."¹⁴

Ultimately, the EPCA is not an appropriate place to look for a definition under the Clean Air Act at all. First, there are no statutory terms within the relevant sections of Clean Air Act that refer to the EPCA. Second, there is no duplication of statutory terms where proper interpretation would suggest that meanings should be harmonized across the statutes.¹⁵ For example, the EPCA uses "technologically feasible and economically justified" and then lays out criteria to guide the Secretary of Energy for making determinations based on that phrase.¹⁶ None of those criteria or terms is repeated in the Clean Air Act. For purposes of an energy assessment under Section 112(d) of the Clean Air Act, EPA should apply the statutory language of the Clean Air Act and standard economic principles, not the EPCA.

[Footnote 10: Codified at 42 U.S.C. § 6295 (2010).]

[Footnote 11: 75 Fed. Reg. at 32,026.]

[Footnote 12: 42 U.S.C. § 6295(o)(2)(B)(iii).][Footnote 14: 42 U.S.C. § 6295(o)(2)(B)(i).]

[Footnote 15: *See, e.g.,* W.V. University Hospitals, Inc. v. Casey, 499 U.S. 83, 100-101 (1991) (looking to other statutes to determine the definition of "attorney's fees").]

[Footnote 13: 42 U.S.C. § 6295(o)(2)(A).]

[Footnote 16: 42 U.S.C. § 6295(o)(2)(B)(i)(I)-(VII): "(I) the economic impact of the standard on the manufacturers and on the consumers of the products subject to such standard; (II) the savings in operating costs throughout the estimated average life of the covered product in the type (or class) compared to any increase in the price of, or in the initial charges for, or maintenance expenses of, the covered products which are likely to result from the imposition of the standard; (III) the total projected amount of energy, or as applicable, water, savings likely to result directly from the imposition of the standard; (IV) any lessening of the utility or the performance of the covered products likely to result from the imposition of the standard; (V) the impact of any lessening of competition, as determined in writing by the Attorney General, that is likely to result from the imposition of the standard; (VI) the need for national energy and water conservation; and (VII) other factors the Secretary considers relevant."]

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Michael Livermore, Jason Schwartz

Commenter Affiliation: Institute for Policy Integrity, NYU School of Law

Document Control Number: EPA-HQ-OAR-2002-0058-3432-A1

Comment Excerpt Number: 5

Comment: The proposed definition of "cost-effective energy conservation measure" is "a measure that is implemented to improve the energy efficiency of the boiler or facility that has a payback (return of investment) period of two years or less." By implicitly limiting the criteria to the private costs and benefits for regulated parties, this definition clearly falls short of the authority EPA has under the best interpretation of the statute. Because EPA has authority to consider a fuller range of social costs and benefits in determining which beyond-the-floor regulations are "achievable" under Section 112(d), the definition of "cost-effective" could include social costs and benefits.

However, as a practical matter, EPA will likely continue to exercise its statutory authority to stay focused on private costs and benefits in defining "cost-effective" for these purposes. An energy audit focused on private costs and benefits can still be a crucial element of a broader suite of regulatory policies designed to maximize net social welfare and minimize the negative impacts of hazardous air pollution. As such, these comments will explore how best to define "cost-effective" considering only private costs and benefits.

Given that it makes sense to define "cost-effective" in this context as reflecting private costs and benefits, it also makes sense to evaluate these costs and benefits in the way that an economically rational firm would value them. This means that all benefits and costs from a project should be considered, and a firm should undertake all investments where the net present value of all costs and benefits is higher than zero.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Michael Livermore, Jason Schwartz

Commenter Affiliation: Institute for Policy Integrity, NYU School of Law

Document Control Number: EPA-HQ-OAR-2002-0058-3432-A1

Comment Excerpt Number: 6

Comment: There are two important practical elements in determining the net present value of private investments: the timeframe of the analysis, and the discount rate for future costs and benefits.

The proper period of analysis for evaluating an investment is the period during which the investment affects relevant parties. The Economic Analysis Resource Document published by EPA's Office of Air Quality Planning and Standards states that:

It is common practice to calculate the costs of a regulatory option over the period of time corresponding to the expected useful lifetime of capital equipment purchased to comply with the rule. For example, if the capital equipment purchased as a result of the rule has an expected useful life of 15 years, an analyst might calculate the expected costs of the rule over a 15-year period. For consistency, benefits should be calculated over the same 15-year period.¹⁹

This rule of thumb should be used here as well. In the case of energy conservation measures, the "useful lifetime" of the project is the period when it provides benefits to the regulated party.

Because many (if not all) of the energy conservation measures being considered will have beneficial effects lasting longer than two years, EPA is unnecessarily limiting the consideration of benefits by defining the payback period as two years. Incorporating the full upfront costs of the measures but ignoring substantial future benefits would lead to under-adoption of energy conservation measures.²⁰ Given that the statutory explanation chosen by EPA for the two-year payback period is severely deficient, the agency should instead select the project's useful lifetime as the more economically rational period for analyzing energy conservation measures.

The discount rate is also important because it will determine how many measures will have a net present value above zero. In the context of an investment like an energy conservation measure, the costs of implementation will often be frontloaded and the benefits will be fairly constant from year to year (assuming fairly even amounts of energy savings and relatively stable prices). As a result, fewer energy conservation measures will look cost-effective with higher discount rates. For private investment decisions, the proper discount rate is the opportunity cost of capital, on the assumption that any dollar spent could earn the rate of return that the entity is achieving in its other projects. The correct rate will be the risk-adjusted rate of return that would be used to evaluate similar investment projects.²¹

[Footnote 19: OFFICE OF AIR QUALITY PLANNING AND STANDARDS, EPA, OAQPS ECONOMIC ANALYSIS RESOURCE DOCUMENT at 8-1(1999).]

[Footnote 20: Assuming that most capital costs are incurred in the early years of the project.]

[Footnote 21: The standard formulation would include the risk-free rate of return, plus an adjustment for the variance of the rate of return on the project. The risk of the particular energy conservation measure will be driven by volatility in energy prices or uncertainty in the actual quantity of energy savings.]

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Michael Livermore, Jason Schwartz

Commenter Affiliation: Institute for Policy Integrity, NYU School of Law

Document Control Number: EPA-HQ-OAR-2002-0058-3432-A1

Comment Excerpt Number: 8

Comment: Ample evidence shows that businesses do not always take advantage of all cost-effective investments at their facilities. For example, a McKinsey & Company report from 2007 discovered many un-adopted greenhouse gas reduction measures that would have a negative marginal cost for private actors.²² Many of the measures identified in that report were available to the same the industrial and commercial sectors covered by EPA's Major Source and Area Source rules. EPA notes that the Department of Energy has done energy assessments and discovered that some facilities can reduce energy use by 10 to 15 percent.²³

The requirement of an energy assessment partially solves this problem. While somewhat controversial, Professor Michael Porter and others have argued that certain types of regulations can have negative costs, by forcing firms to rethink their production processes.²⁴ In this case, the

energy assessment requirement will provide each regulated entity with information it did not have before. New and better information can help overcome organizational inertia by giving evidence of cost-savings. A mandatory energy assessment, rather than a voluntary program, can be justified due to persistent barriers to the voluntary pursuit of energy efficiency—lack of information, lack of attention and salience, prioritization, and so forth.

The energy assessment requirement is a cost-benefit-justified regulation even if implementation of identified conservation measures is not mandatory. Armed with better information and focused attention thanks to an energy audit, regulated sources will be better able to take advantage of opportunities with significant private financial benefits, not to mention the environmental and health benefits from cutting energy use and associated pollution. While it is possible that some assessments may not lead to identifying of efficient energy efficient projects at some sources, there is sufficient evidence of general under-adoption of energy efficient technologies in the relevant sectors that substantial cost-savings can be achieved through the assessment requirement.

[Footnote 22: MCKINSEY & COMPANY, REDUCING U.S. GREENHOUSE GAS EMISSIONS: HOW MUCH AT WHAT COST? (2007), *available at* http://www.mckinsey.com/clientservice/sustainability/pdf/US_ghg_final_report.pdf.]

[Footnote 23: 75 Fed. Reg. at 32,026.]

[Footnote 24: See David Popp, Richard G. Newell & Adam B. Jaffe, *Energy, the Environment, and Technological Change* (NBER Working Paper No. 14832, Apr. 2009); Michael E. Porter & Claas van der Linde, *Towards a New Conception of the Environment Competitiveness Relationship*, 4 J. ECON. PERSPECTIVES 97, 99 (1995).]

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: David Gardiner

Commenter Affiliation: The Alliance for Industrial Efficiency

Document Control Number: EPA-HQ-OAR-2002-0058-3683-A2

Comment Excerpt Number: 5

Comment: EPA Should Make the Energy Assessment Requirement More Robust By Expanding the Definition of Cost-Effective Energy Efficiency Improvements.

The Alliance is very supportive of the energy assessment requirement in the Rule. Such a requirement will enable regulated entities to lower compliance costs while reducing emissions of both hazardous and conventional pollutants. We are gratified by the broad scope of the energy assessment requirement and concur with EPA’s finding in the March 21, 2011 Rule that its inclusion of all major energy-consuming systems (and not merely the regulated boilers) will have substantial benefits. As we noted in our Reconsideration Petition, however, EPA should reconsider the definition of "cost effective" in the Rule in order to encourage regulated entities to identify more energy-saving opportunities.

In the March 21, 2011 rule, EPA defined "Cost-effective energy conservation measure" to mean "a measure that is implemented to improve the energy efficiency of the boiler or facility that has a payback (return of investment) period of 2 years or less." This definition remains unchanged in the December rule. Because such assessments are required of all existing major source facilities having affected boilers or process heaters, the scope of such an assessment is a fundamental element of the Rule. As written, we believe that the Assessment is too limited and the definition should therefore be changed to allow for a more comprehensive consideration of energy efficiency improvements at the regulated source. The current standard excludes some highly cost-effective measures that could generate substantial emissions reductions.

In particular, while delivering tremendous and cost-effective efficiency gains (and, therefore, emission reductions), CHP and WHR facilities require significant up-front expenditures.¹⁷ EPA in numerous other contexts has noted the enormous efficiency potential from CHP and WHR projects.¹⁸ The Alliance, therefore, reiterates its request for EPA to include language within its final rule that expressly encourages energy assessments that highlight the potential for CHP and WHR without imposing a two-year payback limitation.

[Footnote 17: See, e.g., Anna Chittum and Nate Kaufman, American Council for an Energy Efficient Economy, Sept. 2011, Report No. IE111: "Challenges Facing Combined Heat and Power Today: A State-by-State Assessment," at 6 (available online at <http://aceee.org/research-report/ie111>) (reporting capital costs for CHP projects ranging from \$700 to \$3,000 per installed kilowatt).]

[Footnote 18: See, e.g., EPA Combined Heat and Power Partnership website (<http://www.epa.gov/chp/>).]

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

104E. Energy Assessors Determine Time [DENIED PETITIONER ISSUE]

Commenter Name: Tangela Niemann

Commenter Affiliation: Texas Commission on Environmental Quality (TCEQ)

Document Control Number: EPA-HQ-OAR-2002-0058-3594-A3

Comment Excerpt Number: 14

Comment: The criteria that the EPA is proposing for a person to be considered a *qualified energy assessor* are overly specific and may force businesses to incur additional costs to conduct the energy assessment. The EPA is attempting to create a definition of *qualified energy assessor* that encompasses a broad range of industrial and commercial applications by establishing specific criteria for capabilities and knowledge. However, the effect is that owners and operators of sources will be required to contract a person meeting all the criteria in the EPA's definition to perform an energy assessment regardless of the application, rather than have the assessment performed by a person with the most specific knowledge for the application. Many of the facilities subject to 40 CFR 63 Subpart DDDDD are large industrial facilities, and some of these companies will have their own personnel that are much more knowledgeable about the operations at the facility. However, the EPA's definition of *qualified energy assessor* may force a company to contract an outside assessor because the company's own staff don't meet the specific criteria of the definition in §63.7575, even if the criteria are unrelated to operations at the facility. If the energy assessment is retained in the final rule, the definition of *qualified*

energy assessor should be made more general or revised such that the assessor is only required to have knowledge and capabilities specific to the processes at the site.

Response: The definition of "Qualified energy assessor" in the final rule has not been revised because it does prevent in-house experts from performing and preparing the energy assessment report.

This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Rationale for Regulated Pollutants

6A. Appropriateness of Work Practice for Dioxins/Furans

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 44

Comment: The work practice standards EPA has proposed consist of an annual "tune-up," a "one-time energy assessment," and "good combustion practices." 76 Fed. Reg. at 80,664. Even if § 112(h) authorized EPA to set work practice standards in lieu of emission standards for boilers' emissions of dioxins and organic HAPs – which it does not – these work practice standards contravene § 112(h)(1), which provides that such standards must be "consistent with the provisions of subsection (d) or (f) of this section." 42 U.S.C. § 7412(h)(1). To be consistent with § 112(d), any work practice standards for boilers would have to reflect measures that yield the maximum achievable degree of reduction in these pollutants and that at a minimum reflect the measures adopted by the boilers with the lowest emission levels of dioxins and organic HAPs. EPA's proposal does not purport to satisfy this requirement and is untenable in light of record evidence that boilers can and do achieve reductions in dioxins through the use of activated carbon injection and reductions in other organic HAPs through the use of selective catalytic reduction systems. Further, as EPA is well aware, boiler operating parameters other than those mentioned in the proposed rule, 76 Fed. Reg. at 80,664, have a significant effect on dioxin emissions. In particular, EPA's previous MACT rules including its standards for medical waste incinerators show that the agency knows perfectly well that the composition of the fuel/waste being burned, temperature of the boiler combustion chamber, the residence time in the combustion chamber, the temperature of the gas exiting that chamber, the rapidity of the cooling of the gas, and the temperature of the air pollution control device all have significant effects on dioxin emissions. EPA, Chlorinated Dioxin and Furan Formation, Control and Monitoring (1997), Ex. 3 hereto. Assuming *arguendo* that EPA can set work practice standards at all for boilers' emissions of dioxins and other organic pollutants (and that the agency can set work practice standards for gas fired units and units with a relatively low capacity), these standards must be "consistent with the provisions of § 112(d)" by requiring the use of these control measures. Because EPA's proposed standards do not require the use of such measures they contravene § 112(h). Because EPA has not shown how its work practice standards comply with § 112(h) or even attempted to explain how they are consistent with § 112(d) given that many

boilers use control measures that reduce emissions of dioxins and other organic pollutants other than those contained in its proposed work practice standards, the agency's decision to promulgate such standards would be arbitrary and capricious.

Response: The EPA believes that the work practices being finalized for dioxins are appropriate and are consistent with the statute and with other NESHAP rulemaking efforts. Further, each source category is addressed individually and, although EPA strives for consistency in its approach, there are times where different approaches for different source categories are warranted. EPA took a different approach in the MWI rule, because section 129 requires that standards promulgated applicable to solid waste incineration specify numerical emission limitation and does not contain authority for work practice standards. Further, the emission limits for dioxins in the MWI rule are, in many cases, an order of magnitude higher than the dioxin levels measured (or the detection level for non-detects) from boilers and process heaters. EPA disagrees with the commenter's assertion that the work practice standard is not justified under section 112(h). That provision authorizes EPA to establish work practice standards for sources if the Agency determines that it is not feasible to prescribe or enforce an emissions standard. In this case, EPA has determined that it is not feasible to do so because the application of measurement methodology is impracticable due to technological and economic limitations. First, as explained in the preamble to the proposed reconsideration rule, the majority of emissions of dioxins for all subcategories of boilers and process heaters are below the detection levels of EPA test methods and, therefore, are technologically impracticable to measure. In addition, economic limitations make the application of measurement methodology impracticable because of the increased sampling time, manpower, and analyses in order to achieve measurement practicality. EPA also disagrees with the commenter's assertion that the work practice standard is inconsistent with section 112(d). The EPA understands that emissions of most organic HAP can be minimized by maintaining good combustion conditions. Furthermore, the EPA understands the other factors that affect dioxin emissions noted by the commenter, as cited in the record for EPA's 1997 emissions standards for medical waste incinerators, including the composition of the material being combusted and the conditions under which the material is combusted. However, we disagree that the 1997 analysis is relevant to today's action, because of differences between boilers and incinerators. Boilers are designed for high and nearly complete combustion whereas incinerators are designed primarily to reduce the volume of the organic waste material being feed, and the material combusted in a medical waste incinerator contains chlorinated plastics which is not part of the fuel burned in any boiler covered by the Boiler MACT. Thus, the factors that affect dioxin emissions, applicable to non-waste burning boilers, cited by the commenter can be controlled by and are part of the work practice standard that ensure boilers and process heaters are operated under good combustion conditions.

We continue to believe that the work practice standard that requires routine boiler/burner maintenance is the best measure for limiting emissions of dioxins from boilers and process heaters covered by the Boiler MACT, and it is justified consistent with CAA section 112(h). We disagree with the commenter suggestion that additional work practices are needed. Boilers are designed to routinely operate under the combustion conditions that will minimize dioxin emissions. This is confirmed by the fact that most of the dioxin emission test results obtained on boilers covered by the Boiler MACT are at or below the detection level.

Therefore, based on the combustion environment among boilers and process heaters, the requirement to conduct a periodic tune-up reflects the maximum degree of emissions reduction available, and is therefore consistent with section 112(d). The tune-up requirement will ensure that owners and operators of affected units verify combustion optimization and yet allow each unit to optimize combustion according to the best practice for the boiler type.

The work practice standard is a practical approach to ensuring that equipment is maintained and run so as to minimize emissions of dioxins, and we expect it to be more effective than establishing a numeric standard that cannot reliably be measured or monitored. The work practice requires maintaining and inspecting the burners and associated combustion controls (as applicable), tuning the specific burner type to optimize combustion, obtaining and recording CO, oxygen, and NOx (if applicable) values before and after the burner adjustments, keeping records of activity and measurements, and submitting a report for each tune-up conducted.

We disagree with the commenter that there is record evidence that boilers (non-waste burning) can and do achieve reduction in dioxin through the use of activated carbon injection (ACI) and selective catalytic reduction (SCR). ACI may have been demonstrated on medical waste incinerators (MWI) and municipal waste combustors (MWC) to reduce dioxins but they emit significantly higher dioxins due to incinerating chlorinated plastics. Further, we have no emission data showing the effect of ACI or SCR on controlling dioxin emissions from industrial (non-waste burning) boilers and the commenter did not submit this “record evidence” for units in this source category.

Commenter Name: Elizabeth McMeekin

Commenter Affiliation: PPG Industries, Inc

Document Control Number: EPA-HQ-OAR-2002-0058-3778-A1

Comment Excerpt Number: 8

Comment: PPG supports a work practice approach for dioxin/furan emissions from industrial boilers. Dioxin/Furan emissions cannot be reliably measured and there is no technically feasible means of ensuring continuous control of these emissions.

EPA has very little data on dioxin/furan emissions from industrial boilers and process heaters. In addition to the lack of actual data, the science is uncertain on how dioxin/furan emissions are formed and could be controlled from industrial boilers and process heaters. (Docket item EPA-HQ-OAR-2002-0058-02871 contains an extensive discussion on this subject.) While industry has experience controlling dioxin/furan emissions from sources such as municipal waste combustors where dioxin/furan emissions occur at much higher levels, there is no data showing that dioxin/furan emissions can be controlled using add-on control technology at the ultra low levels reported by boiler/process heater sources in the industrial boiler MACT ICR testing program.

Quantifying the actual, extremely low or non-existent dioxin emission levels for the Industrial Boiler MACT floor units is technologically impracticable and thus, it is not feasible to prescribe or enforce an emission standard for dioxin/furan emissions for these units. Therefore, EPA has ample authority and justification under Clean Air Act Section 112(h)(1) to establish a work practice standard for dioxin/furan in the Boiler MACT, as was done in the recently finalized

Mercury and Air Toxics Standard (MATS, or EGU MACT). The required tune-ups and other emissions reductions in the Industrial Boiler MACT will result in improved combustion and minimize dioxin/furan formation without establishing a numerical emission standard.

[Footnote]

(1) Chlorinated Dioxin and Furan Formation, Control, and Monitoring, Presented at an ICCR Meeting, September 17, 1997.

Response: The EPA thanks the commenter for their support.

Commenter Name: Felix Mestey, on behalf of Donald R. Schregardus

Commenter Affiliation: Clean Air Act Services Steering Committee, Department of Defense (DoD)

Document Control Number: EPA-HQ-OAR-2002-0058-3427

Comment Excerpt Number: 19

Comment: As noted by EPA in its proposed reconsideration of the final Boiler NESHAP, there are no demonstrated emission control technologies that would reduce D/F emission levels identified in the final rule. EPA's proposed approach will result in D/F emission reductions in a cost-effective and technically appropriate manner.

Recommendation. DoD supports EPA's proposal to apply work practice standards instead of numeric emission limits for D/F.

Response: The EPA thanks the commenter for their support.

Commenter Name: Lee Zeugin and Lauren Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1

Comment Excerpt Number: 2

Comment: As EPA correctly notes, there are no proven emission controls for reducing dioxin and furan emissions below the already low levels indicated by IB testing. The work practice standards proposed by EPA will ensure efficient combustion practices and will avoid unnecessary and expensive compliance testing by IB operators.

Response: The EPA thanks the commenter for their support.

Commenter Name: David A. Buff, Golder Associates Inc.

Commenter Affiliation: Florida Sugar Industry (FSI)

Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1

Comment Excerpt Number: 4

Comment: The FSI supports a work practice standard that requires an annual boiler tune-up. The annual tune-up will help ensure good combustion in the boiler, which will in turn help minimize dioxin/furan emissions. Conversely, the FSI is not aware of any commercially

available technology that will reduce dioxin/furan emissions from biomass-fired boilers to levels that are lower than the ones reported in the EPA database for the Proposed Boiler MACT Rule.

For all of these reasons, EPA's proposed work practice standard for dioxin/furan is more appropriate for the FSI's bagasse fired boilers than a numeric emission limit.

Response: The EPA thanks the commenter for their support.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 7

Comment: Based on the record supporting the Final Boiler Rule, EPA has very little data on dioxin/furan emissions from industrial boilers and process heaters since the majority of emission measurements are below the level that can be accurately measured using Method 23.

Furthermore, the science is still uncertain on how dioxin/furan emissions are formed and could be controlled from industrial boilers and process heaters. An extensive discussion on the subject can be found in the Docket.³ Industry has experience controlling dioxin/furan emissions from sources such as municipal waste combustors where dioxin/furan emissions occur at much higher levels than those reported by boiler/process heater sources in the industrial boiler MACT ICR testing program. [Footnote 3: Docket ID EPA-HQ-OAR-2002-0058-0287 Chlorinated Dioxin and Furan Formation, Control, and Monitoring, Presented at an ICCR Meeting, September 17, 1997.]

Response: The EPA acknowledges this comment.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 8

Comment: There is no data showing that dioxin/furan emissions at ultra-low levels can be controlled using add-on control technology. The comments submitted by the National Council for Air and Stream Improvement (NCASI) on the 2010 Proposed Boiler Rule, provided significant support on this point.⁴ Their comments specifically focused on method detection and quantitation limit issues, and demonstrated that the proposed standards are below the 95th percentile of practical quantitation limits achieved over all tests. Comments submitted by the Dow Chemical Company, also provided technical support on this issue.⁵

[Footnote 4: Docket ID EPA-HQ-OAR-2002-0058-2804]

[Footnote 5: Docket ID EPA-HQ-OAR-2002-0058-2632]

Response: The EPA acknowledges this comment.

Commenter Name: Stephen E. Woock
Commenter Affiliation: Weyerhaeuser Company
Document Control Number: EPA-HQ-OAR-2002-0058-3523-A1
Comment Excerpt Number: 1

Comment: We support EPA's decision to establish a tune-up work practice to replace the dioxin and furan limits of the March 2011 final rules. This approach will eliminate concerns with technical infeasibility of controls to meet the limits proposed in 2010 and finalized in 2011. The EPA has responded reasonably and legally to the clear information that the limits were confounded by measurement uncertainties at the very low levels in the emissions database, as would be compliance measurements and strategies for control options.

Response: The EPA thanks the commenter for their support.

Commenter Name: Paul Noe
Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.
Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1
Comment Excerpt Number: 1

Comment: EPA has Correctly Determined That a Work Practice Standard, Rather Than an Emission Limit, is Appropriate for Dioxin/Furan (D/F)

The majority of the data collected in order to set the D/F standards for industrial boilers are at levels below the capability of the analytical and stack test methods to detect emissions of these compounds (all but one of the test runs used to set the March 2011 Boiler MACT limits are marked as "detection level limited"). Much of the test data are labeled as being below the method detection limit and the remainder of the data is often flagged as being below the level the laboratory can report with confidence.

It is not appropriate to treat detection level limited data for purposes of establishing regulatory limits in the same manner as detected values because the uncertainty¹⁹ associated with measurements near or below the method detection limits is too high. The test methods were developed over 30 years ago to measure D/F at concentrations then found in some types of waste incinerator exhaust (levels orders of magnitude higher than those found in exhaust from today's industrial boilers).

All source emission measurements have random (precision) errors associated with sample collection, sample and equipment handling, sample preparation, and sample analysis. These errors define method detection and quantitation limits and uncertainty in a non-arbitrary, scientific manner (as discussed further below). When emission levels are much higher than the magnitude of these errors, there is a high degree of confidence in the measured value obtained from a single or a few test runs. However, as the measured value decreases, the contribution of these errors to the measured value increases, thus decreasing the confidence level in the accuracy of the measured value from a single or a few runs until the point where the measured value cannot be distinguished from the random error ("noise" level). This is the case with the boiler D/F data. When this occurs, the measurement value cannot be distinguished from zero with high confidence.

The magnitude of D/F measurement errors typically varies with every measurement and is affected by the characteristics of the sample, skills of the sampler and analyst, specific equipment used, techniques and procedures adopted by individual laboratories and other factors, even when following the same published test method (in this case, EPA Method 23). Although EPA Method 23 procedures minimize measurement errors at the stack emission levels and applications for which it was intended, measurement errors are not zero and become significant at the extremely low levels in industrial boilers.

Response: The EPA thanks the commenter for their support.

Commenter Name: Douglas A. McWilliams

Commenter Affiliation: American Municipal Power

Document Control Number: EPA-HQ-OAR-2002-0058-3685-A2

Comment Excerpt Number: 22

Comment: In both the final Utility MACT rule and the proposed Boiler MACT rule, EPA acknowledged that dioxin/furan exists in quantities too low to be accurately measured or detected by EPA Method 23, and that no known control technologies have a demonstrated ability to further reduce dioxin/furan below these already miniscule levels.²⁷ According to EPA's Boiler MACT analysis, more than half of the dioxin/furan measurements reviewed for purposes of setting the MACT floor were below the method detection level, and for several subcategories (including stoker coal units) all of EPA's data is below the level that can be accurately measured. These findings are consistent with EPA's findings in the Utility MACT rule, in which EPA acknowledged that the presence of sulfur in the exhaust gases prevents the formation of dioxins and furans in quantities greater than the detection limit, specifically when the sulfur-to-chlorine ratio in the gas is greater than 1.0. This ratio will exist for coal-fired boilers almost across the board.²⁹ The same analysis applicable to coal-fired Utility MACT boilers is applicable to the smaller coal-fired utility boilers subject to Boiler MACT operated by AMP members.

[Footnote 27: *See* 76 Fed. Reg. at 80606; 77 Fed. Reg. at 9369.]

[Footnote 29: *See* 76 Fed. Reg. 24976, 25023 (May 3, 2011).]

Response: The EPA acknowledges this comment.

Commenter Name: Russell A. Wozniak

Commenter Affiliation: The Dow Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3449-A1

Comment Excerpt Number: 5

Comment: Dow supports EPA's decision to establish a work practice for dioxin/furan emissions.

Establishing a work practice standard for dioxin/furan emissions is supported by the emissions information collected by EPA. As detailed in our August, 2010 comments on the proposed rule, we shared similar concerns to those of EPA that the proposed numerical emission limits were below the method of detection and/or a level that can be accurately measured using EPA Method

23. Page 80606 of the December 23, 2011 preamble correctly points out the emission measurement problems and supports establishing work practice standards for these HAP. This proposed action is also consistent with EPA's recently promulgated MACT rule for electric utility boilers.

Response: The EPA thanks the commenter for their support.

Commenter Name: Melvin E. Keener

Commenter Affiliation: Coalition for Responsible Waste Incineration (CRWI)

Document Control Number: EPA-HQ-OAR-2002-0058-3454-A1

Comment Excerpt Number: 6

Comment: At 76 Fed. Reg. 80606, EPA explains that the majority of dioxin/furan data is below the detection limit. As such, the Agency made the decision to set work practice standards for dioxin/furans instead of numerical emission standards. CRWI supports that decision. Section 112(h) of the Clean Air Act allows the use of work practice standards when "the application of measurement technology...is not practicable due to technological and economic limitations." Not being able to reliably measure a pollutant certainly qualifies as a technology limitation. In addition, it is practically impossible to properly quantify the variability as a part of setting a floor standard when the majority of the data is below the detection limit.

Response: The EPA thanks the commenter for their support.

Commenter Name: Traylor Champion

Commenter Affiliation: Georgia-Pacific LLC (GP)

Document Control Number: EPA-HQ-OAR-2002-0058-3465-A1

Comment Excerpt Number: 3

Comment: GP supports EPA's decision to regulate dioxin / furan emissions from boilers and process heaters using a work practice standard established under Section 112(h) of the CAA as a result of the impracticality of establishing numerical limits: analytical quantification limitations for these pollutants make setting emissions limits impractical. As EPA states in the proposed rule, a very high percentage actual dioxin / furans measurements were below the level that can be accurately measured and therefore establishing a standard is not practicable due to technological and economic limitations. GP has conducted follow-up dioxin testing on a number of boilers to fully understand our emission profiles. In this follow-up testing, we have found that nearly all of the dioxin tests results were impacted by non-detectable levels of dioxin and furans. Our experience with dioxin testing is consistent with EPA's conclusion that it is impractical to measure dioxin / furans at the low levels found in industrial boilers emissions due to analytical limitations and imprecision in the sampling and testing procedures.

GP agrees with EPA's use of a work practice and we believe the work practice option is not only appropriate but the only available means of demonstrating compliance with dioxin / furan requirements.

Response: The EPA thanks the commenter for their support.

Commenter Name: Claudia M. O'Brien, Latham & Watkins LLP
Commenter Affiliation: JELD-WEN, inc.
Document Control Number: EPA-HQ-OAR-2002-0058-3485-A1
Comment Excerpt Number: 1

Comment: EPA has proposed work practice standards instead of numeric emission limits for dioxin/furans because its reassessment of the dioxin/furan data sets revealed that a majority of emission measurements were below the method detection level (MDL).² EPA explained that it adopted the work practice standards approach for dioxin/furans in its Utility MACT rule, and that rule and the Boiler MACT rule had similar data. In reassessing the Boiler MACT data, EPA found that approximately 55 percent of the measurements were below the MDL.³ Additionally, a much higher percentage of measurements for each subcategory were below the level that can be accurately quantified—more than half of the subcategories had 100 percent of measurements below the accurate measurement level, and the remaining subcategories had more than 80 percent of measurements below that level.⁴ Based upon this data analysis, EPA concluded that dioxin/furan emissions in industrial boilers and process heaters "cannot practically be measured."

[Footnote 4: The percentages of measurements below the level that can accurately be quantified are: 100 percent for Coal stoker; 89 percent for coal fluidized bed; 85 percent for pulverized coal; 100 percent for biomass stoker/other; 100 percent for biomass fluidized bed; 80 percent for biomass dutch oven/pile burner; 100 for biomass fuel cell; 96 percent for heavy liquid; 100 percent for light liquid; 100 percent for gas 2 (other process gases); and 100 percent for non-continental liquid (based on No. 6 oil data). EPA did not have data available for two of the biomass subcategories. 76 Fed. Reg. at 80,606.]

EPA's proposal to adopt work practice standards for dioxin/furan emissions is entirely consistent with EPA's practice in the context of other rules. In the Utility MACT proposal, EPA noted that "measurements made at or below the MDL have an accuracy on the order of plus or minus 50 percent, whereas other environmental measurements used by EPA in other rulemaking exhibit accuracies of plus or minus up to 15 percent."⁶ The Utility MACT data collection effort confirmed that the majority of testing showed data at or below the MDL, even where the testing time was doubled.⁷ EPA therefore concluded that it was questionable that any amount of expense and effort would make the tests viable.⁸ Thus, since the majority of emission measurements from electric generating units were below detection levels and the reliability of these dioxin/furan measurements presented both technological and economic obstacles to demonstrating compliance, EPA set work practice standards rather than emission standards for dioxin/furan in the Utility MACT proposal and finalized those standards in the Utility MACT rule. The Boiler MACT data similarly proves that industrial boilers face comparable technological and economic obstacles to demonstrating compliance, as dioxin/furan measurements are not reliable for these sources either.

[Footnote 7: 76 Fed. Reg. 24,976,25,040 (May 3, 2011) (Proposed Utility MACT Rule) (sampling time for

the 2010 Information Collection Request was extended to 8 hours)]

[Footnote 8: 76 Fed. Reg. 24,976,25,040 (May 3, 2011) (Proposed Utility MACT Rule) (sampling time for

the 2010 Information Collection Request was extended to 8 hours)]

Response: The EPA thanks the commenter for their support.

Commenter Name: Robert E. Hunzinger

Commenter Affiliation: Gainesville Regional Utilities (GRU), Florida

Document Control Number: EPA-HQ-OAR-2002-0058-3488-A1

Comment Excerpt Number: 3

Comment: GRU supports the provision that would eliminate emission limits for dioxin and furans and would impose work practice standards to minimize dioxin/furan emissions, which consist of a periodic tune-up to ensure good combustion is achieved and maintained.¹

[Footnote]

(1) In the preamble of the reconsideration rule proposal EPA acknowledged that 55% of all data collected was below the detection limits for dioxin and furans

Response: The EPA thanks the commenter for their support.

Commenter Name: Michael Bradley

Commenter Affiliation: The Clean Energy Group

Document Control Number: EPA-HQ-OAR-2002-0058-3495-A1

Comment Excerpt Number: 1

Comment: Based on additional data and analysis, EPA acknowledged that direct measurement of dioxin/furan emissions is impractical, as was found for the Mercury and Air Toxics Standards (MATS). Thus, EPA proposes a work practice standard of an annual tune-up to ensure good combustion. The Clean Energy Group supports this change and agrees that the extensive measurement times and potential measurement inaccuracies warrant the use of a work practice standard. An annual tune-up to ensure good combustion is a reasonable measure to minimize emissions.

Response: The EPA thanks the commenter for their support.

Commenter Name: Lee Zeugin and Lauren Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1

Comment Excerpt Number: 1

Comment: UARG supports EPA's proposal to establish work practice standards in lieu of numeric emission limits for dioxin and furan emissions. Section 112(h) grants EPA discretion to set work practice standards in place of emission limits if the Administrator finds it is not feasible to prescribe or enforce emission limits. CAA § 112(h)(1). In the reconsideration notice, EPA

provides persuasive evidence about the very high percentage of non-detect measurements for dioxin and furan emissions from all categories of IBs. This is hardly surprising because IB operators have a strong economic incentive to operate their units as efficiently as possible.

The high percentage of measurements below the detection limit makes setting a meaningful MACT limit impossible for these HAPs because, by definition, a measurement below the detection limit has greater error associated with it than the value measured. In other words, one cannot say for sure that the substance is even present. Furthermore, setting an emission limit at the detection limit would be unenforceable because the error associated with a compliance measurement would make it impossible to certify the accuracy of a measurement. Setting an emission limit three times higher than the detection limit would only impose expensive dioxin testing with no practical value, since all future measurements are likely to be below that limit. Therefore, it is feasible neither to prescribe nor to enforce dioxin emission standards for IB units.

Response: The EPA thanks the commenter for their support.

Commenter Name: David A. Buff, Golder Associates Inc.

Commenter Affiliation: Florida Sugar Industry (FSI)

Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1

Comment Excerpt Number: 3

Comment: FSI strongly supports EPA's decision to promulgate a work practice standard, in lieu of a numerical standard, for dioxin/furan emissions from biomass-fired boilers. There is little dioxin/furan data available to use for the establishment of a numerical emission limit for biomass-fired boilers, especially the hybrid suspension grate boilers and cell-type boilers used by the FSI. EPA concluded that "the large majority of the emissions measurements [for dioxin/furan] for all of the subcategories [of boilers] are below the level that can be accurately measured." 76 F.R. at 80606. EPA specifically noted that this conclusion is true with regard to several categories of biomass fired boilers. Consequently, it would be extremely difficult or impossible to establish a scientifically defensible limit for the dioxin/furan emissions from biomass fired boilers.

Response: The EPA thanks the commenter for their support.

Commenter Name: Michael L. Krancer

Commenter Affiliation: Pennsylvania Department of Environmental Protection (DEP)

Document Control Number: EPA-HQ-OAR-2002-0058-3507-A1

Comment Excerpt Number: 3

Comment: The EPA has proposed applying work practice standards for dioxins/furans in lieu of numeric emission limits for all boiler subcategories. The work practice standards require an annual tuneup, in accordance with § 63.7540, to ensure good combustion. The EPA reassessed the dioxin/furan data sets and determined that the large majority of the emission measurements for all subcategories are below the level that can be accurately measured by using the approved EPA test method. The EPA concluded that dioxin/furan emissions for all of the subcategories cannot be accurately measured using EPA Method 23.

The DEP agrees that dioxin/furan emissions cannot be accurately measured for certain subcategories. The DEP supports the inclusion of work practice standards, including an annual tune-up. This should provide adequate public protection by ensuring good combustion. The work practice standards approach would also alleviate the costly expenditures (a minimum of \$13,000 per test for EPA Method 23) that would be incurred for the performance of stack tests for dioxins/furans.

Response: The EPA thanks the commenter for their support.

Commenter Name: Chris M. Hobson

Commenter Affiliation: Southern Company

Document Control Number: EPA-HQ-OAR-2002-0058-3520-A1

Comment Excerpt Number: 7

Comment: As noted in Southern Company's comments⁴ on the proposed Industrial Boiler MACT, EPA does not have sufficient data above the detection limit to establish emission standards for dioxins and furans. Southern, therefore, supports EPA proposed decision to establish work practices standards in accordance with CAA § 112(h) as it is not practicable to apply the relevant measurement methodology to non-detect emissions.

[Footnote]

(4) Southern Company comments to Docket ID No. EP A-HQ-OAR-2002-0058 dated August 23, 2010

Response: The EPA thanks the commenter for their support.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 2

Comment: As demonstrated by the measurement issues noted, quantifying the actual, extremely low or non-existent dioxin emission levels for the Boiler MACT floor units is technologically impracticable (as well as economically impracticable, given that the technological problems cannot be overcome by investing reasonable resources into the problem), and thus, it is not feasible to prescribe or enforce an emission standard for D/F emissions for these units. Therefore, EPA has ample authority and justification under Clean Air Act Section 112(h)(1) to establish a work practice standard for D/F in the Boiler MACT, as was done in the recently finalized MATS rule²⁴. The required tune-ups and other emissions reductions in the Industrial Boiler MACT will result in improved combustion and minimize conditions conducive to D/F formation without establishing a numerical emission standard. Again, we support EPA's conclusion in this proposal to establish work practice standards for D/F from industrial boilers.

[Footnote 24: 77 Fed. Reg. 9369 ("We are finalizing work practice standards [for organic HAP, including dioxins and furans] because the significant majority of data for measured organic HAP emissions from EGUs are below the detection levels of the EPA test methods....").]

Response: The EPA thanks the commenter for their support.

Commenter Name: Richard Krock

Commenter Affiliation: The Vinyl Institute

Document Control Number: EPA-HQ-OAR-2002-0058-3526-A1

Comment Excerpt Number: 1

Comment: Work Practice Standards Are Appropriate For Controlling Dioxin Emissions

The VI supports EPA's decision to replace dioxin/furan emission limits with work practice standards for all boiler subcategories. During its reconsideration of the boiler MACT, EPA determined that a very high percentage of measurements in the data used to set the MACT floors were below the method quantitation level, *i.e.* the level at which dioxins can be accurately measured using the Agency's method for measuring dioxin emission from stationary sources—EPA Method 23. EPA concluded as a result that dioxin emissions from boilers cannot practicably be measured.

Response: The EPA thanks the commenter for their support.

Commenter Name: Richard Krock

Commenter Affiliation: The Vinyl Institute

Document Control Number: EPA-HQ-OAR-2002-0058-3526-A1

Comment Excerpt Number: 3

Comment: The detection limit of an analytical method is the lowest concentration that can be distinguished from replicate blanks.⁷ The quantitation limit of a method is the smallest concentration of the substance which can be measured with an acceptable level of uncertainty.⁸ Detection limits and quantitation limits are defined in a scientific, non-arbitrary manner in various published peer-reviewed consensus guidelines⁹ and EPA documents. Quantitation limits of test methods have great significance when measuring very low concentrations of pollutants. In practice, reported values below the method's quantitation limit should not be treated as real values. While speculation may serve a role in scientific research and exploration, such speculation is not a valid basis for imposing regulatory compliance requirements with significant legal penalties for noncompliance.

In the proposed rule, EPA has made the threshold determination that measurement of dioxin emissions from boilers is not practicable, because the data in the record shows that emission levels from boilers are in most cases below the level that can be reliably measured by the analytical methods. In the subcategories for which EPA had dioxin emission data, the percentage of measurements below the quantitation limit ranged from 80 to 100 percent. It is not surprising that the data fall below the method quantitation limit, given that the test methods were developed more than 30 years ago to measure dioxins in waste incinerator exhaust streams at concentrations that were orders of magnitude higher than those found in emissions from boilers. Given the infeasibility of measuring dioxin emissions, work practice standards are the appropriate approach.

[Footnotes]

(7) 40 C.F.R. Part 136, Appendix B; *see also* <http://www.epa.gov/ttn/emc/facts.html#lab>.

(8) EPA Method 301, 2004 version; Wisconsin DNR Analytical Detection Limit Guidance, April 1996, <http://www.dnr.state.wi.us/org/es/science/lc/outreach/publications/lod%20guidance%20document.pdf>.

(9) *See, e.g.*, L.H. Keith, et al., *Principles of Environmental Analysis*, 55 *Analytical Chemistry* 2210-2218 (1983); *see also*, Rigo, H.G. and Chandler, A.J., *Quantitation Limits for Reference Methods* 23, 26, and 29, *J. Air & Waste Manage. Assoc.* 1999, 49:399-410.

Response: The EPA thanks the commenter for their support.

Commenter Name: Bart Sponsellar

Commenter Affiliation: Wisconsin Department of Natural Resources

Document Control Number: EPA-HQ-OAR-2002-0058-3527-A2

Comment Excerpt Number: 2

Comment: EPA has proposed to eliminate emission limitations for dioxin and furans (D/F) and replace these limits with a good combustion work practice. EPA based the need for implementing a work practice based on the low levels of emitted dioxin and furans and the resulting ability to accurately quantify and set emission limitations. In taking this action, EPA recognized that low emission levels are the result of good combustion practices. EPA came to this same conclusion for electric utility boilers and also implemented dioxin and furan good combustion work practices in that rule. The Department supports EPA's conclusions.

Response: The EPA thanks the commenter for their support.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 28

Comment: CIBO supports the EPA's decision to apply work practice standards for dioxins/furans emissions instead of applying numeric emission limits. 76 Fed. Reg. 80,606 (2012 Reconsideration Rule). As CIBO stated in its Petition for Reconsideration, levels of dioxins/furans in coal-fired utility boilers are below the detection levels of the EPA test methods, and, furthermore, dioxin/furan levels in industrial boilers are similarly low. Because detection of dioxins/furans is so uncertain, CIBO urged EPA to adopt work practice standards in lieu of numeric emission limits. EPA has since "re-assessed the dioxin/furan data sets and has determined that, similar to data for electric utilities for which work practice standards were proposed for dioxins/furans, the large majority of the emission measurements for all of the subcategories are below the level that can be accurately measured using EPA Method 23. . . [T]he EPA concludes that emissions from industrial boilers and process heaters cannot practicably be measured, and the EPA is now proposing work practice standards in place of numeric emission limits for dioxin/furan." 76 Fed.Reg. 80,606 (2012 Reconsideration Rule). CIBO supports this proposal.

Response: The EPA thanks the commenter for their support.

Commenter Name: J. Michael Geers

Commenter Affiliation: Duke Energy

Document Control Number: EPA-HQ-OAR-2002-0058-3543-A1

Comment Excerpt Number: 5

Comment: Duke Energy supports the EPA's proposal to apply work practice standards for dioxins/furans emissions instead of applying numeric emission limits. 76 Fed. Reg. 80,606. In Duke Energy's experience, the levels of dioxins/furans in coal-fired utility boilers are below the detection levels of EPA's test methods, and, furthermore, dioxin/furan levels in industrial boilers are similarly low. Because detection of dioxins/furans is so uncertain, Duke Energy urged EPA to adopt work practice standards in lieu of numeric emission limits. EPA states in the IB MACT proposal that it has since "re-assessed the dioxin/furan data sets and has determined that, similar to data for electric utilities for which work practice standards were proposed for dioxins/furans, the large majority of the emission measurements for all of the subcategories are below the level that can be accurately measured using EPA Method 23. . . [T]he EPA concludes that emissions from industrial boilers and process heaters cannot practically be measured, and the EPA is now proposing work practice standards in place of numeric emission limits for dioxin/furan." 76 Fed. Reg. 80,606. Based on its own operating experience and testing, Duke Energy believes that good combustion techniques are sufficient to minimize the formation of dioxin/furans and therefore supports this proposed change.

Response: The EPA thanks the commenter for their support.

Commenter Name: Vickie Woods

Commenter Affiliation: Division of Air Quality, North Carolina Department of Environment and Natural Resources (NCDENR)

Document Control Number: EPA-HQ-OAR-2002-0058-3663-A2

Comment Excerpt Number: 18

Comment: Dioxin standard. EPA revised the procedure to calculate the final dioxin emission limits, given the proximity to the detection limits. EPA reassessed the lowest level accurately measured for dioxin emissions, compared those to the emission levels from all units tested, and found emissions were below the value accurately measured.

NC DAQ supports EPA's revised procedure for calculating a final dioxin emission limit. As mentioned above, we agree with EPA's conclusion to develop a work practice standard instead of emission limit standards, since most dioxin emissions were below the detection level.

Response: The EPA thanks the commenter for their support.

Commenter Name: Douglas A. McWilliams

Commenter Affiliation: American Municipal Power

Document Control Number: EPA-HQ-OAR-2002-0058-3685-A2

Comment Excerpt Number: 23

Comment: It is not appropriate to treat detection level limited data for purposes of establishing regulatory limits in the same manner as detected values because the uncertainty associated with measurements near or below the method detection limits is too high. All source emission measurements have random (precision) errors associated with the sample collection, sample and equipment handling, sample preparation, and sample analysis. These errors define method detection and quantitation limits and uncertainty in a non-arbitrary, scientific manner. When emission levels are much higher than the magnitude of these errors, there is a high degree of confidence in the measured value obtained from a single or a few test runs. However, as the measured value decreases, the contribution of these errors to the measured value increases, thus decreasing the confidence level in the accuracy of the measured value from a single or a few runs until the point where the measured value cannot be distinguished from the random error ("noise" level). This is the case with the boiler dioxin/furan data. When this occurs, the measurement cannot be distinguished from zero with high confidence.

Response: The EPA acknowledges this comment.

Commenter Name: Richard D. Garber

Commenter Affiliation: Boise Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3686-A2

Comment Excerpt Number: 1

Comment: Boise supports justifiable use of work practices as an alternative to dioxin and furan numeric emission limits. With data for best performers being at or below the measurement capability of the stack test methods and analytical method detection limits, compliance demonstration for numerical limits would have been technically infeasible. Establishment of work practice tune-up standards for good combustion control will assure that emissions of these pollutants are minimized the full extent possible.

Response: The EPA thanks the commenter for their support.

Commenter Name: Philip Lewis

Commenter Affiliation: Michigan Biomass - Grayling Generating Station

Document Control Number: EPA-HQ-OAR-2002-0058-3815-A1

Comment Excerpt Number: 1

Comment: A work practice standard for dioxin/furans instead of a numerical emission limit. We were quite concerned about the expense and reliable quantification of our very low emissions with the available test methods. The proposed change resolves this concern.

Response: The EPA thanks the commenter for their support.

Commenter Name: Claudia M. O'Brien, Latham & Watkins LLP

Commenter Affiliation: JELD-WEN, inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3485-A1

Comment Excerpt Number: 2

Comment: EPA's proposal to adopt work practice standards is also consistent with the agency's statutory authority. Clean Air Act (CAA) section 112(h) permits EPA to prescribe a work practice standard or other design, equipment, or operational standard consistent with CAA sections 112(d) or (f) "if it is *not feasible* in the judgment of the Administrator to prescribe or enforce an emission standard...."¹⁰ The statute further defines the phrase "not feasible to prescribe or enforce an emission standard" as including situations where the Administrator determines that "the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations."¹¹

Here, EPA made the finding required by the statute to support adoption of work practice standards-that dioxin/furan emissions "cannot practicably" be measured for these sources. ¹² Setting a work practice standard here is well within the statutory framework-and stands in sharp contrast to *Sierra Club v. EPA*, 479 F.3d 875, 884 (D.C. Cir. 2007), where the D.C. Circuit struck down EPA's adoption of a work practice standard for ceramic kilns. In that case, EPA had not made *any* finding that measuring emissions from ceramic kilns was impracticable. Rather, EPA simply did not have data. That is clearly not the case here. EPA has the dioxin/furan data, but it has properly found that the data is not reliable and there are no methods of detection that would increase reliability at this time.

Thus, EPA's decision to adopt work practice standards here is consistent with past practice and its statutory mandate, and JELD-WEN supports it.

[Footnote 10: 42 U.S.C. § 7412(h)(1) (emphasis added).]

[Footnote 11: 42 U.S.C. § 7412(h)(2)(B).]

[Footnote 12: 76 Fed. Reg. at 80,606.]

Response: The EPA thanks the commenter for their support.

Commenter Name: Lenny Dupuis

Commenter Affiliation: Dominion Resources Services, Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3486-A1

Comment Excerpt Number: 3

Comment: We strongly support EPA's decision to establish work practice standards for dioxin furans in place of the emission limits that were set in the March 2011 final rule. Section 112(h)(2)(B) of the CAA authorizes EPA to establish work practice standards when "the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations." The very stringent emission standards EPA established in the March 2011 rule for dioxin/furans for all of the source categories were based, in whole or part, on data below detection limits (non-detect values) and the technological limitations of measuring such low pollutant levels suggest that a work practice standard would be more appropriate.

Response: The EPA thanks the commenter for their support.

Commenter Name: Richard Krock
Commenter Affiliation: The Vinyl Institute
Document Control Number: EPA-HQ-OAR-2002-0058-3526-A1
Comment Excerpt Number: 2

Comment: Pursuant to Section 112(h) of the Clean Air Act, “if it is not feasible in the judgment of the Administrator to prescribe or enforce an emission standard . . . the Administrator may, in lieu thereof, promulgate a design, equipment, work practice, or operational standard.”⁵ The Agency must first make a determination that “the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations,” not that it lacks emissions data to set a limit.⁶ Boilers and process heaters present precisely the type of technological constraints in measuring for dioxins/furans that warrant, if not mandate, the use of work practice standards.

[Footnotes]

(5) 42 U.S.C. § 7412(h)(1). *See also* Sierra Club v. EPA, 479 F.3d 875, 883 (D.C. Cir. 2007).

(6) *Sierra Club v. EPA*, 479 F.3d at 883. *See also* 42 U.S.C. § 7412(h)(2)(B).

Response: The EPA thanks the commenter for their support.

Commenter Name: Matthew Todd
Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)
Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2
Comment Excerpt Number: 42

Comment: We strongly support EPA’s conclusion that the CAA 112(h) criteria are met and therefore design, equipment, work practice, or operational requirements are the appropriate and legal means of meeting the requirements of CAA section 112(d)(2) for D/F emissions, for the Gas 1 and Limited-Use subcategories and for smaller boilers and process heaters (i.e., <10 MMBTU/hr).

Response: The EPA thanks the commenter for their support.

Commenter Name: Matthew Todd
Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)
Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2
Comment Excerpt Number: 45

Comment: As EPA has now demonstrated, D/F levels generated from BPH are not accurately quantifiable and thus meet the criterion of even a conservatively interpreted section 112(h) of the CAA. Use of a design or work practice requirement is therefore not only appropriate under the provisions of the CAA, but the only available means of managing D/F emissions by a methodology where compliance can be demonstrated (i.e., records to show that the design requirement or work practice was performed.)

Response: The EPA thanks the commenter for their support.

Commenter Name: Douglas A. McWilliams

Commenter Affiliation: American Municipal Power

Document Control Number: EPA-HQ-OAR-2002-0058-3685-A2

Comment Excerpt Number: 21

Comment: A Work Practice Standard for Dioxin/Furan is Appropriate and Should Be Maintained in the Final Rule

EPA appropriately established a work practice standard for dioxin/furan instead of a numeric emission limit in the Proposed Rule . This approach is consistent with the approach taken by EPA in the recently finalized Utility MACT rule published December 16, 2011. EPA has the authority to establish a work practice standard in lieu of a numeric emission limit pursuant to CAA § 112(h): " If it is not feasible in the judgment of the Administrator to prescribe or enforce an emission standard for control of a hazardous air pollutant or pollutants, the Administrator may, in lieu thereof, promulgate a design, equipment, work practice, or operational standard, or combination thereof, which in the Administrator's judgment is consistent with the provisions of subsections (d) or (f) of this section."²⁵ The D.C. Circuit Court of Appeals has affirmed EPA's authority under CAA section 112(h) to use work-practice standards instead of emission floors where "measuring emission levels is technologically or economically impracticable."²⁶

[Footnote 25: 42 U.S.C. § 74 12(h).]

[Footnote 26: *Sierra Club v. EPA*, 479 F.3d 875, 884 (D.C. Cir. 2007).]

Response: The EPA thanks the commenter for their support.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 9

Comment: Quantifying the actual, extremely low or non-existent dioxin emission levels for the industrial, commercial, and institutional (ICI) Boiler MACT floor units is technologically impracticable (as well as economically impracticable, given that the technological problems cannot be overcome by investing reasonable resources into the problem), and thus, it is not feasible to prescribe or enforce an emission standard for dioxin/furan emissions for these units. Furthermore, on February 17, 2012, EPA released its final non-cancer science assessment for dioxins and noted that —*As a result of efforts by EPA, state governments and industry, known and measurable air emissions of dioxins in the United States have been reduced by 90 percent from 1987 levels. The largest remaining source of dioxin emissions is backyard burning of household trash.*|| Additionally, the Agency also noted that "*generally, over a person's lifetime, current exposure to dioxins does not pose a significant health risk.*"

The EPA's findings further support the Agency's justification under Clean Air Act § 112(h)(1) to establish a work practice standard for dioxin/furan in the Boiler MATS.⁶ The required tune-ups

and other emissions reductions in the final Boiler MACT will result in improved combustion and minimize conditions conducive to dioxin/furan formation without establishing a numerical emission standard.[Footnote 6: 77 Fed. Reg. 9369, February 16, 2012 ("We are finalizing work practice standards [for organic HAP, including dioxins and furans] because the significant majority of data for measured organic HAP emissions from EGUs are below the detection levels of the EPA test methods....").]

Response: The EPA thanks the commenter for their support.

Commenter Name: LESLIE SUE RITTS

Commenter Affiliation: National Environmental Development Association's Clean Air Project (NEDA/CAP)

Document Control Number: EPA-HQ-OAR-2002-0058-3529-A1

Comment Excerpt Number: 16

Comment: NEDA/CAP supports EPA's conclusion that it is not feasible to accurately measure dioxins and furans and thus a work practice standard is reasonable and appropriate. NEDA/CAP strongly supports the Agency's proposal to replace dioxin and furan emission limits with work practice standards. Section 112(d) of the Clean Air Act requires that MACT standards are limited to measures which are achievable and emission limits which are not capable of accurate measurement are not achievable. Further, Section 112(h) states that when it is not feasible for the Administrator to prescribe or *enforce an emission standard* for control of hazardous air pollutants, the Administrator may, in lieu thereof, promulgate a design, equipment, work practice or operational standard, which is consistent with Section 112(d). We concur with EPA's updated finding on page 80614 that for all categories of units, emissions were below the value that can be accurately measured. Method 23 is not capable of measuring these HAPs at the levels for various types of combustion units regulated under boiler MACT, and therefore the limits in the Final MACT rule were unenforceable. In addition, under Section 112(h)(2)(b) of the CAA, EPA has the authority to establish work practice standards when "the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations." EPA originally found that dioxin/furan emissions can be precisely measured for at least some units in each subcategory except for Gas 1, therefore "Section 112(h)(2) did not apply because "measurement of emissions is impracticable due to technological and economic limitations." 76 Fed. Reg. 15,640. NEDA/CAP submits that EPA must directly address and correct its prior legal interpretation when the Agency finalizes the proposed rule.

Response: The EPA thanks the commenter for their support.

Commenter Name: Randall D. Quintrell

Commenter Affiliation: Georgia Paper & Forest Products Association

Document Control Number: EPA-HQ-OAR-2002-0058-3451-A1

Comment Excerpt Number: 15

Comment: The adoption of a work practice standard for dioxin/furans is a necessary and appropriate change, especially given that the data show dioxin/furan levels are at such low levels as to be immeasurable in most instances.

Response: The EPA thanks the commenter for their support.

Commenter Name: Bruce W. Ramme

Commenter Affiliation: Wisconsin Electric Power Company (WE Energies)

Document Control Number: EPA-HQ-OAR-2002-0058-3452-A1

Comment Excerpt Number: 1

Comment: Wisconsin Electric Power Company (We Energies) supports EPA's proposed work practice standard for dioxins/furans. It represents a cost-effective approach to regulating dioxin/furan emissions from industrial boilers in lieu of requiring the installation and operation of emission control technology to meet numerical emission limitations that are impractical to measure and create additional recordkeeping and reporting requirements.

Response: The EPA thanks the commenter for their support.

Commenter Name: Michael D. Wendorf

Commenter Affiliation: FMC Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3453-A1

Comment Excerpt Number: 4

Comment: FMC Corp.concurs with EPA's reassessment of the dioxin/furan emission limit and its decision to apply a work practice standard in lieu of a numeric limit. An annual tune-up ensuring good combustion is a reasonable approach to address dioxin/furan emissions, given that the emission limits in the final rule approach method detection level capabilities and with the lack of available emission controls that demonstrate reduction at low dioxin levels.

Response: The EPA thanks the commenter for their support.

Commenter Name: Barry Christensen

Commenter Affiliation: Occidental Chemical Corporation (OCC)

Document Control Number: EPA-HQ-OAR-2002-0058-3477-A1

Comment Excerpt Number: 2

Comment: OCC strongly supports replacing numeric dioxin emissions limits with work practice standards. The data in the record demonstrates that emissions of dioxin from natural gas-fired sources *are below levels that can be accurately quantified*.

Consequently, there is no rational basis for imposing any sort of numerical limit – a limit that cannot be measured or verified.

Response: The EPA thanks the commenter for their support.

Commenter Name: Gary Melow, Director

Commenter Affiliation: Michigan Biomass (MB)

Document Control Number: EPA-HQ-OAR-2002-0058-3478-A1

Comment Excerpt Number: 1

Comment: We strongly support work practice standard for dioxin/furans instead of a numerical emission limit. We were quite concerned about the expense and reliable quantification of our very low emissions with the available test methods. The proposed change resolves this concern.

Response: The EPA thanks the commenter for their support.

Commenter Name: Eric Guelker, Alliant Energy Corporate Services, Inc.

Commenter Affiliation: Interstate Power and Light Company (IPL) and Wisconsin Power and Light Company (WPL), Alliant Energy Corp.

Document Control Number: EPA-HQ-OAR-2002-0058-3492-A1

Comment Excerpt Number: 1

Comment: Alliant Energy supports the use of work practice standards for dioxin/furan emissions.

Response: The EPA thanks the commenter for their support.

Commenter Name: Dirk J. Krouskop

Commenter Affiliation: MeadWestvaco Corporation (MWV)

Document Control Number: EPA-HQ-OAR-2002-0058-3493-A1

Comment Excerpt Number: 9

Comment: MWV believes that work practice standards are appropriate for dioxin/furan. The low levels of emissions of these compounds, difficulty in measurement and lack of proven control technologies all point to the conclusion that EPA has made to require compliance with these requirements to be determined through work practice standards.

Response: The EPA thanks the commenter for their support.

Commenter Name: Timothy Serie

Commenter Affiliation: American Coatings Association (ACA)

Document Control Number: EPA-HQ-OAR-2002-0058-3502-A1

Comment Excerpt Number: 2

Comment: ACA generally supports the following proposed changes in the Boiler MACT rule:

Revision that dioxin/furan emissions will now be regulated using a work practice standard in lieu of numeric emission limits

Response: The EPA thanks the commenter for their support.

Commenter Name: James Johnson

Commenter Affiliation: United States Beet Sugar Association (USBSA)

Document Control Number: EPA-HQ-OAR-2002-0058-3508-A1

Comment Excerpt Number: 8

Comment: In the case of dioxins and furans, work practices are appropriate because of difficulties in assessing compliance with a numerical limit. In the reconsideration of the major source Boiler Rule, EPA acknowledged that a “large majority of all emissions measurements for all the subcategories are below the level that can be accurately measured using EPA method 23.” Therefore, work practices are appropriate in place of numeric limits for dioxins and furans, and USBSA is supportive of EPA’s adoption of work practices for these pollutants.

Response: The EPA thanks the commenter for their support.

Commenter Name: Lorraine Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1
Comment Excerpt Number: 10

Comment: ACC continues to strongly support a work practice approach for dioxin/furan emissions from industrial boilers, as these emissions cannot be reliably measured and there is no technically feasible means of ensuring continuous control of these emissions and EPA has stated that current exposures to dioxins do not pose a health risk,

Response: The EPA thanks the commenter for their support.

Commenter Name: Alicia Meads
Commenter Affiliation: National Association of Manufacturers (NAM)
Document Control Number: EPA-HQ-OAR-2002-0058-3515-A1
Comment Excerpt Number: 5

Comment: The EPA is correct that work practices are appropriate for dioxin/furan, as the large majority of the dioxin/furan measurements are below the level that can be accurately measured. 76 Fed. Reg. at 80,606. This is consistent with the approach that the EPA correctly took in the recently finalized Mercury and Air Toxics Standard.

Response: The EPA thanks the commenter for their support.

Commenter Name: Paul Noe
Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.
Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1
Comment Excerpt Number: 38

Comment: Work practice standards for dioxin/furan, which we support, are workable, while previously considered and rejected performance testing requirements would not be. We also support workable dioxin/furan work practice standards.

Response: The EPA thanks the commenter for their support.

Commenter Name: Allison Watkins, Baker Botts
Commenter Affiliation: Class of '85 Regulatory Response Group

Document Control Number: EPA-HQ-OAR-2002-0058-3608-A1

Comment Excerpt Number: 3

Comment: The Class of '85 supports the use of work practice standards for dioxin/furan emissions. The Group agrees with EPA that emissions of dioxin/furan cannot practicably be measured, making it appropriate for EPA to adopt a work practice standard.

Response: The EPA thanks the commenter for their support.

Commenter Name: Randal G. Oswald

Commenter Affiliation: Integrys Energy Group

Document Control Number: EPA-HQ-OAR-2002-0058-3659-A2

Comment Excerpt Number: 3

Comment: Integrys supports the use of work practice standards for dioxin/furan emissions. We agree with EPA that emissions of dioxin/furan cannot practicably be measured, making it appropriate for EPA to adopt a work practice standard.

Response: The EPA thanks the commenter for their support.

Commenter Name: Annabeth Reitter

Commenter Affiliation: NewPage Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3662-A2

Comment Excerpt Number: 1

Comment: NewPage Corporation supports the replacement of numerical dioxin/furan numerical standards with work practice standards.

Response: The EPA thanks the commenter for their support.

Commenter Name: Vickie Woods

Commenter Affiliation: Division of Air Quality, North Carolina Department of Environment and Natural Resources (NCDENR)

Document Control Number: EPA-HQ-OAR-2002-0058-3663-A2

Comment Excerpt Number: 4

Comment: NC DAQ supports the change to apply work practice standards for dioxins in lieu of numeric emission limits and emission tests, as NC DAQ requested EPA consider such a change. NC DAQ agrees with the proposed work practice standards to require annual tune-up to ensure good combustion practice, since the majority of dioxin emission data (55%) for this category was below detection.

Response: The EPA thanks the commenter for their support.

Commenter Name: Stuart A. Clark

Commenter Affiliation: State of Washington Department of Ecology

Document Control Number: EPA-HQ-OAR-2002-0058-3665-A2

Comment Excerpt Number: 2

Comment: We support EPA's decision to not establish numerical emission limits for dioxin/furan emissions from major source biomass boilers, since all emissions reports are at or below the detection limit for the test method. We also support EPA's recognition that good combustion practices and boiler design are a reasonable way to control for particulate matter, carbon monoxide, and dioxin.

Response: The EPA thanks the commenter for their support.

Commenter Name: Steve Gossett

Commenter Affiliation: Eastman Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3669-A2

Comment Excerpt Number: 3

Comment: Comment Summary: We fully support EPA's proposal to set work practice standards for dioxins/furans in lieu of numeric emission limits.

Discussion: We agree that levels of dioxins measured in stack gas from industrial boilers are below the levels that can be accurately measured. Additionally, we are unaware of emission controls that are demonstrated to reduce dioxins from these low levels.

Response: The EPA thanks the commenter for their support.

Commenter Name: Pat Dennis

Commenter Affiliation: Archer Daniels Midland Company

Document Control Number: EPA-HQ-OAR-2002-0058-3670-A2

Comment Excerpt Number: 1

Comment: ADM supports the EPA's decision to apply work practice standards for dioxins/furans emissions instead of applying numeric emission limits. EPA has "re-assessed the dioxin/furan data sets and has determined that, similar to data for electric utilities for which work practice standards were proposed for dioxins/furans, the large majority of the emission measurements for all of the subcategories are below the level that can be accurately measured using EPA Method 23 ... [T]he EPA concludes that emissions from industrial boilers and process heaters cannot practicably be measured, and the EPA is now proposing work practice standards in place of numeric emission limits for dioxin/furan." 76 Fed. Reg. 80,606 (2012 Reconsideration Rule). ADM supports this proposal.

Response: The EPA thanks the commenter for their support.

Commenter Name: Bill Lane

Commenter Affiliation: American Home Furnishings Alliance (AHFA)

Document Control Number: EPA-HQ-OAR-2002-0058-3676-A2

Comment Excerpt Number: 6

Comment: AHFA supports EPA's proposal to establish work practice standards. In particular, AHFA agrees that work practice standards are appropriate in place of numeric standards for dioxin/furan emissions. AHFA agrees with EPA's conclusion that dioxin/furan emissions from boilers "cannot practicably be measured." (76 Fed. Reg. at 80606). Thus, work practice standards can be applied pursuant to CAA Section 112(h).

Response: The EPA thanks the commenter for their support.

Commenter Name: Heather Parent

Commenter Affiliation: Maine Department of Environmental Protection

Document Control Number: EPA-HQ-OAR-2002-0058-3691-A2

Comment Excerpt Number: 5

Comment: Maine DEP supports the replacement of dioxin/furan emission standards with work practice standards. Maine DEP does not believe that dioxin/furan testing would be an effective regulatory approach to reduce dioxin/furan emissions from these units.

Response: The EPA thanks the commenter for their support.

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 29

Comment: EPA now proposes to set work practice standards instead of emission standards for dioxins. 76 Fed. Reg. at 80,614. The agency claims that "for all subcategories of units, emissions were below the value that can be accurately measured." *Id.* at 80,614, 80,606. EPA claims that about 55% of its test runs are below the MDLs and that a high percentage are below a level "that can be accurately measured" under EPA Method 23. *Id.* at 80,606. By "a level that can be accurately measured," EPA appears to mean a level three times higher than the RDL ("3 x RDL"). *See* EPA, Analysis of Dioxin/Furan Data and Minimum Detection Levels from Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants – Major Source (November 2011) at 11. The agency concludes that it is, therefore, not "practicable" to measure dioxins from boilers. *Id.*

In claiming that it can set work practice standards in lieu of emission standards for boilers' dioxin emissions, EPA misreads § 112(h) as a license to set work practice standards whenever a number of emission tests falls below MDLs or 3 x RDL. That is not what § 112(h) says. Section 112(h) allows EPA to issue work practice standards in lieu of emission standards only where it is not feasible to prescribe or enforce an emission standard. 42 U.S.C. § 7412(h)(1). Further, it provides expressly that the term "not feasible to prescribe or enforce an emission standard" refers only to situations where: "(A) a hazardous air pollutant cannot be emitted through a conveyance designed and constructed to emit or capture such a pollutant, or that any requirement for, or use of, such a conveyance would be inconsistent with any Federal, State, or local law, or (B) the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations." 42 U.S.C. § 7412(h)(2). EPA's claims that some boilers' dioxin emissions fall below the MDL these sources chose to employ does not speak to

this standard far less satisfy it. Neither does EPA's claim that a high percentage of boilers' dioxin emissions fall are below 3 x RDL. Those claims merely purport to show that some sources emissions are lower than the detection limits for some measurement methods, not that "measurement methodology" for boilers dioxin emissions is not practicable.

Response: The EPA disagrees with the commenter that it misreads §112(h). Section 112(h) clearly allows the Administrator to set a work practice standard instead of an emission limit if it is not feasible to prescribe or enforce an emission standard. As stated in the reconsideration proposal, the EPA assessed the dioxin/furan data sets and determined that the large majority of the emission measurements for all of the subcategories are below the level that can be accurately measured using EPA Method 23. As the commenter indicated, the percentages of measurements (test runs) below the method detection level (a level at which the pollutant is known to be present but is not accurately quantified) is about 55 percent. In addition to the high percentage of measurements below the method detection level, a very high percentage (85 to 100 percent) of measurements are below the level that can be accurately measured (i.e., 3 x RDL) for each subcategory. Based on the percentages of data below the method detection limit coupled with the percentage of data below the level that can be accurately quantified, the EPA concluded that emissions from industrial boilers and process heaters cannot practicably be measured, and, thus, it would be inappropriate (not feasible) to establish (prescribe) a numeric emission limits for dioxin/furan because it is unreasonable to required a source to demonstrate compliance with a questionably inaccurate emission limit based on questionable performance test results. The work practice standards require an annual tune-up to ensure good combustion. In addition, we are not aware of any emissions controls that are demonstrated to reduce dioxin emissions from the low levels indicated by the available data for boilers and process heaters.

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 30

Comment: EPA offers no reason to believe that emission standards could not be set at a specific detection level. Certainly, EPA would not and could not dispute than it can set an emission standard at zero even though emissions below zero cannot be detected; the Clean Air Act expressly authorizes the agency to issue a "prohibition" on emissions where achievable. 42 U.S.C. § 7412d)(2). *A fortiori*, the agency can issue standards at a specific detection limit higher than zero even if emissions cannot be measured below that detection limit. That emissions below a certain level cannot be measured is always true, but this truism does not show that measurement of emissions is not practicable.

Further, EPA's claims that some test runs fall below sources' self-chosen detection limits does not establish that measurement is not practicable under § 112(h). As noted above, EPA refused to specify a test method for dioxin emissions and thereby effectively encouraged sources to use the cheapest and least accurate tests and to submit data that lacked precision and incorporated high MDLs. The agency cannot use its own choice to collect imprecise data as an excuse to avoid setting emission standards. That EPA chose not to collect better data does not show that measurement of dioxin emissions is not practicable. Rather, assuming *arguendo* that EPA lacks

data that are sufficiently precise to allow the agency to set emission standards, that fact would merely show that EPA chose not to collect adequate data.

Response: We disagree with the commenter that the EPA refused to specify a test method for dioxin emissions which encourage sources to conduct test that lack precision and incorporates high MDLs. In the tests conducted as part of the ICR for dioxin emissions, we required that EPA Method 23 be used and that the source collect a minimum volume of 2.5 cubic meters or have a minimum sample time of 4 hours per run that would result in low method detection levels (MDLs) in order to increase the possibility of collecting measurable amounts of dioxins and minimize the number of non-detects .

The EPA believes that the work practices being finalized for dioxins are appropriate and are consistent with the statute and other NESHAP rulemaking efforts. Further, each source category is addressed individually and, although EPA strives for consistency in its approach, there are times where different approaches for different source categories are warranted. The EPA does not believe that, at this time, it can specify a maximum MDL for dioxin emissions from boilers and process heaters covered by the Boiler MACT as that would require specifying laboratory analysis methods which, at this time, are not universally available in the U.S. (e.g., only one or two laboratories are equipped for high-resolution mass spectroscopy analyses.

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 31

Comment: EPA still could set an emission limit at the detection level if it believes that the relevant best sources are emitting dioxins at or below that level. Assuming that it is lawful and non-arbitrary to adjust test results below the detection level upward – as EPA has done for other pollutants – the agency would be able to set an emission standard somewhat above the detection level if it believes that the relevant best sources are emitting dioxin emissions below the detection level. And even if the agency could not for some reason set standards based on the sources achieving emissions below the detection level, the agency admits that a substantial portion of the data it has (45%) are above detection levels. Thus, EPA could base standards on these emissions and specify a test method that would detect emissions at these levels.

Response: As indicated in the response to comment EPA-HQ-OAR-2002-0058-3511-A1, excerpt 14, we believe that using a measurement value of 3 times a method's detection limit established in a manner that assures 99% confidence of a measurement above zero will produce a representative method reporting limit (MDL) suitable for establishing regulatory floor values. In the case of dioxin emissions from boilers and process heaters, 98 percent of measurements are below the level (i.e., 3 x RDL) that can be accurately measured, even under the increased sampling times required in the ICR testing program. See the response to comment EPA-HQ-OAR-2002-0058-3511-A1, excerpt 30. We continue to conclude that dioxin emissions from industrial boilers and process heaters cannot practicably be measured and the EPA is finalizing work practice standards that require an annual tune-up to ensue good combustion.

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 32

Comment: Nor is it relevant that many measurements fall below EPA's arbitrarily chosen "3x RDL." The 3x RDL is a product of two arbitrary decisions: (1) to look to the mean detection limit for all the best performers in any category, rather than determine a level below which dioxin truly cannot be detected; (2) to multiply that "RDL" by 3, without showing that three times that level reflects the an emission level below which dioxin cannot be detected. Obviously many of the tests were below 3x RDL; that is why the percentage of sources with levels below their self- chosen MDLs is 55% percent while the percentages of runs with emissions below the 3s RDL are higher. Because even many of the MDLs that sources self-selected can detect dioxin levels below 3x RDL, the mere fact that many test runs are below the detection level for EPA Method 23 scarcely shows that measuring boilers' dioxin emissions is impracticable.

Response: For each pollutant and associated test method, we established a pollutant concentration value that would be characteristic of the method detection limit achieved during collection of the data used in the floor calculations. The RMDL (Representative Method Detection Limit aka RDL) is not the lowest method detection limit reported but is a value typical of the method detection limits specific to the method used and the typical stack matrix. The RDL values used to support this rule are derived from the reported data used in setting the floor, from research studies of the test methods used in stack matrices similar to those encountered for a subject source category, or from calculations based on the method's required quality assurance and quality control requirements.

In the end, the RDL is a pollutant and method specific predictor of method detection limit capability in an application typical of that source category. The purpose of calculating a RMDL is to define a pollutant concentration value that accounts for at least some of the typical measurement variability at the method detection limit not otherwise addressed in the database used in the floor calculations. We believe that the outcome should minimize the effect of a test(s) with an inordinately high method detection level (*e.g.*, the sample volume was too small, the laboratory technique was insufficiently sensitive, or the procedure for determining the minimum value for reporting was other than the detection level). We then call the resulting mean of the method detection levels the representative detection level (RMDL) because it is characteristic of accepted source emissions measurement performance. To identify the RDL, the EPA first identifies the "method detection level" (MDL), which is the smallest quantity of a pollutant that can be measured. The MDL will vary among testing contractors for any number of reasons (*e.g.*, different testing equipment, sampling volumes, etc.). The EPA averages the MDLs from all tests from the best performing units in order to determine the level at which a competent testing contractor can measure emissions (the RDL). The RDL thus accounts for intra- and inter-laboratory variability since, by definition, it is the average of the capabilities of all contractors and their laboratories.

MDL (Method Detection Limit) is a value specific to each tester and laboratory combination. This number may be lower or higher than the calculated RMDL, but we expect it to be reasonably equivalent as these data were used in determining the RMDL. 3x RMDL is a value

used in MACT floor determination, in comparison to the 99% UPL calculated emission rate. It is not used as a detection limit decision point, as suggested by the commenter. 55% and greater of the sources reporting emissions had non detect values below the MDL which is much lower and, as stated above, we expect to be in the realm of the RMDL value. In this manner therefore, greater than 98% of sources will have emissions that were below the 3x RMDL value. Therefore, we continue to conclude that dioxin emissions from industrial boilers and process heaters cannot practicably be measured and the EPA is finalizing work practice standards that require an annual tune-up to ensue good combustion.

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 33

Comment: EPA also chooses to ignore other dioxin measurement methods are available. Dioxin continuous emission monitors are available and EPA could use these to measure emissions. Further, it is well established that dioxins can be measured down to levels measured in femtograms per cubic meter. [See submittal p.22 for California Ambient Dioxin Air Monitoring Program (October, 2004).]

Response: The EPA recognizes the existence of other dioxin measurement methods and yet also recognizes the importance of consistency in measurements of these low magnitudes as well as the necessity of using the measurement technique for compliance determinations that was used to establish the emissions limit. At this time the EPA holds that method 23 is the appropriate tool for dioxin and furan emissions determinations. We disagree that dioxin continuous emission monitors are available. There is currently no performance specification (PS) for continuous chlorinated dibenzo(p)dioxin (dioxins) or chlorinated dibenzofuran (furans) monitoring. None of the approaches evaluated during the Environmental Technology Verification Program for Dioxin Emission Monitoring Systems met our nominal performance criteria requirement of 20 percent relative accuracy. While EPA believes there is potential to improve one or more of the continuous monitoring approaches for dioxins and furans to meet our performance requirements, we would need to further evaluate monitoring system performance and promulgate a performance specification before we would consider requiring continuous monitoring for dioxins/furans on a broad basis.

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 34

Comment: EPA chooses to ignore that truth that dioxin can be measured – with the EPA Method 23 or with other methods – simply by extending the testing time. As EPA itself recognizes, the longer the testing time, the larger the dioxin sample. Thus dioxin emission levels that could not be measured in a one hour test can be measured in a two hour or five hour test. EPA, Analysis of Dioxin/Furan Data and Minimum Detection Levels from Industrial,

Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants – Major Source (November 2011) at 3-2 % Table 2-1.

Response: The EPA has proposed rules that include extended sampling times for EPA method 23 dioxin and furan measurements, and the guidance document we have recently issued to rule writers (“Data and procedure for handling below detection level data in analyzing various pollutant emissions databases for MACT and RTR emissions limits”), speaks to this directly.

As stated in the response to comment EPA-HQ-OAR-2002-0058-3511-A1, excerpt 30, in the tests conducted as part of the ICR for dioxin emissions, we required that EPA Method 23 be used and that the source collect a minimum volume of 2.5 cubic meters or have a minimum sample time of 4 hours per run in order to increase the possibility of collecting measurable amounts of dioxins and minimize the number of non-detects . Even at these extended sampling times, 98 percent of the measured dioxins were below the level that can be accurately measured (3 x RDL).

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 35

Comment: EPA ignores that continuous emission monitors for dioxins are available, and could be used these to measure emissions rather than a periodic stack testing method. [See p. 61 of submittal for EPA, Environmental Technology Verification Program, Dioxin Emission Monitoring Systems.]

Response: There is currently no performance specification (PS) for continuous chlorinated dibenzo(p)dioxin (dioxins) or chlorinated dibenzofuran (furans) monitoring. None of the approaches evaluated during the Environmental Technology Verification Program for Dioxin Emission Monitoring Systems met our nominal performance criteria requirement of 20 percent relative accuracy. (See <http://www.epa.gov/etv/pubs/600s07002.pdf>)

While EPA believes there is potential to improve one or more of the continuous monitoring approaches for dioxins and furans to meet our performance requirements, we would need to further evaluate monitoring system performance and promulgate a performance specification before we would consider requiring continuous monitoring for dioxins/furans on a broad basis.

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 36

Comment: Ultimately, EPA’s claims simply ignore the reality that dioxin emissions can be measured and are being measured. Although EPA may be willing to pretend that dioxins cannot be measured in an effort to avoid setting a dioxin standard, the agency’s willingness to dissimulate in pursuit of that policy and political goal does not alter the reality that measuring

dioxin emissions is feasible. For all the reasons above, EPA's proposal to set work practice standards instead of emission standards for dioxins is unlawful and arbitrary.

Response: See the responses to comment EPA-HQ-OAR-2002-0058-3511-A1, excerpts 30, 33, and 35.

Commenter Name: Janice E. Nolen

Commenter Affiliation: American Lung Association

Document Control Number: EPA-HQ-OAR-2002-0058-3679-A2

Comment Excerpt Number: 11

Comment: The removal of emissions limits for dioxins and furans is especially troubling. Contrary to EPA's claim dioxin emissions can be measured and are being measured. But even if dioxins could not be accurately measured using the required test measurement, the EPA should set design or equipment requirements to accomplish the task, as is authorized in the same list as work practice standards in Section 112(h). The EPA should not simply default to "an annual tune up" (EPA, 2011d).

We support steps to improve work practices to ensure emissions do not increase. However, that is not enough. Work practice standards do not reflect measures that yield the maximum achievable degree of reduction in these pollutants nor, at a minimum, reflect the measures adopted by facilities with the lowest emission levels. If EPA were to set work practice standards, it would have to require the use of these technologies at a minimum. Moreover, the proposed rule provides no means to enforce compliance with even these limited requirements.

Response: See the responses to comment EPA-HQ-OAR-2002-0058-3511-A1, excerpts 29 through 36.

Commenter Name: Lorna Fear

Commenter Affiliation: Visual Cue Thermal Imaging

Document Control Number: EPA-HQ-OAR-2002-0058-3770-A1

Comment Excerpt Number: 2

Comment: I am also concerned that replacing numeric dioxin limits with work practice standards could take us in the wrong direction.

Response: The EPA acknowledges this comment.

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 37

Comment: EPA listed boilers under Clean Air Act § 112(c)(6) because, under this provision, it must assure that sources accounting for ninety percent of the emissions of dioxins and POM are subject to emission standards under § 112(d)(2) or (d)(4). As the agency has acknowledged, it

cannot meet this ninety percent requirement without assuring that boilers are subject to such standards.

For boilers to be subject to standards under § 112(d)(2), EPA must set § 112(d)(2) standards for each hazardous air pollutant that boilers emit, including dioxins and POM. EPA may not regulate sources that it lists under § 112(c)(6) under § 112(h), nor may it issue § 112(h) standards for any pollutant that sources listed under § 112(c)(6) emit. For this reason alone, EPA's proposal to set § 112(h) work practice standards instead of § 112(d)(2) emission standards for boilers emissions of dioxins and POM is flatly unlawful.

EPA has argued that § 112(c)(6) does not require it to set § 112(d)(2) standards for all of the hazardous air pollutants emitted by the sources it lists under § 112(c)(6) but, rather, only the specific pollutants enumerated in § 112(c)(6). Even under the agency's interpretation of § 112(c)(6), therefore, it must set § 112(d)(2) standards for boilers' emissions of dioxins and POM, both of which are expressly enumerated in § 112(c)(6). Section 112(c)(6) does not say that EPA may set standards for such sources (or pollutants) under § 112(h), but rather specifies that the agency must set standards under § 112(d)(2) or (d)(4). EPA's proposal to set work practice standards for dioxins and POM contravenes that requirement.

Response: The commenter's argument is based on section 112(c)(6)'s provision that EPA establish standards pursuant to section 112(d)(2) or (d)(4). However, the commenter ignores the fact that section 112(h)'s authority to establish work practice standards applies "for purposes of this section," i.e., all of section 112. Therefore, EPA has authority to establish work practice standards in lieu of numeric emissions standards for any standard it establishes under any provision of section 112, not just standards for sources that are not needed to meet the Agency's section 112(c)(6) obligation. Had Congress intended that EPA must issue numeric emissions limits to meet that obligation, it could have specified so in section 112(c)(6), or could just as easily have limited EPA's work practice authority under section 112(h) to certain subsections of section 112. However, it chose not to do so.

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 38

Comment: EPA's failure to explain how its decision to set work practice standards instead of emission standards for boilers' emissions of dioxins and POM can be squared with Clean Air Act § 112(c)(6) or even its own interpretation of § 112(c)(6) is arbitrary and capricious.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3511-A1, excerpt 37.

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 39

Comment: The Clean Air Act required EPA to complete its obligations under § 112(c)(6) no later than November 15, 2000, and the agency is subject to a court order requiring it to complete these long overdue standards by February, 2011. By failing to set emission standards under § 112(d)(2) or (d)(4) for boilers' emissions of dioxins and POM, EPA would not only violate the Clean Air Act but the court's order.

Response: EPA disagrees with the commenter's interpretation of the Clean Air Act, and of the Agency's obligation under the District Court order. First, the order required EPA to meet its obligations under section 112(c)(6) by February 21, 2011. EPA's issuance of the major source boilers rule was part of its actions to meet this obligation. Therefore, the court order required EPA to do only what the Agency is required to do under section 112(c)(6), and to have done so by a certain date.

Commenter Name: Janice E. Nolen

Commenter Affiliation: American Lung Association

Document Control Number: EPA-HQ-OAR-2002-0058-3679-A2

Comment Excerpt Number: 9

Comment: Work practice standards. The American Lung Association is troubled by the EPA's continued reliance on work practice standards, particularly as they would be the sole means of reducing toxic emissions for 13 percent of boilers and heaters and for dioxins and furans. Although Section 112(h) of the Clean Air Act permits EPA to establish work practice standards as an option for reducing emissions, the Act intentionally limits their use, with explicit instructions that these are to be used only if it is infeasible to prescribe or enforce emission standards and further requires that any work practice standards be consistent with actual emission standards that EPA would set under § 112(d) if it were feasible to do so. Here, EPA has not shown and cannot show that it is infeasible to set emission standards for boilers, and the work practice standards it issued are not consistent with § 112(d). Rather, EPA has merely used work practice standards as an excuse to rationalize allowing industry to keep doing the same thing they currently do as being consistent with setting emissions standards on 195,000 boilers.

Response: See the response to comment EPA-HQ-OAR-2002-0058-A1, excerpt 37.

Commenter Name: Mary Sullivan Douglas

Commenter Affiliation: National Association of Clean Air Agencies (NACAA)

Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1

Comment Excerpt Number: 30

Comment: EPA now proposes to adopt a similar "work practice" standard for dioxin and furan emissions, again asserting that enforcing a numerical limit is impracticable, notwithstanding the hundreds of D/F emission tests in the rulemaking record. EPA argues that this is demonstrated by the large number of results that are "non-detect" ("ND"), detection level limited ("DLL") or BDL. First, we note that this problem is of EPA's creation. EPA knew, before testing was to be conducted, that many results would be at or below detection limits if it only required sample periods of one hour per run. Indeed, industry sources specifically raised this issue and inquired whether they should extend sample periods to ensure more precise results. EPA's response was that sources need not do so and that EPA would "address" the issue in its rulemaking. Testing for

D/F and other pollutants often included detection and quantification limits that are quite high – one source reported a detection limit for mercury that equates to 6.57 lb of mercury emissions per year,³¹ while several sources reported D/F detection limits several orders of magnitude larger than the levels of regulatory interest. Further, if the standard is set at the most common detection limit, plus an appropriate variability factor, no harm is done, since a subsequent emission test that is BDL would not constitute a violation. Retaining such a limit would not require any change in performance for relatively clean units, but would at least require gross emitters to reduce emissions.

[Footnote]

(31) This is roughly equivalent to a quantification limit of more than 60 lb/yr. EPA refers to the quantification limit as the level at which emissions can be measured accurately.

Response: This comment speaks to justification for the work practice standards. See the response to comment EPA-HQ-OAR-2002-0058-3511-A1, excerpt 30

We disagree with the commenter assertion that EPA, knowing many results would be at or below detection limits if it only required sample periods of one hour per run, responded to industry that the sources need not extend sample periods to ensure more precise results. In fact, enclosure 1 to the ICR letter requesting testing stated the methods and sampling times or volumes. For example, for sampling for metals, it was stated EPA Method 29 be used and to collect a minimum volume of 4.0 cubic meters or have a minimum sample time of 4 hours per run. For dioxins/furans, enclosure 1 specified that EPA Method 23 be used and to collect a minimum volume of 2.5 cubic meters or have a minimum sample time of 4 hours per run.

Commenter Name: Mary Sullivan Douglas

Commenter Affiliation: National Association of Clean Air Agencies (NACAA)

Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1

Comment Excerpt Number: 31

Comment: Developing a meaningful work-practice standard for controlling D/F emissions is far more difficult and resource intensive than merely reducing CO levels. According to the Industrial Combustion Coordinated Rulemaking (“ICCR”) study³², control of CO levels is not sufficient; one must also examine the interaction of several factors in a complex combustion environment. The ICCR study concludes that CO monitoring can help confirm that current operating conditions are the same as during a D/F emissions test, but are not a direct indicator of low D/F emissions; equivalent dioxin levels can be found at 1 ppm as are found at 4,000 ppm CO levels. Other factors were found to be more important and, based on the ICCR workgroup results, meaningful work-practice standards would have to include good combustion practices (including total hydrocarbon and CO concentrations, soot formation and particle entrainment), quench rate, air pollution control device temperature and fuel and waste parameters.³³ Large ICI boilers will have far higher flow rates than medical waste incinerators and so may actually emit a substantial amount of dioxin on an hourly (or certainly annual) basis. As discussed above, such a task would require significant resources. Indeed, such an effort would likely be more expensive than testing. There is no reason to suspect that manufacturers would voluntarily do so (even if it could be done) and no authority to require that they invest in such an effort.³⁴

Some manufacturers may, as a courtesy to their clients, publish “nominal” good combustion practices. However, there is no way for federal, state or local enforcement authorities to require that such practices have any practical impact. The end result would be additional paperwork demands on sources and permitting authorities and no environmental benefit.

[Footnotes]

(32) See, Gullet, B., USEPA, and Seeker, Randy, EER Corp “*Chlorinated Dioxin and Furan Formation, Control and Monitoring*” 1997.

(33) See, Gullet, B., USEPA, and Seeker, Randy, EER Corp “*Chlorinated Dioxin and Furan Formation, Control and Monitoring*” 1997, slide 79.

(34) It is also likely that the manufacturers of a large number of boilers are no longer in business.

Response: The work practice standards require an annual tune-up to ensure good combustion. In addition, we are not aware of any emissions controls that are demonstrated to reduce dioxin emissions from the low levels indicated by the available data for boilers and process heaters.

The ICCR study was part of the original Boiler MACT rulemaking promulgated in 2004. In the September 13, 2004 preamble, we acknowledge that there are many factors that affect the formation of dioxin, and that dioxin can be formed in both the combustion unit and downstream in the associated PM control device. At that time, we indicated that minimizing organic HAP emissions can limit the formation of dioxin in the combustion unit. We reviewed all the good combustion practice (GCP) information available in the boiler population database and determined that no control existed, except for limiting CO emissions. One control technique, controlling inlet temperature to the PM control device, that has demonstrated controlling downstream formation of dioxins in other source categories (*e.g.*, municipal waste combustors) was analyzed for industrial boilers. In all cases, no increase in dioxins emissions were indicated across the PM control device even at high inlet temperatures.

Commenter Name: Mary Sullivan Douglas

Commenter Affiliation: National Association of Clean Air Agencies (NACAA)

Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1

Comment Excerpt Number: 32

Comment: EPA’s real argument appears to be that setting D/F limits for these sources is “not worth it” because emission levels are “small.” If this is the case, EPA should make this argument clearly and support it with objective facts. It should, at least, compare daily/annual D/F emissions from medical waste incinerators (and other source categories) with D/F limits with anticipated D/F emissions from high emitters to see if those emissions are *de minimis*. Additionally, EPA should explore options to reduce testing burdens for the sector. Potential areas for reduced testing costs are pooled testing for units of similar designs and reduced testing frequencies for sources whose emissions are below a certain threshold. Additionally EPA could

attempt to review operating conditions for better performing units to determine whether there are readily discernible operating conditions (such as maximum boiler temperature, oxygen levels or chlorine content of fuel and designed residence time) where parametric monitoring can be employed in lieu of reference testing. EPA might also consider a threshold where, if sources demonstrate very low D/F emission rates, a one-time test, combined with parametric monitoring might suffice.

Response: As stated in the reconsideration proposal, the EPA assessed the dioxin/furan data sets and determined that the large majority of the emission measurements for all of the subcategories are below the level that can be accurately measured using EPA Method 23. As the commenter indicated, the percentages of measurements (test runs) below the method detection level (a level at which the pollutant is known to be present but is not accurately quantified) is about 55 percent. In addition to the high percentage of measurements below the method detection level, a very high percentage (85 to 100 percent) of measurements are below the level that can be accurately measured for each subcategory. Based on the percentages of data below the method detection limit coupled with the percentage of data below the level that can be accurately quantified, the EPA concluded that emissions from industrial boilers and process heaters cannot practicably be measured, and, thus, it would be inappropriate (not feasible) to establish (prescribe) a numeric emission limits for dioxin/furan because it is unreasonable to required a source to demonstrate compliance with a questionably inaccurate emission limit based on questionable performance test results. The work practice standards require an annual tune-up to ensure good combustion. In addition, we are not aware of any emissions controls that are demonstrated to reduce dioxin emissions from the low levels indicated by the available data for boilers and process heaters.

Commenter Name: Roger Martella

Commenter Affiliation: National Alliance of Forest Owners (NAFO)

Document Control Number: EPA-HQ-OAR-2002-0058-3519-A1

Comment Excerpt Number: 6

Comment: In its Major Source rule comments, NAFO urged EPA to adopt work practice standards for dioxin/furan,²⁶

For the same reasons, EPA should adopt work practice standards in lieu of emissions limits for mercury emissions from biomass boilers. As explained in our Major Source rule comments, EPA's proposed mercury emissions limits were also below detection limits and would require expensive control technology while providing little if any health benefit.²⁷

Thus, and we support EPA's decision to do so now. As EPA recognizes, baseline dioxin/furan emissions from biomass are already extremely low and, in many cases, are below detection limits. As a result, stringent emissions limits, such as those currently in effect, will require the installation of extremely expensive control technology while providing little if any health benefit. Further given the current detection limits, it will be impossible to distinguish between compliant and non-compliant facilities. For these reasons, we support EPA's proposal invoking its authority under section 112(h)(2)(B) of the Clean Air Act to issue work practice standards in lieu of emissions limits for dioxin/furan emissions. EPA should also adopt work practice standards in lieu of emissions limits for mercury emissions from biomass boilers. [Footnote 26: NAFO Major Source Rule Comments, at 7, 9.]

[Footnote 27: NAFO Major Source Rule Comments, at 7, 9.]

Response: The EPA thanks the commenter for their support of the dioxin/furan work practice standard.

The EPA disagrees with the commenter that work practice standards should be established for mercury emissions from biomass boilers. Over two-thirds of mercury emission test runs reported to EPA from the combustion of biomass fuels were reported above a detection limit. Thus, EPA does not agree that there is a significant measurement detection issue for mercury emissions from biomass boilers.

6B. Regulating PM as a Combustion-Based Pollutant

Commenter Name: David A. Buff, Golder Associates Inc.

Commenter Affiliation: Florida Sugar Industry (FSI)

Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1

Comment Excerpt Number: 7

Comment: The FSI agrees with EPA that PM should be treated as a combustion-based pollutant, instead of a fuel-based pollutant. PM emissions are influenced by fuel characteristics (such as heating value, moisture and ash content) and the combustor design, both of which can vary greatly in biomass fired boilers. PM emissions also can be influenced greatly by the type of control devices that can be applied to the boiler. Consequently, it is appropriate for EPA to establish separate subcategories for biomass-fired boilers and to establish separate PM emission limits for each subcategory. As the FSI has noted in its prior comments to EPA, the PM emission limits for the FSI's hybrid suspension grate boilers and cell-type boilers should be based solely on the performance of the boilers in those subcategories.

Response: The EPA thanks the commenter for their support.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 15

Comment: There are not enough differences in levels of uncontrolled PM or TSM from these three types of coal-fired boilers to justify subcategorization. A review of EPA's database on controlled emissions does not reveal significant differences. This is evident from Appendices B and C of the ERG MACT floor memorandum found in the docket. Shown below are comparisons of the average of all test runs for top performers in the three coal subcategories compared to the two abovementioned biomass subcategories. [See submittal for table comparing PM emissions biomass categories.]

Here it can be observed that the two biomass subcategories differ substantially from the coal subcategories and would seem to merit their own subcategories as described in their petitions. However, there are relatively minor differences in the three coal subcategories. The emissions data for coal units do not indicate there is a substantial difference in PM emission rates between

stokers, pulverized coal, and fluidized bed coal boilers. Finally, either electrostatic precipitators (ESPs) or fabric filters can be deployed to effectively control PM/TSM emissions from any of these three boiler types. In conclusion, EPA should combine all coal boilers into one subcategory with one set of PM and alternative TSM emission limits.

Response: The EPA agrees with the commenter that there is not enough differences in levels of uncontrolled PM or TSM from the three types of coal boilers to justify subcategorization for PM or TSM. In the final rule, all coal units (regardless of combustor design) are subject to a single PM standard (or a single TSM alternative). Regulation of PM emissions on a combustor design basis has been retained in the final rule for the various biomass subcategories.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 12

Comment: *There is Not a Strong Technical Basis for Subcategorization of Coal Boilers for PM*

Coal-fired boilers should not be subcategorized by boiler design to set PM or TSM emission limits. EPA added a solid fuel subcategory to the Final Boiler Rule that replaced previously proposed separate subcategories for units designed to burn solid fossil-based fuels and units designed to burn solid bio-based fuels. The solid fuel subcategory applied to pollutants identified in the final rule as fuel-based pollutants (PM, HCl, and Hg). Standards for combustion-based pollutants (carbon monoxide (CO)), however, were based on specific subcategories for the various types and designs of combustion units, including the specific primary fuel types the units were designed to combust.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 15.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 13

Comment: In response to two petitioners' requests for separate subcategories for PM, EPA established a separate PM emission limit for the subcategory —hybrid suspension grate units designed to burn biomass/bio-based solid,|| which is defined by fuel with moisture content of at least 40 percent. However, in responding to these two petitioners, whose arguments appear to be strongly in support of separate subcategories for biomass units, EPA went a step further by setting separate PM standards for both biomass and coal design subcategories. EPA has no basis for applying the arguments presented to subcategorize *biomass* boilers to now subcategorize *coal* boilers.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 15.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 14

Comment: Of particular interest to ACC is the decision by EPA to subcategorize the coal-fired boilers into three groups by boiler type (stokers, pulverized coal, and fluidized bed). We agree that PM/TSM limits should be set separately for coal boilers apart from biomass boilers, but we disagree that coal units should be further subdivided. The results of EPA MACT floor determinations for PM by coal design type are counter-intuitive. The limit for coal fluidized bed boilers is highest and the limit for coal stoker boilers is lowest.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 15.

Commenter Name: Steve Gossett

Commenter Affiliation: Eastman Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3669-A2

Comment Excerpt Number: 11

Comment: Coal-fired boilers should not be subcategorized by boiler design to set particulate matter or total selected metals emission limits.

Two petitioners requested separate subcategories be established for particulate matter emission standards. One requested a subcategory for "nondrying suspension boilers" arguing that they are unique devices burning dry wood fuel that have a unique emissions profile with respect to PM due to combustion in suspension, high excess air, and a high peak combustion temperature. In response, EPA established a new subcategory called "stokers/sloped grate/others designed to burn kiln-dried biomass fuel". A second petitioner requested a subcategory for bagasse-fueled boilers due to the high moisture content and low density causing a less complete burn than occurs with drier, denser fuels, thereby elevating the levels of PM. Also, the petitioner argued that bagasse-fueled boilers emit a high amount of PM relative to their non-mercury metallic HAPs. In response, EPA established a separate PM emission limit for the subcategory "hybrid suspension grate units designed to burn biomass/bio-based solid", which is defined by fuel with moisture content of at least 40 percent. However, in responding to these two petitioners, EPA went a step further by setting separate PM standards for a total of 10 solid fuel subcategories, including these two. EPA has no basis for using this broad-brush approach to further subdivide the other solid fuel boilers.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 15.

Commenter Name: Steve Gossett

Commenter Affiliation: Eastman Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3669-A2

Comment Excerpt Number: 12

Comment: Of particular interest to Eastman is the decision by EPA to subcategorize the coal-fired boilers into three groups by boiler type (stokers, pulverized coal, and fluidized bed). As stated elsewhere in these comments, we agree that PM/TSM limits should be set separately for coal boilers apart from biomass boilers, but we disagree that coal units should be further

subdivided. The results of EPA MACT floor determination are counter-intuitive. First, the limit for fluidized bed is unreasonably high, and the limit for stokers is unexplainably low. Second, PM is supposed to be a surrogate for TSM, yet this analysis shows the two to be inversely related. There are not enough differences in levels of uncontrolled PM or TSM from these three types of coal-fired boilers to justify subcategorization. A review of EPA's database on controlled emissions does not reveal significant differences either. This premise is evident from Appendices B and C of the MACT floor memorandum found in the docket. Table 4 {of the submittal] below compares the average of all test runs for top performers in the three coal subcategories compared to the stoker and hybrid suspension biomass subcategories:

Here it can be observed that the two biomass subcategories differ substantially – by one or two *orders of magnitude* - from the coal subcategories and would seem to merit their own subcategories as described in their petitions. In contrast, there are relatively minor differences in the three coal subcategories.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 15.

Commenter Name: Steve Gossett

Commenter Affiliation: Eastman Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3669-A2

Comment Excerpt Number: 14

Comment: Eastman recognizes that EPA is limited to working with the data at its disposal for top performing units when calculating emission limits. However, this example illustrates the absurd results that come from EPA's decision to subcategorize within the family of coal boilers. As discussed earlier in these comments (see Section C.1, above), boiler design is fundamentally a function of fuel rank. To establish separate subcategories for high rank coal boilers versus low rank coal boilers, as EPA did in the Utility MACT, is logically and technically sound. To build upon that logical construct and establish subcategories for high rank coal boilers, low rank coal boilers, and even lower rank biomass boilers is also logically and technically sound. But to attempt to subcategorize within the family of high rank boilers, as EPA has effectively done by attempting to segregate industrial coal boilers based on their fuel feed systems, is illogical and produces absurd results. EPA should abandon this ill-conceived construct and instead treat all coal boilers as a single subcategory for PM emission limits.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 15.

Commenter Name: Steve Gossett

Commenter Affiliation: Eastman Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3669-A2

Comment Excerpt Number: 15

Comment: The data among EPA's top performers do not indicate there is a statistically significant difference in PM emission rates between stokers, PC, and FB coal boilers. Finally, either ESPs or fabric filters can be deployed equally to effectively control PM/TSM emissions from any of these three boiler types.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 15.

Commenter Name: Steve Gossett

Commenter Affiliation: Eastman Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3669-A2

Comment Excerpt Number: 13

Comment: Eastman also disagrees with EPA's premise that PM emissions are solely or primarily a function of the type of fuel feed system employed to fire the unit (i.e. PM emission differ for stoker coal units versus pulverized coal units versus fluidized bed units). Eastman owns and operates coal units with a variety of fuel handling & firing systems (deep bowl and shallow bowl pulverizers, attrition pulverizers; spreader stokers) and particulate collectors (precipitators and fabric filters). Eastman's extensive operating experience with a wide variety of units indicates that the size distribution of PM emission is highly dependent upon the firing system, as shown below in Table 5 [see submittal for Table 5]. However, Eastman's experience also teaches that the PM *emission rate* is also influenced by the size and design criteria of the *particulate collector* in addition to the firing system of the boiler. EPA's proposed PM limits presume, in contrast, that the firing system is the sole determinant of the PM emission rate. EPA concludes from its analysis of ICR test data that stoker coal units should comply with a lower PM emission standard (0.028 lb/MMBtu) than pulverized coal units (0.044 lb/MMBtu). But consider in Table 6 [see submittal for Table 6] the difference between Eastman's No. 19 Boiler (stoker coal boiler with an ESP) and No. 26 Boiler (pulverized coal boiler with an ESP).

If EPA's logical construct that PM Emission Rate was solely determined by the firing system were true, it would follow that the stoker coal unit (No. 19) would have a lower PM emission rate than the pulverized coal unit (No. 26). But instead the opposite is true: The PM emission rate from the stoker coal unit is an order of magnitude higher than the rate from the pulverized coal unit. The explanation can be seen in the design of the precipitator. The specific collection area (SCA) is an indication of how large the collecting surface of the precipitator is relative to the gas flow passing through it. Because No. 26 Boiler has a very large SCA (i.e. its ESP is very large, relative to the size of the boiler) compared to No. 19 (i.e. with a relatively small ESP, relative to the size of the boiler), No. 26 has a much lower PM emission rate compared to No. 19. It is clear that the emission rate of No. 26 has little if anything to do with the fact that it is a pulverized coal unit.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 15.

Commenter Name: Bart Sponsellar

Commenter Affiliation: Wisconsin Department of Natural Resources

Document Control Number: EPA-HQ-OAR-2002-0058-3527-A2

Comment Excerpt Number: 8

Comment: EPA is proposing that particulate emissions are a combustion based pollutant instead of a fuel-based pollutant. The Department agrees that the generation of particulate is primarily a function of combustion with good combustion practice being the first measure in reducing particulate emissions. However, particulate emission rates are being used as a surrogate for non-mercury metal emissions. As such, we must recognize that the reduction of the

particulate emissions, which are associated with metal emissions, is likely achieved through particulate control equipment such as fabric filters and electrostatic precipitators (ESP). For this reason EPA must rely primarily on controlled particulate emission rates relative to determining MACT for non-mercury metal emissions. However, as noted in the "solid fuel" discussion, the emission of all metals is first related to the concentration of metals in the fuel.

The Department asks EPA to clarify how designating particulate as a combustion-based pollutant relates to acting as a surrogate for non-mercury metal emissions. The Department believes such a designation is useful if good combustion is used in conjunction with operating particulate control equipment. This combined type of parametric monitoring approach could potentially be applied in combination with fuel testing to allow stack testing of metals every two years instead of the default annual test cycle.

Response: The TSM measurement, which directly quantifies the HAP metals rather than relying on a surrogate, is a more direct measurement of HAP than PM and is, therefore, appropriate as a pollutant group for regulation with numeric emission limits. Several petitioners to the March 2011 final rule provided information to support the position that PM should be considered a combustion-based pollutant rather than a fuel-based pollutant. After assessing the points raised by the petitioners, the EPA determined that PM emissions are influenced both by fuel type and unit design. Therefore, it is appropriate to treat PM as a combustion based pollutant. Differences in PM particle size, applicability of air pollution controls to units combusting various fuels, and the lack of demonstration of certain control technologies on certain designs of boilers suggested that PM is more appropriately classified as a combustion-based pollutant limits. For TSM in the March 2011 final rule, we chose to use PM as a surrogate. Most, if not all, TSM emitted from combustion sources will appear on the flue gas fly-ash. Therefore, the same control techniques that would be used to control the fly-ash PM will control TSM.

Commenter Name: Mary Sullivan Douglas

Commenter Affiliation: National Association of Clean Air Agencies (NACAA)

Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1

Comment Excerpt Number: 16

Comment: Under EPA's current and proposed procedures, creating larger numbers of subcategories usually leads to higher MACT floors in two ways. First, if a small number of the best performers (e.g., fuel cells) can be culled from a larger group into its own subcategory, the MACT floor for the larger group (the wood-fired boilers) will rise. Second, because the small group will have a small number of tests, the statistical variability of the small group will also increase, leading to MACT floor increases for both the larger group and the smaller group. EPA's decision to create separate subcategories for PM emissions based on the design of the combustion chamber creates a situation where a unit with highly variable emissions is classified as a top performer, based on EPA's inappropriate definition of best performing unit. Since that unit has many more test results than others in the group, EPA's pooled UPL process causes that unit to dominate and results in a limit that is technically invalid. The resulting proposed limits are often substantially higher than the highest emitting unit. [See submittal for Chart 1 showing PM emissions for Coal FB units.]

Response: EPA disagrees with the commenter. For the reasons identified in the preamble to the December 23, 2011 proposed reconsideration of the rule, the final rule has retained the regulation of PM as a combustor-based pollutant for units designed to combust biomass or bio-based solid fuel. However, all units designed to combust coal or fossil-derived solid fuels (regardless of combustor design) are subject to a single coal-based PM standard in the final rule.

The methodology used to determine the MACT floors was consistent in all cases. The situation the commenter is referring to is unique in that for this particular subcategory there were numerous PM test results (158 test runs) for the 5 best performing units making up the MACT floor. One best performing unit reported test results covering 10 years with PM emissions varying by a factor of 5 over that time period.

Commenter Name: Ahmed Idriss, Capital Power Corporation

Commenter Affiliation: CPI USA North Carolina (CPI NC)

Document Control Number: EPA-HQ-OAR-2002-0058-3524-A1

Comment Excerpt Number: 3

Comment: In the Proposed Rule, EPA proposes treating PM as a combustion based pollutant by adding 7 subcategories for PM. This subcategorization approach would significantly limit the number of units used to establish a MACT floor. Therefore, CPI NC does not support this approach and recommends that PM remain treated as a fuel based pollutant.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3525-A1, excerpt 16. The EPA further notes that its subcategories are based on differences in class, type, or size among the affected units. The number of units in each resulting subcategory is not relevant to EPA's analysis of and conclusions regarding the appropriateness of defining subcategories within the boiler and process heater source category.

Commenter Name: Ahmed Idriss, Capital Power Corporation

Commenter Affiliation: CPI USA North Carolina (CPI NC)

Document Control Number: EPA-HQ-OAR-2002-0058-3524-A1

Comment Excerpt Number: 2

Comment: CPI NC does not support the EPA's methodology for establishing emissions limits based on single fuel type facilities. In the Proposed Rule, EPA proposes to establish emissions limits for fuel subcategories by using data from the top 12% of units that use, for example, at least 90% biomass in the case of PM and CO biomass categories, and 90% coal in the case of PM and CO coal categories. While this method may be appropriate for single fuel facilities, it does not reasonably consider maximum achievable control technologies for facilities utilizing multiple fuel types. Capital Power recommends using fuel and fuel mixture variability for multi-fuel facilities in determining the top 12% of such facilities for the MACT floor. This approach is more reasonable because it captures each facility's operational and fuel variability.

Response: The EPA disagrees with establishing MACT floor emission limitations for multi-fuel facilities. The EPA also disagrees that the maximum achievable control technology identified for specific pollutants and fuels would not apply to a unit which combusts a mixture of fuels. Each boiler or process heater subject to the rule must demonstrate compliance with emission

limits for a subcategory based on the amount each fuel in the mixture is combusted. The EPA believes that, if facilities install controls in order to determine compliance with an emission limitation, that the performance of the control will be able to account for the operational and fuel variability that occur at the facility.

Commenter Name: Roger Martella

Commenter Affiliation: National Alliance of Forest Owners (NAFO)

Document Control Number: EPA-HQ-OAR-2002-0058-3519-A1

Comment Excerpt Number: 7

Comment: While EPA's proposed revisions to the PM emissions limits demonstrate an attempt at increasing flexibility and reducing regulatory burdens, it fails to produce this effect for many existing biomass boilers. EPA's decision to create PM subcategories for coal- and biomass- fired boilers, resulted in uneven results and in several cases we are concerned that the emissions limits included in the proposed rule remain too stringent. As explained in our prior comments, the current PM emissions limits will require biomass facilities to install costly new control technology and incur higher operating costs, creating a risk that facilities will avoid biomass fuels and turn instead to fossil fuel alternatives. But, rather than relieving this burden, the proposed PM emissions limits for existing "stokers/sloped grate/others designed to burn wet biomass fuel" – the most common type of biomass boiler currently in use – are actually more stringent than those under the current rule. Further reductions in PM emissions limits for the majority of existing biomass boilers will have a significant and detrimental effect on the viability of these boilers as alternatives to fossil fuel boilers. The wood products industry, which employs the majority of the wet stoker boilers, was significantly impacted by the recession and is still struggling to recover. EPA must reassess the emissions limits for existing wet biomass stoker boilers and adopt more reasonable standards that can be achieved in practice and will satisfy legal requirements, without prohibitive costs that will further threaten the health and viability of this important industry.

Response: For the reasons identified in the preamble to the December 23, 2011 proposed reconsideration of the rule, EPA disagrees with the commenter that the revisions to the PM emission limitations fail to increase flexibility between the different types of boilers in operation in the U.S. Comments pertaining to the economic impact of the rule are not relevant to the calculation of the MACT floor limits, and are outside the scope of this comment response document.

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 73

Comment: Major source emissions for PM (new sources) are as follows. The area source standard is 0.03 lb/mmbtu for boilers greater than 30 mmbtu/hr. It makes no sense for new major sources to be permitted to emit more PM than area sources. [See submittal for table of new source PM limits from area and major rules.]

Response: The PM emission limitations for new sources have been revised for all subcategories in the final amended rule. For all biomass subcategories, the revised new source PM emission limitation is at or below the area source limit of 0.03 lb/MMBtu in the final rule based either on recalculation, incorporating new data, or a beyond-the-floor determination. Refer to the preamble and the memorandum “Beyond the Floor Technology Analysis for Major Source Boilers and Process Heaters (Revised August 2012)” for a discussion of the rationale to select a beyond the floor level of control for new source PM emission values.

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 2

Comment: EPA’s expansion of the number of subcategories in its reconsideration proposal, appears to reflect the agency’s proposed conclusion that particulate matter (PM) is a "combustion-related" pollutant. 76 Fed. Reg. 80598, 80607 (December 23, 2011). The agency now claims that the differences in PM size from different boilers and the lack of demonstration of certain technologies on some boilers "(e.g. fabric filters are not used on any hybrid suspension grate boilers)" warrants proposing different limits for them. *Id.* Thus, EPA proposes to set separate PM standards for stoker, fluidized bed, and pulverized coal (PC) units that are "designed to burn" coal. *Id.* at 80601. EPA also proposes separate PM standards for "Biomass Wet Stoker/Sloped Grate/Other," "Biomass Kiln-Dried Stoker/Sloped Grate/Other," "Biomass Fluidized Bed," "Biomass Suspension Burner," "Biomass Dutch Ovens/Pile Burners," "Biomass Fuel Cells," and "Biomass Hybrid Suspension Grate." *Id.* at 80601. Regardless of whether PM can be viewed as a combustion related pollutant, EPA has not shown that the units in these purported subcategories are of a different class, type, or size. In particular, that some may not already have deployed a fabric filter is no excuse for subcategorizing them. EPA does not claim that any of these units are so designed that the use of fabric filters is infeasible. Thus, the agency’s decision to set separate (and significantly less protective) standards for them is a blatant attempt to subcategorize by emission levels or control measures. Any such subcategorization exceeds EPA’s authority and frustrates the purpose of the § 112’s floor language. If EPA wishes to set separate standards for units, the agency must show why any alleged design differences matter – i.e., would necessarily prevent a unit with a particular design from meeting standards set for a larger group of units including those with other designs – and support that explanation with record evidence. EPA has not done so here.

Response: The EPA disagrees with the commenter that the EPA has not shown that the subcategories based on PM as a combustion-related pollutant are of a different class, type, or size. The EPA has broad discretion to create subcategories which distinguish among “classes, types, and sizes of sources.” See CAA section 112 (d)(1). The EPA may exercise that discretion if sources are rationally distinguishable due to some difference in class, type, or size. Moreover, any basis for subcategorizing should be related to an effect on emissions, rather than to some difference among sources which does not affect emissions performance. The EPA may also exercise this discretion on a pollutant-specific basis, because the difference in class, type, or size may only have practical significance for certain HAP.

As noted at proposal, several petitioners provided information to support the position that PM should be considered a combustion-based pollutant rather than a fuel-based pollutant. After assessing the points raised by the petitioners, the EPA determined that PM emissions are influenced both by fuel type and unit design. Therefore, it was determined appropriate to treat PM as a combustion-based pollutant because the emissions from the different combustor types will differ in PM particle size, PM loading, and exhaust temperature which affects the technical feasibility and applicability of applying emission control technology. Therefore, the EPA proposed separate PM limits for each combustion-based subcategory.

The EPA disagrees that it is unreasonable to establish separate PM limits for each combustion-based subcategory. This subcategorization approach is appropriate because there are differences in the PM emission characteristics and the in the technical feasibility of applying control technology for the various combustion-based subcategories. We also disagree that the fact that the availability of similar control options negates the legitimacy of a subcategorization approach. In fact, the controls available to reduce PM are generally available for all types of sources, but that does not mean that all classes, types and sizes of sources are the same and must be included in the same subcategory. As noted above, section 112 provides EPA with broad discretion to subcategorize within a source category, and the terms “class, type, or size” are similarly broad terms that encompass a wide range of differences among sources, not just differences in available control technologies. Had Congress intended for EPA’s subcategorization authority to be limited in the manner commenters suggest, it could have done so, and it certainly would not have used such wide-ranging terms (class, type, and size) to describe the criteria for subcategorization.

In this action, EPA combined all coal boilers into a single subcategory with one set of PM limits. The EPA carefully reconsidered the possibility of retaining separate PM limits for the combustion-based subcategories and concluded that separate subcategories for PM are warranted for the units designed to burn biomass. We agreed with commenters, see response to EPA-HQ-OAR-2002-0058-3510-A1, excerpt 15, that there are not enough differences in PM from the three types of coal-fired boilers to justify subcategorization of such units but that biomass units merit their own separate subcategories for PM emissions. Therefore, in the final rule, the EPA combined all coal boilers into one subcategory with a single set of PM emission limits.

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 3

Comment: EPA’s approach to subcategorization has resulted in significantly less protective emission limits for some of the worst emitters, not because these units are truly of a different class, type, or size but simply because the agency’s subcategories have isolated units that have not taken measures to reduce their emissions. For example, EPA’s proposed PM standard for existing Biomass Hybrid Suspension Grate boilers is .44, more than ten times higher than the .039 limit in EPA’s final rule. Allowing these units to emit ten times more PM pollution merely because they have not yet installed control technology rewards the worst polluters and punishes people who will be forced to live near sources that emit more than ten times the emissions of

hazardous metals and PM than cleaner boilers, as well as the responsible boiler owners who have installed controls who are placed at a competitive disadvantage.

Response: As stated in the response to comment EPA-HQ-OAR-2002-0058-3511-A1, excerpt 2, we continue to believe that it is appropriate to subcategorize based on boiler design for combustion-related pollutants which we have determined PM to be for boilers types designed to combust biomass. The PM limit proposed for existing Biomass Hybrid Suspension Grate boilers is the result of the MACT floor analysis which is based on the PM emissions from the best performing units in the subcategory, as mandated by section 112 of the Clean Air Act. A beyond-the-floor analysis was conducted but the analysis shown that going beyond the floor was not cost-effective. The cost-effective results was \$525,000 per ton of PM or \$260 million per ton of TSM. Contrary to the commenter's assertion, EPA is not subcategorizing units based on whether or not control technologies have been installed. Rather, we have subcategorized based on the different design types of units because different designs have different emission characteristics which influence the feasibility of effectiveness of applying emission control techniques. These design differences have an effect on organic HAP emissions, as well as on PM emissions. Hybrid suspension grate boilers are designed differently from other boiler types designed to burn biomass in order to combust the high moisture bagasse generated from the processing of sugar cane. The PM MACT floor limit for this subcategory is based on the best performing 5 units within the subcategory since there is less than 30 units within the subcategory. Of these 5 best performing hybrid suspension grate boilers, two are controlled with ESP and the others with wet scrubbers.

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 72

Comment: In our review of biomass facility permits from around the country, we have never seen fuel moisture taken into consideration when setting emission limits at facilities.

EPA states that one reason for sub-categorization is its decision to treat PM as a "combustion-based pollutant". Page 80607 states:

Differences in PM particle size, applicability of air- pollution controls to units combusting various fuels, and the lack of demonstration of certain control technologies on certain designs of boilers (e.g., fabric filters are not used on any hybrid suspension grate boilers) suggest that PM is more appropriately classified as a combustion-based pollutant. Therefore, the EPA is now proposing separate PM limits for each "combustion-based" subcategory.

However, this does not correspond to real-world permitting. It should make no difference if a baghouse is demonstrated, an ESP can do about as well as a baghouse. EPA's proposed PM limit for suspension based boilers is 0.05 lb/mmBtu, much higher than is achievable with an ESP. The limit should be lower.

Response: We disagree with the assertion that fuel moisture does not affect emissions. Moisture content of the fuel will affect the combustion conditions which will affect the emissions of certain pollutants, mainly CO and NOx. One example of the effect of moisture is its effect on

the control technology of water/steam injection used to reduce NOx emissions from stationary gas turbine. NOx formation is increased under high temperature combustion conditions, whereas CO and organic HAP are reduced by high temperature combustion conditions, as demonstrated by the use of thermal oxidizers on offgases to control organic HAP emissions. The introduction of moisture into the combustion process has the effect of lowering combustion temperature which would decrease NOx formation (i.e., reduced NOx emissions) but have the opposite effect of decreasing CO and organic HAP reductions (i.e., increasing CO and organic HAP emissions). While the commenter asserts that they have never seen fuel moisture taken into consideration when setting emission limits at facilities, it provides no information, including the technical background information used in drafting the permits for biomass facilities, to support this assertion.

See response to comment EPA-HQ-OAR-2002-0058-3511-A1, excerpt 3 for a discussion of the PM emission limit for suspension based boilers.

Commenter Name: Mary Sullivan Douglas

Commenter Affiliation: National Association of Clean Air Agencies (NACAA)

Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1

Comment Excerpt Number: 15

Comment: EPA proposes to establish seven subcategories of wood-fired boilers¹³ – wet stoker, dry stoker, fluidized bed, suspension, dutch oven, fuel cell and hybrid suspension – based on differences in the design of the combustion chamber of these units. However, most boilers and, in particular, the best-performing units, are equipped with PM control devices ranging in effectiveness from cyclones and multi-cyclones to electrostatic precipitators and fabric filters. The performance of the installed PM control device governs the level of PM and TSM emissions to a far greater extent than differences in design of the combustion unit itself. Indeed, in the stoker/sloped/other dry biomass subcategory we note that each of the units in the subcategory is only served by cyclone or multiclone particulate matter control devices, while in other subcategories most of the units are equipped with more effective fabric filter or electrostatic precipitator control devices. We do not believe that EPA is authorized to create a class of “poorly controlled units” and recommend that no separate subcategories be authorized for PM or TSM.¹⁴

[Footnotes]

(13) NACAA has raised a concern that differences in the combustion properties of “wet” wood and “dry” wood might

(14) These devices, along with sulfur dioxide and nitrogen oxide controls may also affect emission levels of hydrogen chloride and mercury.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3511-A1, excerpt 2.

Commenter Name: Robert E. Hunzinger

Commenter Affiliation: Gainesville Regional Utilities (GRU), Florida

Document Control Number: EPA-HQ-OAR-2002-0058-3488-A1

Comment Excerpt Number: 5

Comment: EPA has taken a different approach to establishing air toxics emission limits in the Reconsideration rule as compared to the final rule. EPA has created a distinction between "fuel-based" air toxics (mercury and HCL) and "combustion-based" air toxics (PM and CO) for establishing emission limits.³ EPA has proposed only one Hg limit and one HCl limit each for solid fuels and liquid fuels without regard to specific fuel types or boiler technologies. GRU is concerned that this approach does not recognize the wide range of mercury and chloride content of solid and liquid fuels. In addition, the valence state of mercury in the fuel has a direct impact of the removal efficiency of emission control systems.

However, since PM and CO are "combustion-based" pollutants, EPA has concluded that specific emission limits related to different combustion technologies are warranted. On this basis, EPA has proposed separate emission limits for fourteen different types of boilers to be covered by the rule, including three different types of coal units, two different types of liquid fuel units, and seven different types of biomass units, resulting in a greater number of subcategories than any prior industrial boiler MACT rule or proposal. GRU believes that the real issue is that both fuel composition and boiler combustion characteristics impact emissions as well as the effectiveness of control systems. We believe fuel type and composition should be considered in setting a NESHAPS emission limit.

[Footnote]

(3) Note PM is a surrogate standard for non mercury metals while CO is a surrogate for organic toxics.

Response: The EPA disagrees that the emission limitations for mercury and hydrogen chloride for solid and liquid fuels do not properly recognize the wide range of those pollutants which may be found in different types of solid and liquid fuels. The mercury and hydrogen chloride limits for solid fuels were based on a 99% UPL derived from emissions from both coal and biomass fuels. Similarly, the mercury and hydrogen chloride limits for liquid fuels were based on a 99% UPL derived from emissions from both distillate- and residual-type fuel oils. Two types of data variability were evaluated to determine the emission levels achieved by the best performing sources over the long term, the statistical variability and fuel analysis variability. The statistical variability (99% UPL) evaluates variability considering variability in control device performance, unit operations, and fuels fired during the test. Fuel variability considers the variability in the fuel constituents (mercury, metals, chlorine) outside of the test period. For this reason, the EPA believes that the mercury and hydrogen chloride limits properly account for the natural mercury and hydrogen chloride variation that may be found in different types of solid or liquid fuels.

For the reasons specified in the preamble to the December 23, 2011 proposed reconsideration of the rule (76 FR 80598), the EPA believes that the largest factor in emissions of PM (and CO) is the combustion style. For this reason, EPA has retained PM and CO as combustion-based pollutants in the final rule.

Commenter Name: Arthur N. Marin

Commenter Affiliation: Northeast States for Coordinated Air Use Management (NESCAUM)

Document Control Number: EPA-HQ-OAR-2002-0058-3506-A1

Comment Excerpt Number: 12

Comment: NESCAUM is concerned about the large variation in PM emission limits of the reconsidered major source rule for similar boilers in different subcategories (76 FR 80601, Table 1). Among existing biomass-fueled unit subcategories, the PM emission limits range from 0.029 lb/MMBtu for wet stoker units to 0.44 lb/MMBtu for hybrid suspension/grate units. In the “final” major source rule, all existing solid fueled units had been subject to an emission limit of 0.039 lb/MMBtu. The PM emissions limits for some biomass fuel subcategories therefore represent increases by approximately an order of magnitude from the PM emission limit in the “final” rule. Also disturbing is that several of the proposed MACT emission limits are less stringent than that required for biomass units under the New Source Performance Standard (NSPS), which established an emission limit for PM of 0.030 lb/MMBtu.

Based on these inconsistencies, it is clear that the analysis of the biomass units has been parsed to a degree that the analysis is no longer valid, and results in PM emissions limits that are not representative of the maximum achievable control technology as required by Section 112 of the CAA. Therefore, NESCAUM urges EPA to continue with the biomass PM emission limits promulgated in the March 21, 2011 final rule (76 FR 15608).

Response: For the reasons specified in the preamble to the December 23, 2011 proposed reconsideration of the rule (76 FR 80598), the EPA is treating PM as a combustor-based pollutant in the final rule. PM emissions have been shown to vary as a function of combustion style, most notably for the combustion of biomass or bio-based solid fuels. As such, the EPA feels it is necessary to regulate PM combustion on a combustor design basis. In setting emissions standards, the EPA must consider the emission variability of the lowest-emitting sources within the subcategory. The EPA has achieved this by establishing a 99% UPL based on the reported emissions data for the lowest-emitting sources in the subcategory. The wide range of PM emission limitations for the subcategories is evidence that PM emissions vary greatly with combustor design. For these reasons, the EPA believes it is appropriate to subcategorize biomass combustors for PM, based on our conclusion that PM is a combustion-based pollutant.

6C. TSM Alternative for non-Hg metals (solid and gas 2 fuels)

Commenter Name: David A. Buff, Golder Associates Inc.

Commenter Affiliation: Florida Sugar Industry (FSI)

Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1

Comment Excerpt Number: 1

Comment: The FSI agrees with and supports EPA’s decision to establish a TSM standard as an alternative to the PM standard. The proposed TSM standard requires a direct measurement of eight metallic HAPs that are emitted from a boiler, rather than relying on PM as a surrogate for non-mercury metallic HAPs. The TSM standard will provide a more accurate measurement of the metallic HAPs emitted from the FSI’s boilers.

If the proposed TSM standard is not adopted, many of the FSI boilers may need new, expensive emissions controls based on the boilers’ PM emissions, even though the metallic HAPs

emissions from those boilers do not warrant the installation of the new PM controls. Stated differently, if the proposed TSM standard is not adopted, the FSI will be required to install new air pollution control equipment at great expense to control metallic HAPs, even though the new equipment will not provide meaningful reductions in the emissions of metallic HAPs.

Response: The EPA thanks the commenter for their support.

Commenter Name: Dirk J. Krouskop

Commenter Affiliation: MeadWestvaco Corporation (MWV)

Document Control Number: EPA-HQ-OAR-2002-0058-3493-A1

Comment Excerpt Number: 14

Comment: MWV supports the inclusion of Total Select Metals (TSM) as an alternative for particulate matter limits. EPA has proposed TSM limits as alternatives to PM limits for coal, biomass, and gas 2 units. This approach has the ability to provide cost benefits to certain units that have low metal HAP emissions, but might not be equipped with the very best in particulate controls. MWV is concerned that in its current construct these limits are too low to be of much practical value to individual boilers. MWV believes, however, that EPA should consider fuel and emissions variability in determining what these limits should be.

Response: The EPA thanks the commenter for their support. The EPA has considered fuel and emissions variability for TSM in the final rule. Fuel and emission variability were calculated using the same methods and assumptions as used in the analyses conducted for PM, HCl, and mercury. See the memorandum "Revised MACT Floor Analysis (August 2012) for the Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants – Major Source" in the docket. **Commenter Name:** Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 1

Comment: *ACC supports the inclusion of alternate TSM limits* ACC believes inclusion of a total selected metals (TSM) emission limitation as an alternative to the particulate matter (PM) emission limits in the Final Boiler Rule is appropriate, since the emissions of these non-mercury metals are the hazardous air pollutants (HAPs) the standard targets for regulation and reduction. We believe that a TSM option will provide greater flexibility for sources while still reducing the emissions of non-mercury HAP metals. This will offer the opportunity for sources to achieve low metal HAP emissions similar to those achieved with PM, but potentially at a lower cost.

Response: The EPA thanks the commenter for their support.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 2

Comment: As the implementation of the Final Boiler Rule will be extremely costly for industry, the use of the TSM alternative could help provide some cost savings by avoiding the installation and operation of PM continuous parameter monitoring system (CPMS) for units >250 MMBtu where the TSM limits are viable.

Response: The EPA thanks the commenter for their support.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 86

Comment: EPA has proposed TSM limits as alternatives to PM limits for coal, biomass, and gas 2 units. EPA's recently signed Mercury and Air Toxics Standard also provides a choice between complying with a PM or a TSM standard for certain EGUs. There are some industrial boilers (e.g., most liquid and gas-fired units) that do not have any PM controls and there are some industrial boilers (e.g., some biomass units) that do not have sophisticated PM controls, but have low metals emissions.

However, to enhance flexibility and cost-effectiveness in the proposed rule, we support EPA's inclusion of a TSM emission limitation as an additional compliance option, allowing either fuel analysis or metals stack testing at the same frequency as the PM stack testing requirements for ongoing compliance. This approach will allow sources to comply using fuel analysis instead of costly annual or triennial stack testing and to design emissions reduction strategies around HAP metals instead of PM as their surrogate.

Response: The EPA thanks the commenter for their support.

Commenter Name: Stephen E. Woock

Commenter Affiliation: Weyerhaeuser Company

Document Control Number: EPA-HQ-OAR-2002-0058-3523-A1

Comment Excerpt Number: 13

Comment: We support EPA's proposal to include TSM limits as an alternative to the PM surrogate limit for Hazardous Air Pollutant (HAP) metals. In aggregate the eight metals EPA selected provide an adequate surrogate measure of all metal HAPs, and this approach may provide compliance flexibility where metal emissions are low and addition of PM controls is unnecessary or infeasible.

Response: The EPA thanks the commenter for their support.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 42

Comment: CIBO supports EPA's decision to include a total selected metals (TSM) option for solid fuels into the Propose Reconsideration Rule. In its Petition for Reconsideration, CIBO stated that the "TSM option would offer the opportunity for sources to achieve low metal HAP emissions similar to those achieved with the use of PM as a surrogate for HAP metals, but potentially at a lower cost." Furthermore, CIBO noted that a TSM option provides for additional flexibility for Boiler MACT compliance.

EPA has proposed "TSM limits for each subcategory of units that combust solid fuels or Gas 2 fuels." 76 Fed. Reg. 80,606. Sources will also have the compliance option of meeting PM emission limits as well. EPA noted "the TSM measurement, which directly quantifies the HAP metals rather than relying on a surrogate, is a more direct measurement of HAP than PM and is, therefore, appropriate as a pollutant group for regulation with numeric emission limits." *Id.* Furthermore, EPA will include 8 (excluding cobalt and antimony), as opposed to 10, metals for measurement because more test data are available for the eight metals. *Id.*

The TSM option for solid fuels preserves flexibility and may lower compliance costs for sources. TSM does not provide any less environmental protection, but is simply another way for sources to measure compliance with non-mercury metals emission limits.

Response: The EPA thanks the commenter for their support.

Commenter Name: Vickie Woods

Commenter Affiliation: Division of Air Quality, North Carolina Department of Environment and Natural Resources (NCDENR)

Document Control Number: EPA-HQ-OAR-2002-0058-3663-A2

Comment Excerpt Number: 3

Comment: NC DAQ supports the concept of using the 8 total selected metals (TSM) as an alternative to PM emission limits and as a surrogate for non-mercury metal HAP. The TSM include arsenic, beryllium, cadmium, chromium, lead, manganese, nickel, and selenium. We also agree with use of 8 of the 10 HAP metals for which EPA has emission data, as the emission controls used to reduce the 8 metals would be equally effective in reducing the other 2 metals, antimony and cobalt.

Response: The EPA thanks the commenter for their support.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 60

Comment: EPA has proposed alternative TSM limits to PM limits for each subcategory of units that combust solid fuels or Gas 2 fuels. Establishing an alternate standard for TSM is appropriate and provides sources with flexibility to demonstrate compliance through either direct metal HAP measurement or through total PM measurement – either method achieving the required level of HAP pollution mitigation. Thus, we fully support establishing these alternative emission limits.

Response: The EPA thanks the commenter for their support.

Commenter Name: Michael D. Wendorf

Commenter Affiliation: FMC Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3453-A1

Comment Excerpt Number: 1

Comment: FMC Corp. supports EPA's decision to include an emission limit for TSM as an alternative *to* the PM limits specified in the final rule. It is logical and appropriate, whenever reasonable, to directly measure the pollutant(s) in question rather than to rely upon a surrogate.

Response: The EPA thanks the commenter for their support.

Commenter Name: Robert E. Hunzinger

Commenter Affiliation: Gainesville Regional Utilities (GRU), Florida

Document Control Number: EPA-HQ-OAR-2002-0058-3488-A1

Comment Excerpt Number: 2

Comment: GRU supports the reconsidered rule provision that allows an option to comply with a total metal standard in lieu of the total filterable PM standard.

Response: The EPA thanks the commenter for their support.

Commenter Name: Lee Zeugin and Lauren Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1

Comment Excerpt Number: 29

Comment: [Footnote]

(14) EPA also proposes to add an alternative total selected metals limit, which could be met using performance stack tests and operating parameters rather than PM CEMS. UARG supports addition of this option.

Response: The EPA thanks the commenter for their support.

Commenter Name: Timothy Serie

Commenter Affiliation: American Coatings Association (ACA)

Document Control Number: EPA-HQ-OAR-2002-0058-3502-A1

Comment Excerpt Number: 4

Comment: ACA generally supports the following proposed changes in the Boiler MACT rule: Revision that sources have the option of either meeting a total selected metals (TSM) limit for each category or alternative particulate matter limits

Response: The EPA thanks the commenter for their support.

Commenter Name: Arthur N. Marin
Commenter Affiliation: Northeast States for Coordinated Air Use Management (NESCAUM)
Document Control Number: EPA-HQ-OAR-2002-0058-3506-A1
Comment Excerpt Number: 19

Comment: The EPA is proposing to add a more direct measurement of representative HAP metals emissions as an alternative to use of a surrogate PM emission limits (FR 75 80606). NESCAUM supports this alternative approach to meeting the emission standards because it more directly addresses the emissions of pollutants that the EPA intends to regulate through this rule.

Response: The EPA thanks the commenter for their support.

Commenter Name: Michael L. Krancer
Commenter Affiliation: Pennsylvania Department of Environmental Protection (DEP)
Document Control Number: EPA-HQ-OAR-2002-0058-3507-A1
Comment Excerpt Number: 1

Comment: The EPA has proposed emission limits for alternate total selected metals (TSM) as an alternative to the particulate matter (PM) limits. Alternative TSM limits were created for each subcategory of units that combust solid fuels or "Gas 2" fuels. These subcategories will have the option of complying with either the TSM limits or the alternative PM limits. For this rule, TSM includes eight metals: arsenic, beryllium, cadmium, chromium, lead, manganese, nickel and selenium. The DEP agrees with EPA's proposed alternative TSM limits for units that combust solid fuels or "Gas 2" fuels.

Response: The EPA thanks the commenter for their support.

Commenter Name: Bart Sponsellar
Commenter Affiliation: Wisconsin Department of Natural Resources
Document Control Number: EPA-HQ-OAR-2002-0058-3527-A2
Comment Excerpt Number: 1

Comment: EPA has proposed that sources can comply with total selected metals (TSM) limitations for solid and biomass fueled boiler source categories in lieu of complying with the particulate emission limitation. The Department supports this approach as it directly regulates the toxic pollutants of concern. The Department does encourage EPA to review any additional data it receives in setting the total metals emissions limits.

Response: The EPA thanks the commenter for their support.

Commenter Name: J. Michael Geers
Commenter Affiliation: Duke Energy
Document Control Number: EPA-HQ-OAR-2002-0058-3543-A1
Comment Excerpt Number: 4

Comment: In the December 23, 2011 proposal, EPA included an emission limit for TSM as an alternative to the PM limits in the final rule, particularly for biomass units. After assessing the available data, the EPA determined that inclusion of these limits was appropriate for some subcategories, and the EPA proposed TSM limits for each subcategory of units that combust solid fuels or Gas 2 fuels. Duke Energy supports this change and believes is it appropriate to give sources the flexibility to meet either the TSM limit or the alternative PM limit.

Response: The EPA thanks the commenter for their support.

Commenter Name: Annabeth Reitter
Commenter Affiliation: NewPage Corporation
Document Control Number: EPA-HQ-OAR-2002-0058-3662-A2
Comment Excerpt Number: 4

Comment: NewPage Corporation supports the use of the TSM alternative.

Response: The EPA thanks the commenter for their support.

Commenter Name: Douglas A. McWilliams
Commenter Affiliation: American Municipal Power
Document Control Number: EPA-HQ-OAR-2002-0058-3685-A2
Comment Excerpt Number: 48

Comment: EPA has included numerous compliance demonstration alternatives in the Proposed Rule. AMP appreciates EPA's efforts to provide flexibility to the regulated community and supports EPA's inclusion of the following optional compliance alternatives:

- Compliance with a TSM limit in lieu of a PM limit

Response: The EPA thanks the commenter for their support.

Commenter Name: Lorna Fear
Commenter Affiliation: Visual Cue Thermal Imaging
Document Control Number: EPA-HQ-OAR-2002-0058-3770-A1
Comment Excerpt Number: 1

Comment: I am concerned about potential manipulation of the allowance of alternative total selective metals emissions limits.

Response: The EPA acknowledges this comment.

Commenter Name: David A. Buff, Golder Associates Inc.
Commenter Affiliation: Florida Sugar Industry (FSI)
Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1
Comment Excerpt Number: 2

Comment: FSI agrees with EPA's decision to establish the TSM standard by using the sum of 8-metals, rather than 10-metals (i.e., 8-metals plus antimony and cobalt). More data are available for the 8-metals than the 10-metals, and thus the establishment of a TSM standard based on eight metals is more likely to be appropriate and scientifically defensible. We agree with EPA's statement in the preamble that "The use of 8 of 10 metals should have little or no impact on a facility's selection of controls to meet the standards, and the controls that would be used to reduce emissions of the eight metals would be equally effective in reducing emissions of the other two metals. Therefore, TSM can serve as a surrogate for all metallic HAP except for Hg, which the final rule regulates separately." 76 F.R. 80606.

Based on available bagasse fuel analyses for which all 10-metals were analyzed, the sum of 8-metals (excluding antimony and cobalt) and the sum of 10-metals (including antimony and cobalt) for three FSI facilities averaged as follows:

[See submittal for table]

[See submittal for Appendix A- "Bagasse Metals Fuel Analysis Data."] As shown, antimony and cobalt do not contribute significantly to the total metals content of bagasse in Florida. Similar variations are observed with bagasse in Hawaii. Consequently, the use of 8-metals rather than 10-metals will not result in an underestimation of the risk associated with metallic HAPs emissions from the FSI's boilers.

Response: The EPA thanks the commenter for their support.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 3

Comment: For purposes of the final Boiler rule, TSM would be defined as the sum of 8 non-mercury HAP metals. It would not be practical or necessary for EPA to set emission limits for each of these individual metals due to the fact that so many of them are present below detectable levels. The use of a TSM alternative is therefore appropriate, and TSM emissions can be calculated using available metals emission data for each fuel type and subcategory.

Response: The EPA thanks the commenter for their support.

Commenter Name: Dean C. DeLorey

Commenter Affiliation: The Amalgamated Sugar Company LLC (TASCO)

Document Control Number: EPA-HQ-OAR-2002-0058-3522-A1

Comment Excerpt Number: 20

Comment: If the TSM limit is fuel-based, there should not be different standards for different boilers. There should be one TSM limit for each fuel.

Response: For the coal-fired subcategory, based on public comments the EPA determined that it is appropriate to subcategorize both PM and TSM8 as a fuel-based pollutant. As the commenters pointed out, all three combustor designs for coal-fired units can fire various coal types

(bituminous, sub-bituminous, lignite, or other). Further, there is not a significant difference in PM and metal emission from each of these three combustor designs. However, for the liquid and biomass subcategories EPA finalized its proposed approach of subcategorizing PM and TSM8 on a combustor-level basis. For biomass combustor designs, the design of the combustor is related to the make-up of the fuel. Certain combustor designs are relevant for higher moisture fuels or fuels with larger particle sizes, such as, Dutch ovens and stokers. These characteristics affect the design of the boiler and the emissions profile of PM and non-Hg metals. For liquid fuels, the EPA also identified several design differences for heavy and light liquids, see the discussion in the proposal at 76 FR 80608.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 6

Comment: *EPA should allow emissions averaging if sources comply with the TSM alternative*

Emissions averaging should be allowed for units complying with TSM emission limits, as it is allowed in the final MATS rule (§63.10009). Section 63.7522 of the Reconsideration Proposal does not include emissions averaging for TSM. However, the compliance provisions (either stack testing or fuel sampling and analysis) are virtually identical as those for hydrogen chloride (HCl) and mercury (Hg) for which emissions averaging is allowed. EPA provides no explanation in the preamble to the Reconsideration Proposal for not including emissions averaging for TSM, and since emissions averaging is allowed for PM, there is no reason not to include it for facilities choosing to comply with the TSM limits.

[Footnote 2: 77 Fed. Reg. 9304, February 16, 2012]

Response: TSM is an alternative standard to the PM emission limits. This rule incorporates several flexible compliance mechanisms one being an emissions averaging alternative for PM and another being the alternative emission standard for TSM8 in lieu of the PM emission limit. The emissions averaging provision in the final amended rule has been revised to allow averaging TSM.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 88

Comment: As EPA explained in the preamble to the proposed Utility MACT rule, "the DC Circuit Court [in *National Lime II*, 233 F.3d 625] stated that EPA "may use a surrogate to regulate hazardous pollutants if it is "reasonable" to do so" and laid out criteria establishing a three-part analysis for determining whether the use" of a surrogate is reasonable. 76 Fed. Reg. at 25021. In that case, PM was found to be a reasonable surrogate for metal HAPs because: "(1) "HAP metals are invariably present in ... PM;" (2) "PM control technology indiscriminately captures HAP metals along with other particulates;" and (3) "PM control is the only means by

which facilities "achieve" reductions in HAP metal emissions." 233 F.3d at 639." 76 Fed. Reg. at 25021.

Under these criteria, TSM clearly would be a reasonable surrogate for metal HAPs (except for mercury) under the Boiler MACT. First, it is clear that covering 8 of the 10 relevant metals would assure that the individual HAPs will be "invariably present" in the 8 pollutant surrogate. Moreover, EPA explains in the proposal, "The use of 8 of 10 metals should have little or no impact on a facility's selection of controls to meet the standards, and the controls that would be used to reduce emissions of the eight metals would be equally effective in reducing emissions of the other two metals." Thus, EPA has correctly determined that control technologies will "indiscriminately" capture all 10 HAP metals and that the same control measures will be used for the 8 metal surrogate as would be used for the 10 metals individually. Thus, EPA has ample justification to set a standard for the 8-metal TSM surrogate. Notably, the TSM standard does not undermine the validity of or need for the PM standard for HAP metals. As explained above, the TSM standard will provide a more tailored compliance alternative for units where potential metal HAP emissions are expected to be low and, therefore, PM would be an overly conservative surrogate. However, EPA must gather fuel metals data from the TSM top performers and include a fuel variability factor when setting TSM limits for solid fuel units to ensure full consideration of variability.

Response: The EPA thanks the commenter for their support of using TSM8 as a surrogate for metallic HAP and for setting alternative TSM limits. The EPA has included fuel variability for TSM in the final rule.

Commenter Name: Dean C. DeLorey

Commenter Affiliation: The Amalgamated Sugar Company LLC (TASCO)

Document Control Number: EPA-HQ-OAR-2002-0058-3522-A1

Comment Excerpt Number: 19

Comment: Using TSM as a basis for emission standards is not sensitive to the fact that each of the metals specified in this definition has different hazard and toxicity characteristics. Please clarify how the agency rationalizes setting a standard based upon a "combination" of values. In any given sample if the concentration of one metal is significantly higher than the others, the one metal may skew the results. In fuel analysis data supplied by TASCO vendors, the concentration of manganese is more than one order of magnitude higher than any of the other metals on the TSM list. However, the health hazard of exposure to manganese is significantly less than the other metals (Le. NIOSH limits for Mn are higher than other metals).

Response: In this reconsideration, EPA proposed revisions to certain MACT standards for boilers and process heaters. As such, this action does not address health-based or risk-based standards. In this alternative metals standard, the EPA established an alternative MACT floor emission limit based on the reported sum of eight individual non-Hg metals. Each of these metals are regulated under Section 112 and are targeted pollutants under this source category. Therefore the EPA has determined it has the authority to regulate each of these metals and it is appropriate to establish an emission limit based on the total of these 8 metals as an alternative to the PM emission standards.

6E. TSM Alternative for non-Hg metals (liquid fuels)

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 71

Comment: More importantly than this precedent, however, is that EPA's second concern should not preclude a TSM standard but should only influence what that standard is. Because of the variability identified, EPA should ensure that the alternative TSM standard is set at a level that takes this into consideration. As with all other standards in the proposed reconsideration, EPA has utilized a 99% UPL calculation to capture statistical variability, and compared this calculation to measurement detection level variability as well as a fuel variability determination. These variability determinations have already been calculated, although EPA has refused the results for the proposal, noting that they do not "appear to represent the actual performance of the best performing units." We encourage EPA to appropriately consider the application of variability in defining a TSM alternative for the non-continental liquid subcategory. EPA is afforded wide latitude in defining "achieved in practice", but it should be noted that the D.C. Circuit has enforced that the standard should represent what the best performing sources can "achieve under the worst foreseeable conditions,"³⁰ not what "appears to represent actual performance."

Response: The final rule includes an alternative TSM limit for the liquid fuel subcategories. In setting these alternative limits, the EPA has considered emission, detection level, and fuel variability, as is done for all other pollutants and subcategories. The fuel variability incorporates variability in fuel feedstocks that occur at best performing units during periods not covered by the stack tests. The fuel variability factor compares the fuel constituents (e.g., TSM) during the test with the fuel constituents during other periods of operation in order to evaluate the full range of fuels consumed by these best performing units. The EPA believes that its consideration of variability appropriately establishes standards for which best performing sources can achieve under the worst foreseeable conditions.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 61

Comment: While proposed for all solid fuel subcategories and the Gas 2 subcategory, alternative TSM limits were not proposed for any liquid subcategories.

We believe having alternative limits can be valuable and we encourage EPA to establish such an alternative for all subcategories. EPA currently has adequate data to establish a TSM alternative standard for the liquid subcategories. For example, EPA has TSM emissions tests and/or fuel analyses from 27 sources in the heavy liquid subcategory. The tests and analyses from these 27 sources was of sufficient quality for the Eastern Research Group, Inc. (ERG) to calculate and

suggest to EPA a 99% UPL for a TSM alternative for the heavy liquid subcategory representative of “the average emission limitation achieved by the best performing 12 percent of the existing sources.”²⁰ Furthermore, as noted in the November 2011 MACT Floor memorandum from ERG, even when TSM data was not available directly from sources in the non-continental liquid subcategory, EPA could appropriately calculate the floor “using the top performing tests firing #6 fuel oil since this is the type of liquid fuel reportedly fired at the non-continental refineries.”²¹ As a basis of comparison, EPA identified that a TSM alternative was appropriate for the Gas 2 subcategory based on a 99% UPL of only a single test from a single unit without a corresponding fuel analysis. It is clear that there is sufficient data currently available for EPA to appropriately establish TSM alternatives for the liquid subcategories as well.

Because a TSM alternative is a necessary option to provide sources with flexibility of compliance while still ensuring the maximum pollutant reduction of the HAPs driving the regulation, withholding a TSM alternative would unnecessarily penalize liquid-fired units without offering additional pollution reduction. EPA has recognized the value and appropriateness of the TSM alternative for all other subcategories, and even directly to liquid-fired units under the final Mercury and Air Toxics Standards.

[Footnote 20: Clean Air Act §112(d)(3)(A)..]

[Footnote 21:EPA-HQ-OAR-2002-0058-3387, Memo from ERG, Inc. to Brian Shrager, “Revised MACT Floor Analysis (November 2011) for the Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants – Major Source”, November 2011.]

Response: The EPA agrees with the commenter's claim that there is enough data to establish alternative TSM standards for the liquid fuel subcategories. Alternative TSM standards for those subcategories are included in the final rule.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 89

Comment: We support EPA’s efforts to collect additional data to establish TSM limits for liquid subcategory units. There is no compelling reason to establish TSM limits for solid and gas 2 boilers and not for liquid boilers. If the limited amount of data available makes the MACT floor based on the top 12 percent of units for which data are available unrepresentative of what the true top performing units should be achieving, then EPA could set TSM emission limits based on the top performing units in the PM subcategories. Having an option to comply with a TSM limit is a valuable alternative for liquid units.

Response: The EPA thanks the commenter for their support of alternative TSM emission limitations. In the final rule, the EPA has established a TSM alternative for all fuel subcategories, including liquid fuels. The EPA received sufficient metallic HAP emissions data from units designed to combust liquid fuels during the public comment period to set standards for all subcategories.

Commenter Name: Sarah E. Amick
Commenter Affiliation: Rubber Manufacturers Association (RMA)
Document Control Number: EPA-HQ-OAR-2002-0058-3503-A1
Comment Excerpt Number: 14

Comment: The proposed rule provided a TSM alternative for several subcategories. However, EPA did not set a TSM standard for liquid units as they were unable to draw a correlation between the PM and the TSM floor data. TSM floor data for liquid fired units primarily consists of fuel analysis data while the PM floor data was derived from source test results. RMA recommends that EPA set an alternative TSM limit utilizing the TSM results associated with the best performing units in the PM subcategories.

We support EPA's efforts to collect additional data to establish TSM limits for liquid subcategory units. There is no compelling reason to establish TSM limits for solid and gas 2 boilers and not for liquid boilers. If the limited amount of data available makes the MACT floor based on the top 12 percent of units for which data are available unrepresentative of what the true top performing units should be achieving, then EPA could set TSM emission limits based on the top performing units in the PM subcategories. Having an option to comply with a TSM limit is a valuable alternative for liquid units.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 89.

Commenter Name: Lorraine Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1
Comment Excerpt Number: 5

Comment: *EPA should establish TSM limits for liquid units*

There is no compelling reason to establish TSM limits for solid and gas 2 boilers and not for liquid boilers. EPA's final Mercury and Air Toxics Standards (MATS)² provides a choice between complying with a PM or a TSM standard for liquid electric generating units (EGUs). If EPA is concerned that the limited amount of data available makes the Maximum Achievable Control Technology (MACT) floor based on the top 12 percent of units for which data are available might be unrepresentative of what the true top performing units should be achieving, then EPA could set TSM emission limits based on the top performing units in each of the PM subcategories.

Response: See the responses to comments EPA-HQ-OAR-2002-0058-3521-A1, excerpt 89 and EPA-HQ-OAR-2002-0058-3677-A2, excerpt 61.

Commenter Name: Matthew Todd
Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)
Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2
Comment Excerpt Number: 72

Comment: We urge EPA to define a TSM alternative for the non-continental liquid subcategory that represents what the best performing sources can meet under the worst foreseeable circumstances. For the TSM alternative specifically, which is comprised of a mix of both fuel analyses and emissions tests, it is suggested that EPA rank the top TSM performers based on the best performing sources for filterable PM, as all filterable PM data are directly comparable emissions test results. Based on this ranking for defining a TSM standard alternative for the non-continental liquid subcategory, we support the use of the 99% UPL calculation to define statistical variability of the top performing 12 percent of sources with No. 6 oil TSM data currently available to EPA, which includes No. 6 oil data from continental units (as was calculated by EPA but not incorporated into the proposed rule). As with the other standards, the 99% UPL should then be compared to the variability in the fuel, as well as the method detection level, with the maximum value chosen as the TSM alternative standard.

Response: See the responses to comments EPA-HQ-OAR-2002-0058-3521-A1, excerpt 89 and EPA-HQ-OAR-2002-0058-3677-A2, excerpt 71 for discussion. The TSM MACT floor limit for the non-continental liquid subcategory was based solely on TSM data received on 8 non-continental units.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 69

Comment: EPA should establish an alternative TSM limit for the continental and non-continental liquids subcategories.

EPA specifically requested sufficient information to support the TSM alternative standard for all liquid subcategories as noted in 76 FR 80606 and quoted in Comment II.4.C above, noting that the TSM alternative was not included in the proposal because of 1) the limited emissions test data, and 2) the large variability in TSM data. The sufficiency of the TSM data has been discussed previously.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 61.

Commenter Name: Lisa Barry

Commenter Affiliation: Chevron Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3687-A2

Comment Excerpt Number: 4

Comment: We understand that EPA is hesitant to provide an alternative TSM limit for liquid units since EPA's variability tool on the small metal data set for liquid units gives a TSM limit that seems high to EPA and not representative of the best performing 12% of units. Since EPA requested more metals data, API/AFPM did provide in their comments today additional liquid fuel metals data that may help EPA be more comfortable with the variability tool's results. However, we note that EPA already has metals data for 27 heavy liquid units nationwide, and EPA set a TSM limit for gas2 units using data from only a single unit. We believe that for

equitable treatment across fuel types EPA must establish an alternative TSM limit for liquid units. Also, the final NESHAP for island electric generating liquid units has an alternative TSM limit, and it would seem fair and logical for liquid units in other industrial sectors to also have a TSM alternative.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 61.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 70

Comment: As per EPA's second concern, similar variability can be observed for the fluidized bed coal boilers, which do have a TSM alternative. The ratio between the statistical variability calculated using the 99% UPL and the fuel variability for heavy liquid, non-continental liquid, and fluidized bed coal boilers is similar in each case. As well, the maximum ratio of TSM in the fuel samples for fluidized bed coal boilers is 1.14, which compares closely to the maximum ratio for heavy liquid and non-continental of 1.13. Because the TSM alternative was deemed appropriate for fluidized bed coal boilers with similar TSM variability to heavy liquid and non-continental units, it is only appropriate to establish TSM alternative standards for these subcategories as well.

Response: The EPA agrees with the commenter that the inherent variability in reported TSM emissions from fluidized bed coal combustors is similar to that of reported TSM data for liquid fuel combustors. The EPA has included an alternative TSM standard for the liquid fuel subcategories in the final rule.

Commenter Name: Michael L. Krancer

Commenter Affiliation: Pennsylvania Department of Environmental Protection (DEP)

Document Control Number: EPA-HQ-OAR-2002-0058-3507-A1

Comment Excerpt Number: 2

Comment: The EPA did not propose alternative TSM limits for the liquid fuel subcategories because of limited emission test data and the large variability in the TSM data in these subcategories. The EPA is soliciting comment on whether alternative TSM limits are appropriate for the subcategories of units designed to burn liquid fuels, and on whether an alternative approach to calculating the TSM MACT floors for these units is appropriate.

The DEP is in favor of providing alternative TSM limits for units that burn liquid fuels provide adequate data exists for the establishment of such limits.

Response: The EPA received additional TSM data from liquid units, and now has sufficient data exists to set alternative TSM standards for the liquid fuel subcategories. Alternative TSM standards for the liquid fuel subcategories have been added to the final rule.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1
Comment Excerpt Number: 43

Comment: EPA did not provide a TSM option for liquid fuels. "For the light liquid, heavy liquid and non-continental liquid units subcategories, we are not proposing alternative TSM emission limits. Instead, we are proposing that these units meet the filterable PM emission limits in all instances." 76 Fed. Reg. 80,606. EPA determined that the emission data were too limited for TSM in this subcategory, but added that if it receives sufficient data indicating that TSM is appropriate, it would consider adopting a TSM option for liquid fuels as well. *Id.*

CIBO supports EPA's efforts to gather additional data to evaluate the possibility of a TSM option for liquid fuels. However, based on the analysis and conclusion EPA reached for solid fuel fired units, CIBO would expect that liquid fired units would lead to the same conclusions, based on logical conclusions with respect to these fuels and their typical emissions characteristics.

Response: For a response to the claim that the EPA should collect additional data and set alternative TSM standards for the liquid fuel subcategories, please see comment EPA-HQ-OAR-2002-0058-3507-A1, excerpt 2. The EPA acknowledges the commenter's opinion that sources burning liquid fuel would likely choose compliance with the PM standard, even if a TSM alternative is established.

Commenter Name: David L. Meeker
Commenter Affiliation: National Renderers Association (NRA)
Document Control Number: EPA-HQ-OAR-2002-0058-3476-A1
Comment Excerpt Number: 14

Comment: EPA issued the *National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-Fired Electric Utility Steam Generating Units* (NESHAP Subpart UUUUU) and *Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional Steam Generating Units* (modifications to NSPS Subparts D, Da, Db, and Dc) rules on December 16, 2011. NESHAP Subpart UUUUU is not applicable to boilers and process heaters at NRA member facilities since the units are not utilized to produce steam for electricity generating purposes above the thresholds defined in the rule. However, the proposed rule is relevant to this discussion concerning how EPA established emission standards for metal HAPs. In both the Boiler MACT and NESHAP Subpart UUUUU, EPA defined PM (filterable content) as an appropriate surrogate for metal HAP emissions.

The justification for using PM emissions as a surrogate pollutant for non-mercury metal HAP emissions in NESHAP Subpart UUUUU is the same DC Circuit Court determination used for the justification in NESHAP Subpart DDDDD. Electric generating units (EGUs) subject to NESHAP Subpart UUUUU will have the option to demonstrate compliance with the nonmercury metal HAP surrogate (PM) emissions limitation, the total selected metals (TSM) emissions limitation, or the individual non-mercury metal HAP emissions limitation(s). The reconsidered Boiler MACT, NESHAP Subpart DDDDD includes TSM or individual nonmercury metal HAP

emissions limitation(s) as an alternative to the metal HAP surrogate (PM) for the solid fuels (solid fossil fuels or biomass) only. The alternative compliance option is not provided for liquid fuel (light or heavy) fired units.

The NRA is not addressing in this comment letter whether PM is an appropriate surrogate option for non-mercury metal HAP from liquid fuel combustion. Instead, the NRA is bringing to EPA's attention that by not providing an option for direct measurement of TSM or individual nonmercury metal HAP content where it is feasible, EPA is detaching the rule from the underlying statutory requirements for control of HAP (of which PM is not). The NRA requests that EPA finds it is appropriate to include an option to demonstrate compliance directly with a TSM or individual non-mercury metal HAP emissions limitation(s) via fuel sampling for liquid fuels for NESHAP Subpart DDDDD. This comment is specifically for the NRA members and customers that will utilize a liquid fuel, not processed fats, as a back-up fuel source for boilers subject to NESHAP subpart DDDDD.

Response: The EPA is adopting a TSM alternative limit for the liquid fuel subcategories.

Commenter Name: Mary Sullivan Douglas

Commenter Affiliation: National Association of Clean Air Agencies (NACAA)

Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1

Comment Excerpt Number: 60

Comment: EPA has not proposed a TSM alternative "because of the limited emission test data for TSM and the large variability in the TSM data for these subcategories. Using the EPA's maximum achievable control technology (MACT) floor methodology, the alternative TSM limits resulted in MACT floor values which do not appear to represent the actual performance of the best performing units." NACAA agrees with EPA's recommendation and the rationale for not proposing such limits. While EPA has sent follow-on inquiries to some sources for additional data, there is insufficient opportunity to meaningfully review and comment on any data that may be provided at this time.

Response: In the final rule, the EPA has established a TSM alternative for all fuel subcategories, including liquid fuels. The EPA received metallic HAP emissions data from units designed to combust liquid fuels during the public comment period. Enough data were available to set standards for all subcategories using the same MACT floor methodology as used for establishing TSM emission limits for the other subcategories. Moreover, EPA disagrees that the public did not have a meaningful opportunity to comment on alternative TSM limits. EPA clearly described its approach for establishing such limits in the proposed reconsideration and

solicited data to set such limits. Therefore, members of the public could comment on the appropriateness of alternative TSM limits as well as on the amount and type of data that should be used to set such limits. The fact that data was received during the comment period does not warrant further opportunity for public comment. To do so would potentially result in an endless loop of notice and comment that would delay final action.

Commenter Name: Michael Bradley
Commenter Affiliation: The Clean Energy Group
Document Control Number: EPA-HQ-OAR-2002-0058-3495-A1
Comment Excerpt Number: 9

Comment: As an alternative to the PM limits in the final rule, EPA proposes to allow compliance with an emission limit for total selected metals (TSM). Under this option, units combusting solid or Gas 2 fuels could opt to comply with a TSM limit, which would directly measure emissions of arsenic, beryllium, cadmium, chromium, lead, manganese, nickel, and selenium. This is a reasonable option, particularly for biomass units, for example, which may have PM emissions with lower HAP concentrations. EPA requests comment on whether the alternative should apply to liquid fuels. The Clean Energy Group sees no reason this compliance demonstration alternative should not apply to liquid-fueled units as well, although we expect that the majority of operators will choose the simpler PM tests.

Response: The EPA acknowledges this comment.

Commenter Name: Heather Parent
Commenter Affiliation: Maine Department of Environmental Protection
Document Control Number: EPA-HQ-OAR-2002-0058-3691-A2
Comment Excerpt Number: 12

Comment: Maine DEP supports the proposed alternative of a total selected metals (TSM) emission standard to the PM emission standard, and we believe this alternative should be provided to both liquid fuels and solid fuels.

Response: The EPA thanks the commenter for their support.

Commenter Name: Dakota Gasification Company Great Plains Synfuels Plant
Commenter Affiliation: David W. Peightal
Document Control Number: EPA-HQ-OAR-2002-0058-3424
Comment Excerpt Number: 1

Comment: DGC supports EPA's determination of allowing for alternative TSM limit, except that EPA failed to include the alternative TSM for heavy liquid subcategory. EPA did include the heavy liquid subcategory in the PM GEMS monitoring requirements as a part of the affected categories. DGC agrees on the variability discussion on mixed fuels since DGC uses a variety of fuels (liquids and gases) recovering the heat value for combustion. As noted in the previous comment submitted by DGC, the GPSP operates boilers that have a Flue Gas Desulfurization Unit (FGD) to control SO₂ emissions. This control technology is considered BACT and works by

using ammonia to scrub the SO₂ from the flue gas forming ammonium sulfate, which is processed for use as a fertilizer. One of the natural functions of this FGD system is the slippage of small amounts of ammonia. This ammonia can combine with remaining low level sulfur in the flue gas to form ammonium sulfate in the atmosphere even after it passes through our Wet Electrostatic Precipitator (WESP). DGC operates FGD where a significant amount of ammonium sulfate particulate is produced and eventually emitted from the stack and by definition is not an HAP. For this reason, PM is not a representative surrogate for metal HAPs for DGC. The WESP works well enough to control emissions so that our most recent stack test shows only 27 lbs/hr of PM₁₀ and 22 lbs/hr filterable PM from the September 2011 test.

DGC should not be penalized for having particulate emissions that are not HAPs and should be allowed to demonstrate compliance with the alternative TSM limit, or to at least allow the use of the alternative TSM limit if it fails the PM emissions limit test. This standard does not seem practical or representative, and needs to be re evaluated. TSM is an option that would provide flexibility to affected sources as an alternative to the PM limit and represents directly the true area of concern. The standard as proposed for existing heavy liquid-fired boilers is not technically achievable for sustainable compliance for our facility configuration.

The use of particulate as a surrogate for metal HAPs at DGC's GPSP in effect results in a more stringent metal HAPs limit for the GPSP. It appears that DGC may not achieve the limit for PM even with the use of BACT such as a WESP on a sustainable basis. Therefore, DGC requests EPA either allow the compliance option (such as alternative TSM limit) in lieu of PM as a surrogate or create another

subcategory, such as wet ammonia scrubber, that will raise the particulate emission limit for units that use an ammonia absorber and WESP for SO₂ and PM control. As DGC mentioned earlier, this control technology is unique, and to DGC's knowledge there is only one other ammonia absorber in operation and that facility is in Canada.

Response: The EPA thanks the commenter for their support of the alternative TSM limits. The EPA has established an alternative TSM standard for all of the liquid fuel subcategories in the final rule. The EPA believes that the addition of the alternative standard for liquids provides the commenter flexibility that may be used to counter the inherent nature of PM emissions at the facility.

6Z. Out of Scope - Rationale for Regulated Pollutants

Commenter Name: Russell A. Wozniak

Commenter Affiliation: The Dow Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3449-A1

Comment Excerpt Number: 9

Comment: Although CO is being used as a surrogate for organic HAP emissions in this case, extremely low CO emission requirements are counterproductive for the overall environment when established without consideration of other requirements such as NO_x minimization or greenhouse gas generation. Conventional NO_x control technologies utilize staggered fuel or air systems that depress the maximum flame temperature thereby reducing thermal NO_x formation.

This same technique can generate CO values due to the staging process. Tuning these burners to reduce CO will increase flame temperatures thereby increasing NOx levels. Manufacturer and technical solutions for management of CO in conjunction with low NOx technology involves increasing the combustion product time at temperature (residence time) in order to completely convert the CO to CO2. Incorporating extended residence times is not possible without extensive modification to the basic structure of the chamber or footprint. For existing installations modifications of this nature are typically not financially feasible. For new installations incorporation of increased residence times involves increased capital investment.

Other means to reduce CO involve higher operating temperatures, involving higher fuel inputs coupled with increased potential operating load. One less than desirable aspect of increased energy rate is the impact on energy efficiency. Operating load is dependent upon the production plan developed for the facility that the boiler or process heater is supporting. If the demand is not there the boiler / process heater cannot increase energy rate without incorporating excess air to manage temperature. This practice will reduce the actual measured CO limit due to the influence of the oxygen correction. A second effect of the higher operating temperature is the increase in CO2 generation along with increased NOx formation.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Robert E. Hunzinger

Commenter Affiliation: Gainesville Regional Utilities (GRU), Florida

Document Control Number: EPA-HQ-OAR-2002-0058-3488-A1

Comment Excerpt Number: 1

Comment: GRU supports EPA's decision to amend the particulate matter (PM) limit from total PM to total filterable PM. The fact that virtually all non-mercury metals of concern are found in the filterable PM fraction provides adequate support for EPA's decision.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 39

Comment: EPA could allow for a petition to the permitting authority for determination of a unit-specific CO emission limit if it is determined that a boiler or process heater cannot attain the final rule CO emission limit without major unit redesign, oxidation catalyst addition with associated stack gas reheat and increased fuel usage, exceedance of an applicable NOx standard, or derating the unit. As EPA has monetized benefits for only PM2.5 and its precursors (NOx and SO2) it is apparent that requiring drastic reductions in CO emissions to the detriment of NOx emissions is not the desired outcome. Further, units close to Class I areas will be sensitive not only to increases in NOx emissions but also to implementation of NOx controls that might result in ammonia slip.

The process of determining a unit-specific CO limit could include:

- performing a tune-up according to a standard industry protocol (e.g., ASME PTC 4-2008, Fired Steam Generators, which provides rules and instructions for conducting performance tests of fuel fired steam generators)
- inspection and maintenance of the boiler/process heater and its fuel supply system to ensure they are in good operating condition,
- testing for CO emissions over the range of operating conditions to determine a site- specific CO limit and appropriate operating parameter limits, and
- establishment of a protocol for ongoing unit operation to ensure good combustion practices.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

102A. PM as a Surrogate for Non-Mercury Metallic HAP [DENIED PETITIONER ISSUE]

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 7

Comment: EPA's use of surrogates continues to be unlawful and arbitrary for all the reasons given in the 2010 Comments, which are incorporated by reference as if fully stated herein and reiterated with respect to the agency's 2011 final rule and reconsideration proposal. 2010 Comments at 8-20. In addition, EPA has now finalized a definition of solid waste (and has proposed another on reconsideration) that excludes a wide variety of discarded materials including tires, sludges, spent solvent, scrap plastics, and the like. As a result of this definition, sources burning these materials would be regulated, if at all, under EPA's boilers rule. The emissions of metals from units burning secondary materials with relatively high metals emissions will be correlated less (if at all) with their emissions of PM. That is, emissions of metals (e.g. lead) could increase or decrease, without a corresponding increase or decrease in PM emissions, as a result of the materials such a source chooses to burn. For this reason as well as those given in the 2010 Comments, control of PM emissions is not the only means by which sources in the boilers category achieve lower emissions of metals such as lead, chromium and arsenic. Rather, some sources in the category achieve lower emission levels for these pollutants by choosing not to burn materials containing higher levels of these metals. For example, some sources choose not to burn whole tires or spent solvents or discarded oils that contain metals, and therefore have lower emissions of lead, chromium, arsenic and other metals. Because EPA has chosen to regulate waste burning sources as part of the boilers category rather than as incinerators, the variability of sources' metals emissions will increase or decrease for reasons unrelated to their PM control. Accordingly, for this category, PM fails the test as a surrogate for these metals.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 9

Comment: In its final rule, EPA proffered a new rationale for its use of PM as a surrogate for non-mercury metals, that "[t]he partitioning of the metal HAPs is very complicated and can depend upon the fuel type, the form of metals in the fuel, other constituents in the fuel and the time- temperature profile of the post-combustion environment." Response to Comments Vol. 2 at 3187.1 cmt. That variations in "fuel type, the form of metals in the fuel, other constituents in the fuel and the time-temperature profile of the post-combustion environment" affect the partitioning of specific metal HAPs does not support the use of PM as a surrogate for these HAPs. To the contrary, it confirms the lack of a linear relationship between total particulate matter and hazardous air pollution – and further supports the insufficiency of total particulate matter as a surrogate.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 10

Comment: EPA indicated – without further support – that "EPA's Office of Research and Development has conducted studies that showed that good control of the non-Hg metal HAP followed good control of bulk PM (filterable) across the primary PM control device." *Id.* Those studies are not, to our knowledge, in the record, and thus do not suffice to justify the Agency's decision (nor can the public meaningfully comment). Moreover, even if true, that general "following" of non-Hg metal control behind good particulate matter (filterable) control does not allow the Agency to substitute filterable particulate matter controls for direct controls on specific HAP; it does not, in particular, demonstrate the absence of other methods of limiting non-Hg HAP (in particular, fuel-switching) nor does it demonstrate the necessary fixed relationship between particulate matter control and control of non-Hg metallic pollutants.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 87

Comment: We understand and do not challenge EPA's approach to using particulate matter as a surrogate for non-mercury metallic HAP since metals are a component of particulate matter from

boilers and testing for PM is simpler than testing for total metals. We do not wish to eliminate the use of PM as a compliance option.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

102B. CO as a Surrogate for Organic HAP [DENIED PETITIONER ISSUE]

Commenter Name: Claudia M. O'Brien, Latham & Watkins LLP

Commenter Affiliation: JELD-WEN, inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3485-A1

Comment Excerpt Number: 9

Comment: EPA may only use surrogates to regulate HAPs "if it is *reasonable* to so do."²⁸ Among other factors for determining whether using a surrogate is reasonable, courts look to whether the agency has demonstrated a correlation between the HAP and the surrogate.²⁹ While it is still unsettled in law whether an agency is required to specifically quantify the correlation or assess its variability,³⁰ that does not matter here because EPA made only general statements regarding correlation, and any assumption that there is a valid correlation between CO and non dioxin/furan organic HAP in industrial boilers has been refuted by EPA's subsequent findings on correlation in its Utility MACT proposal.

In its Boiler MACT proposal, in which EPA first proposed the CO emissions standard as a means of regulating non-dioxin/furan organic HAP, EPA noted that CO "has *generally* been used as a surrogate for organic HAP because CO is a good indicator of incomplete combustion and organic HAP are products of incomplete combustion," and that its use as a surrogate "is a reasonable approach because minimizing CO emissions will result in minimizing non-dioxin organic HAP."³¹ Despite these and other general statements about why CO is an appropriate surrogate for non-dioxin/furan organic HAP, EPA did not reference any data supporting the correlation and EPA has not addressed this issue in the Boiler MACT reconsideration.

[Footnote 28: *Mossville Environmental Action Now v. EPA*, 370 F.3d 1232, 1242 (D.C. Cir. 2004) (citation omitted) (emphasis added).]

[Footnote 29: See *Mossville Environmental Action Now v. EPA*, 370 F.3d 1232, 1242 (D.C. Cir. 2004) (citation omitted) (emphasis added).]

[Footnote 30: See *Mossville Environmental Action Now v. EPA*, 370 F.3d 1232, 1242 (D.C. Cir. 2004) (citation omitted) (emphasis added).]

[Footnote 31: 75 Fed. Reg. 32,006,32,018 (June 4, 2010) (Proposed Rule).]

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Claudia M. O'Brien, Latham & Watkins LLP

Commenter Affiliation: JELD-WEN, inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3485-A1

Comment Excerpt Number: 10

Comment: In contrast, EPA required testing to be conducted to examine potential surrogacy relationships for its Utility MACT proposal.³² EPA selected 170 units and required them to test for CO, volatile organic compounds (VOC), and total hydrocarbons (THC).³³ EPA acknowledged in its Utility MACT proposal that emissions of CO, VOC, and/or THC "have, in the past, been used as surrogates for the non-dioxin/furan organic HAP based on the theory that efficient combustion leads to lower organic emissions" (specifically citing the Boiler MACT proposal among others)³⁴ and stated that "[b]ecause CO and organics are both products of poor combustion, it is logical to expect that limiting the concentration of CO would also limit the production of organics."³⁵ However, despite this "logic," EPA found that "it is very difficult to develop direct correlations between the average concentration of CO and the amount of organics produced during the prescribed sampling period...."³⁶ Thus, after evaluating the data from the testing it required, EPA concluded that "it was difficult to correlate that concentration [of CO] to the quantity of organics produced...." and cited several reasons including the large number of potential organics that can be produced, the fact that they tended to be at or below the MDL in the same samples, and the fact that there were complications associated with the CO concentration values.³⁷ Because EPA considered it "impracticable to reliably measure emissions," EPA proposed a work practice standard for non-dioxin/furan organic HAP.³⁸

[Footnote 32: 76 Fed. Reg. at 25,024, 25,039.]

[Footnote 33: 76 Fed. Reg. at 25,039.] [Footnote 34: 76 Fed. Reg. at 25,024.] [Footnote 35: 76 Fed. Reg. at 25,039.]

[Footnote 36: 76 Fed. Reg. at 25,039.]

[Footnote 37: 76 Fed. Reg. at 25,039.]

[Footnote 38: 76 Fed. Reg. at 25,042.]

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 8

Comment: Sources' emissions of organic pollutants such as polychlorinated biphenyls (PCBs) and polycyclic organic matter (POM) will be correlated less (if at all) with their emissions of carbon monoxide, EPA's chosen surrogate for non-dioxins organic pollutants. Specifically, emissions of these pollutants could increase and decrease without a corresponding increase or decrease in CO emissions as a result of whether sources choose to burn tires, solvents, plastics, and the like. For this reason as well as those given in the 2010 Comments, control of CO emissions is not the only means by which sources in the boilers category achieve lower

emissions of organic pollutants including PCBs and POM. Accordingly, CO is not a valid surrogate for PCBs, POM and the other organic hazardous air pollutants that boilers emit.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

102C. Work Practice for Organic HAP [DENIED PETITIONER ISSUE]

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 50

Comment: In the recently-promulgated MATS rule, EPA established work practice standards for organic HAP emissions because "the majority of emissions of these pollutants are below the detection levels of EPA test methods and, therefore, are impractical to measure." 77 Fed. Reg. 9304, 9380 (Feb. 16, 2012). In testing of coal-fired boilers conducted in support of the Utility MACT, EPA found that "organic compounds tend[ed] to be at or below the MDL in coal combustion flue gas samples" even when CO was measured in the flue gas at levels of 23 to 137 ppm. 76 Fed. Reg. 24976, 25039 (May 3, 2011). In other words, even though valid CO measurements were available for coal-fired boilers, EPA determined that a work practice standard for volatile HAPs was appropriate and justified because at the levels of CO measured during testing, the corresponding amount of HAP emissions was below levels that reliably could be measured.

The same rationale supports a determination that work practice standards are appropriate and justified for coal-fired industrial boilers. While the amount of emissions testing for individual volatile HAPs is limited for coal-fired industrial boilers, EPA has good reason to conclude that the general relationship between CO emissions and volatile HAP emissions in the flue gas from industrial boilers should be the same as the relationship established in the testing conducted in support of the Utility MACT. For example, the same basic furnace designs are used in industrial boilers as are used in utility boilers. Moreover, it goes without saying that the same combustion chemistry and dynamics occur in industrial boilers as in utility boilers. In addition, operators of industrial coal-fired boilers purchase coal from the same markets as operators of utility boilers. In fact, the biggest overall differences between industrial boilers and utility boilers are size (with utility boilers generally being bigger than industrial boilers) and utilization (with industrial boilers typically having more variable loads and utilization). But, these differences should not be expected to cause the general relationship between CO emissions and volatile HAP emissions to be significantly different for fossil fuel-fired industrial boilers as compared to fossil fuel-fired utility boilers.

In short, at the relatively low CO levels measured in the flue gas from the best performing fossil fuel-fired industrial boilers, EPA can reasonably expect that the corresponding levels of volatile HAPs will be so low as to not be reliably measureable. This provides ample justification for setting work practice standards for volatile HAP emissions from fossil fuel-fired industrial boilers.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 34

Comment: EPA hired a contractor to conduct an extensive pilot study to truly determine the expected emission profiles and relationship of non-dioxin organic HAP and CO for coal-fired units. This test program included a variety of types of coal and is titled "Surrogacy Testing in the Multi-Pollutant Research Control Facility", dated March 30, 2011. The excerpt from the preamble to the proposed MATS rule where EPA articulates its rationale for work practice standards in lieu of CO limits for coal-fired utility boilers is shown below.

"Tests were also conducted to examine potential surrogacy relationships for the non-dioxin/furan organic HAP. The amounts of Hg, non-Hg metals, HCl, HF, and Cl₂ in the flue gas are directly related to the amounts of Hg, non-Hg metals, chlorine, and fluorine in the coal. Control of these components generally requires downstream control technology. However, the presence of the organics in the flue gas is not related to the composition of the fuel but rather they are a result of incomplete or poor combustion. Control of the organics is often achieved by improving combustion conditions to minimize formation or to maximize destruction of the organics in the combustion environment.

During the pilot-scale tests, sampling was conducted for semi-volatile and volatile organic HAP and aldehydes. On-line monitors also collected data on THC, CO, O₂, and other processing conditions. Total hydrocarbons and CO have been used previously as surrogates for the presence of non-dioxin/furan organics. Carbon monoxide has often been used as an indicator of combustion conditions. Under conditions of ideal combustion, a carbon-based or hydrocarbon fuel will completely oxidize to produce only CO₂ and water. Under conditions of incomplete or non-ideal combustion, a greater amount of CO will be formed.

With complex carbon-based fuels, combustion is rarely ideal and some CO and concomitant organic compounds are expected to be formed. Because CO and organics are both products of poor combustion, it is logical to expect that limiting the concentration of CO would also limit the production of organics. However, it is very difficult to develop direct correlations between the average concentration of CO and the amount of organics produced during the prescribed sampling period in the MPCRF (which was 4 hours for the pilot-scale tests described here). This is especially true for low values of CO as one would expect corresponding low quantities of organics to be produced. Samples of coal combustion flue gas have mostly shown very low quantities of the organic compounds of interest. Some of the flue gas organics may also be destroyed in the high temperature post combustion zone (whereas the CO would remain stable). Semi-volatile organics may also condense on PM and be removed in the PM control device.

The average CO from the pilot-scale tests ranged from 23 to 137 ppm for the bituminous coals tests, from 43 to 48 ppm for the subbituminous coal tests and from 93 to 129 ppm for the Gulf Coast lignite tests. However, it was difficult to correlate that concentration to the quantity of

organics produced for several reasons. The most difficult problems are associated with the large number of potential organics that can be produced (both those on the HAP list and those that are not on the HAP list). This is further complicated by the organic compounds tending to be at or below the MDL in coal combustion flue gas samples. Further, there are complications associated with the CO concentration values. Some of the runs with very similar average concentrations of CO had very different maximum concentrations of CO (i.e., some of the runs had much more stable emissions of CO whereas others had some excursions, or "spikes," in CO concentration). For example, one of the bituminous runs had an average CO concentration of 69 ppm but a maximum concentration of 1,260 ppm (due to a single "spike" of CO during a short upset). Comparatively, another bituminous run had a higher average CO concentration at 137 ppm but a much lower maximum CO value at 360 ppm.

In the pilot tests, the THC measurement was inadequate as the detection limit of the instrument was much too high to detect changes in the very low concentrations of hydrocarbons in the flue gas.

EPA is proposing work practice standards for non-dioxin/furan organic and dioxin/furan organic HAP. The significant majority of measured emissions from EGUs of these HAP were below the detection levels of the EPA test methods, and, as such, EPA considers it impracticable to reliably measure emissions from these units. As the majority of measurements are so low, doubt is cast on the true levels of emissions that were measured during the tests.For the non-dioxin/furan organic HAP, for the individual HAP or constituent, between 57 and 89 percent of the run data were comprised of values below the detection level. Overall, the available test methods are technically challenged, to the point of providing results that are questionable for all of the organic HAP. For example, for the 2010 ICR testing, EPA extended the sampling time to 8 hours in an attempt to obtain data above the MDL. However, even with this extended sampling time, such data were not obtained making it questionable that any amount of effort, and, thus, expense, would make the tests viable. Based on the difficulties with accurate measurements at the levels of organic HAP encountered from EGUs and the economics associated with units trying to apply measurement methodology to test for compliance with numerical limits, we are proposing a work practice standard under CAA section 112(h)." 76 Fed. Reg. 25039

This study is as applicable to industrial boilers as it is to utility boilers. The EPA testing appears to support this conclusion since no correlations could be made at low CO emission levels associated with normal operation. This is further justification for not requiring ultra-low CO limits for coal-fired boilers in the industrial Boiler MACT, such as the 41 ppm limit proposed for existing pulverized coal boilers, the 56 ppm limit proposed for existing fluidized bed boilers, and the even lower CO limits proposed for new coal-fired units. These are prime examples of MACT limits the manufacturers have told our members they cannot guarantee. Real impacts on organic HAP emissions are not achieved by pressing ultra-low CO limits on fossil fuel combustion units compared to normal operating levels, but higher emissions of organic HAP might only occur with high levels of CO associated with malfunctions, equipment failures, or fuel interruptions. Therefore, while EPA can calculate a MACT Floor CO emission limit for the industrial boilers and process heaters as proposed, there is no defensible driver to impose such low emission limits, and modifying the floor setting procedure or allowing alternatives to accommodate higher allowable emission rates appears justified.

Mandating a work practice standard instead of an emission limit gets more to the core of the MACT rule: minimizing emissions while ensuring efficient operation. As such, CIBO requests EPA consider replacing the numerical CO emission limit in repropose Boiler MACT with a work practice standard similar to the approach used in the Utility MACT (77 FR 9369, February 16, 2012). In the preamble, EPA discusses their belief that "...the work practice standard will result in actions being taken that will reduce the emissions of these (organic) HAP."

However, if EPA continues to pursue imposition of CO limits on ICI boilers and process heaters, in addition to the proposed adjustments to the CO emissions limitations and the proposed alternative CO emissions limitations for units with CEMS, EPA should consider additional alternative approaches to setting standards for CO.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Melvin E. Keener

Commenter Affiliation: Coalition for Responsible Waste Incineration (CRWI)

Document Control Number: EPA-HQ-OAR-2002-0058-3454-A1

Comment Excerpt Number: 4

Comment: EPA should set a work practice standard for organic HAPS for coal-fired boilers.

In the "Utility MACT" final rule (77 Fed. Reg. 9,304, February 16, 2012), EPA concluded that numerical emission standards for organic HAPs were not justified and, instead, set work practice standards. This decision was made because the majority of data for measuring organic HAP emissions were below the detection limit even when long duration tests were used. 77 Fed. Reg. at 9,369. As such, the Agency concluded this allowed the use of a work practice standard under section 112(h) of the Clean Air Act.

CRWI supports that decision and suggests that the same set of facts applies to the coal-fired boilers in this proposed rule. Coal-fired industrial boilers are similar in design, construction, and operation to coal-fired boilers used to generate electricity. Coal-fired boilers under both rule produce steam as their initial product. For the electric generation units, that steam is used to produce electricity. For industrial boilers, the steam is also used to produce electricity but can also be directly used in the production process, to heat buildings, to provide temperature control for the production processes, etc. Essentially, these two sets of coal-fired boilers are similar, just categorized differently based on their use of steam. If the Agency decided that it was inappropriate to set numerical limits for coal-fired boilers used to generate electricity, it also seems that it is inappropriate to set numerical emission standards for organic HAPs for coal-fired industrial boilers. CRWI urges EPA to set work practice standards for organic HAPs similar to what was promulgated in the "Utility MACT" final rule.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Claudia M. O'Brien, Latham & Watkins LLP

Commenter Affiliation: JELD-WEN, inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3485-A1

Comment Excerpt Number: 8

Comment: EPA has chosen to use CO as a surrogate for non-dioxin/furan organic HAP, and in EPA's Boiler MACT reconsideration, it proposes revised CO limits for sources in the non continental liquid unit subcategory²⁶ and to offer CO CEMS-based alternative emission limits and monitoring as an alternative to CO stack testing. However, these proposed modifications do not address the more fundamental problem with EPA's CO numeric emission limits-the problems associated with using CO as a surrogate, which EPA has recognized in its Utility MACT rule. Thus, JELD-WEN urges EPA to revise its reconsideration proposal to repeal the CO emission standard and, instead, establish work practice standards for non-dioxin/furan organic HAP.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Claudia M. O'Brien, Latham & Watkins LLP

Commenter Affiliation: JELD-WEN, inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3485-A1

Comment Excerpt Number: 11

Comment: It appears that EPA did not even attempt to collect data from industrial boilers to establish a correlation between organic HAP and CO levels to support the Boiler MACT rule. However, if it had done so, it almost certainly would have found the exact same problems in making the correlation as it did in the Utility MACT context. The Utility MACT data on CO and the organic HAPs expected to be present in utility flue gas is the most comparable data set to industrial boilers because industrial boilers are generally similar in design and operation to utility boilers, albeit much smaller and with more variable loads. Yet the utility data set did not show a strong enough correlation to support the surrogacy standard applied by the courts. The absence of a reasonable correlation between CO and non-dioxin/furan organic HAPs in the Utility MACT dataset- and the complete absence of any data showing a correlation in the Boiler MACT dataset- leaves EPA with no viable basis on which to use CO as a surrogate here. In the Utility MACT proposal, EPA has concluded, based upon data and calculations, that a work practice standard is appropriate due to the impracticability of reliably measuring non-dioxin/furan organic HAP through CO emissions. So too here, a work practice standard is supported under the legal standard discussed *supra* in section A.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Eric Guelker, Alliant Energy Corporate Services, Inc.

Commenter Affiliation: Interstate Power and Light Company (IPL) and Wisconsin Power and Light Company (WPL), Alliant Energy Corp.

Document Control Number: EPA-HQ-OAR-2002-0058-3492-A1

Comment Excerpt Number: 2

Comment: Alliant Energy believes that this could be extended to other organic HAPs (similar to the final MATS) and thereby, completely eliminate all carbon monoxide (CO) emissions

limitations for all regulated emissions units. For MATs, the EPA concluded that work practices were appropriate, because the significant majority of measured data for organic HAPs were below detection levels of EPA test methods. Alliant Energy believes that this is also the case for smaller boilers and heaters, thus recommends EPA review the organic HAP data for these units to assure equitable treatment in this MACT evaluation. In particular, this is especially true for small house heating boilers with a nameplate capacity less than 100 mmBtu/hr.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Lee Zeugin and Lauren Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1

Comment Excerpt Number: 3

Comment: EPA should extend the work practice standards it has proposed for dioxin and furan emissions to all organic HAPs emitted by IB units. To the extent organic HAP emissions from these units even exist, they result from incomplete combustion - just as in the case of any dioxin or furan emissions. As noted above, the economic incentives for efficient boiler operations will minimize the creation of incomplete combustion products. There is no reason for EPA to treat organic HAP emissions differently than dioxin emissions; work practice standards should be established for both pollutant groups.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Allison Watkins, Baker Botts

Commenter Affiliation: Class of '85 Regulatory Response Group

Document Control Number: EPA-HQ-OAR-2002-0058-3608-A1

Comment Excerpt Number: 7

Comment: EPA should eliminate the carbon monoxide (“CO”) emission limit established by the Major Source Rule⁹ and instead institute a work practice standard for organic HAPs. EPA adopted this approach in the final MATS, and the same rationale supports the adoption of work practice standards here. In the MATS, EPA determined that a work practice standard is appropriate for organic HAPs because a significant majority of data for measured organic HAP emissions from electric generating units (“EGUs”) are below the detection levels of EPA’s test methods.¹⁰ The Group believes that if organic HAP emissions from EGUs are below detection levels, then it is very likely that organic HAP emissions from boilers and process heaters at major sources also are below detection levels. In fact, at least one test run used to calculate the upper prediction limit for CO in the Major Source Rule was reported as non-detect data.¹¹ EPA should ensure that it is consistent in its treatment of detectable emissions levels across rulemakings. Accordingly, the Group urges EPA to consider whether organic HAP emissions can be practicably measured, and if not, EPA should instead institute a work practice standard.

[Footnote 10: *See* 77 Fed. Reg. at 9369.]

[Footnote 11: *See* EPA-HQ-OAR-2002-0058-3273 at 20.]

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Randal G. Oswald

Commenter Affiliation: Integrys Energy Group

Document Control Number: EPA-HQ-OAR-2002-0058-3659-A2

Comment Excerpt Number: 7

Comment: EPA should eliminate the CO emission limit established by the Major Source Rule⁶ and instead institute a work practice standard for organic HAPs. EPA adopted this approach in the final Mercury and Air Toxics Standards for Utilities ("MATS"), and the same rationale supports the adoption of work practice standards here. In the MATS, EPA determined that a work practice standard is appropriate for organic HAPs because a significant majority of data for measured organic HAP emissions from electric generating units ("EGUs") are below the detection levels of EPA's test methods.⁷ We believe that if organic HAP emissions from EGUs are below detection levels, then it is very likely that organic HAP emissions from boilers and process heaters at major sources also are below detection levels. In fact, at least one test run used to calculate the upper prediction limit for CO in the Major Source Rule was reported as non-detect data.⁸ EPA should ensure that it is consistent in its treatment of detectable emissions levels across rulemakings. Accordingly, we urge EPA to consider whether organic HAP emissions can be practicably measured, and if not, EPA should instead institute a work practice standard.

[Footnotes]

(6) CO is a surrogate for organic hazardous air pollutants ("HAPs").

(7) *See* 77 Fed. Reg. at 9369.

(8) *See* EPA-HQ-OAR-2002-0058-3273 at 20.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Robin Mills Ridgway

Commenter Affiliation: Purdue University

Document Control Number: EPA-HQ-OAR-2002-0058-3668-A2

Comment Excerpt Number: 9

Comment: Purdue agrees that CO is an appropriate surrogate for organic HAP. Carbon monoxide is the most common product of incomplete combustion (PIC), and because of its associated chemical kinetics, is one of the most difficult PICs to oxidize completely. As such, CO emissions have historically been used as an indicator of the quality of the combustion process. The concept is that low CO emissions equate to low emissions of other organic compounds.

While this is true in general, the mechanisms by which CO is formed and destroyed in the combustion process are different than for other organics. As such, in cases where other organic compounds have been completely oxidized, CO concentrations may still be elevated. While the tendency is to think that further reductions in CO emissions will improve the quality of the combustion, and in turn minimize emissions of other organic compounds, this is not necessarily true. Instead, forcing CO emissions lower and lower ends up over-constraining the combustion process, resulting in other air quality concerns and loss of unit efficiency, without achieving corresponding reductions in emissions of organics.

Mandating a work practice standard instead of a CO emission limit gets more to the core of the MACT rule: minimizing emissions while ensuring efficient operation. As such, Purdue requests EPA consider replacing the numerical CO emission limit in repropoed Boiler MACT with a work practice standard similar to the approach used in the Utility MACT (77 FR 9369, February 16, 2012). In the preamble, EPA discusses their belief that "...the work practice standard will result in actions being taken that will reduce the emissions of these (organic) HAP."

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Steve Gossett

Commenter Affiliation: Eastman Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3669-A2

Comment Excerpt Number: 2

Comment: In the case of the Utility MACT, EPA went to the expense to hire a contractor to conduct an extensive pilot study to truly determine the expected emission profiles and relationship of non-dioxin organic HAP and CO. This test program included a variety of types of coal and is titled "Surrogacy Testing in the Multi-Pollutant Research Control Facility". The report of the results of this study is dated March 30, 2011. The excerpt from the preamble to the Utility MACT proposed rule where EPA articulates its rationale for work practice standards is shown below. It stands in stark contrast to the rationale shown above for industrial boilers.

Federal Register Page 25039, May 3, 2011

This study is equally applicable to industrial and institutional coal boilers as it is to utility boilers. Many industrial and institutional boilers, including one or more of Eastman's boilers, will make capital investments or de-tune their boilers to reduce CO at the expense of higher year-round NOx emissions to comply with the repropoed standards applicable to coal-fired boilers that utility boilers will not be required to make.

Therefore, as part of its reconsideration process, we request EPA change the rule to eliminate numerical emission standards for CO for coal-fired boiler subcategories and instead refer to the work practice standards. A requirement to conduct periodic tune-ups that optimize CO emissions, inspect and clean/replace burners, adjust flame patterns, and check the air/fuel ratio control system will be more than adequate to ensure proper operation of the boiler and minimize emissions of organic HAP.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Robert Ellerhorst

Commenter Affiliation: Michigan State University

Document Control Number: EPA-HQ-OAR-2002-0058-3674-A2

Comment Excerpt Number: 1

Comment: U.S. EPA is proposing separate carbon monoxide (CO) limits for each boiler subcategory (pulverized coal units, coal-fired CFB, etc). CO is used as a surrogate for non-dioxin/furan organic hazardous air pollutants (HAPs), and therefore it is assumed that all non-dioxin/furan organic HAPs will be represented by CO emissions. These proposed limits must be met during various load conditions and exclude periods of startup and shutdown. CO is a byproduct of incomplete combustion; the average concentration can have very different maximum values (i.e. values can remain stable and can suddenly "spike") and can vary significantly over any given time period. Spikes can be caused by sudden external temperature changes and/or fluctuations in fuel composition. As such, MSU believes that the proposed CO limits for existing coal boilers are not achievable at various loads and suggests the work practice standards be used for compliance.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Robert Ellerhorst

Commenter Affiliation: Michigan State University

Document Control Number: EPA-HQ-OAR-2002-0058-3674-A2

Comment Excerpt Number: 7

Comment: MSU would like to note that U.S. EPA's opinions on the appropriate method to set MACT standards for organic hazardous air pollutants (HAPs) for coal-fired boilers has been inconsistent. In the final rule (March 21, 2011) and reconsidered final rule (December 23, 2011), it was concluded that numerical emission standards for CO were an appropriate method to control organic HAPs. However, in the final Mercury and Air Toxics (MATS) rule signed December 16, 2011(formally known as the Utility MACT), it was determined that numerical emissions standards were not justified and instead requires work practice standards (boiler turning) to minimize CO emissions. Utility and Industrial/Institutional boilers have similar operating deficiencies that cause variations in CO emissions. There are minimal differences between operation of a Utility boiler in comparison to one required to comply with the CO emissions for this regulation. As such, it does not seem appropriate to have deemed a CO emission limitation necessary for a boiler that does not generate electricity for an external customer base (i.e. a Utility boiler) as opposed to one used to provide electricity for a university, such as MSU. Therefore, MSU believes that U.S. EPA should remain consistent with the reasoning used to not require a CO emission limitation for the MATS in this reconsidered rule.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 59

Comment: It is worth noting that in the Electric Utility NESHAP, involving much larger combustion sources, EPA did not try to use CO as a surrogate for organic HAP emissions, concluding those emission meet CAA §112(h) requirements and imposing a work practice requirement instead of a numerical emission limit for organic HAP or for CO as a surrogate for organic HAPs.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Douglas A. McWilliams

Commenter Affiliation: American Municipal Power

Document Control Number: EPA-HQ-OAR-2002-0058-3685-A2

Comment Excerpt Number: 24

Comment: It is not appropriate to treat detection level limited data for purposes of establishing regulatory limits in the same manner as detected values because the uncertainty associated with measurements near or below the method detection limits is too high. All source emission measurements have random (precision) errors associated with the sample collection, sample and equipment handling, sample preparation, and sample analysis. These errors define method detection and quantitation limits and uncertainty in a non-arbitrary, scientific manner. When emission levels are much higher than the magnitude of these errors, there is a high degree of confidence in the measured value obtained from a single or a few test runs. However, as the measured value decreases, the contribution of these errors to the measured value increases, thus decreasing the confidence level in the accuracy of the measured value from a single or a few runs until the point where the measured value cannot be distinguished from the random error ("noise" level). This is the case with the boiler dioxin/furan data. When this occurs, the measurement cannot be distinguished from zero with high confidence.

EPA discovered this during the development of emissions standards for the proposed Utility MACT rule/ 0 during which EPA conducted pilot tests on coal-fired boilers to determine if CO was in fact a proper surrogate for organic HAP. The results of the tests indicated that organic HAP exists in extremely low levels for these utility boilers, and below the point of detection or accurate measurement. These findings are reproduced below:

With complex carbon-based fuels, combustion is rarely ideal and some CO and concomitant organic compounds are expected to be formed. Because CO and organics are both products of poor combustion, it is logical to expect that limiting the concentration of CO would also limit the production of organics. However, it is very difficult to develop direct correlations between the average concentration of CO and the amount of organics produced during the prescribed sampling period in the MPCRf (which was 4 hours for the pilot-scale tests described here). This is especially true for low values of CO as one would expect corresponding low quantities of

organics to be produced. Samples of coal combustion flue gas have mostly shown very low quantities of the organic compounds of interest. Some of the flue gas organics may also be destroyed in the high temperature post combustion zone (whereas the CO would remain stable). Semi-volatile organics may also condense on PM and be removed in the PM control device. The average CO from the pilot-scale tests ranged from 23 to 137 ppm for the bituminous coals tests, from 43 to 48 ppm for the subbituminous coal tests and from 93 to 129 ppm for the Gulf Coast lignite tests. However, it was difficult to correlate that concentration to the quantity of organics produced for several reasons. The most difficult problems are associated with the large number of potential organics that can be produced (both those on the HAP list and those that are not on the HAP list). This is further complicated by the organic compounds tending to be at or below the MDL in coal combustion flue gas samples. Further, there are complications associated with the CO concentration values. Some of the runs with very similar average concentrations of CO had very different maximum concentrations of CO (i.e., some of the runs had much more stable emissions of CO whereas others had some excursions, or "spikes," in CO concentration). For example, one of the bituminous runs had an average CO concentration of 69 ppm but a maximum concentration of 1,260 ppm (due to a single "spike" of CO during a short upset). Comparatively, another bituminous run had a higher average CO concentration at 137 ppm but a much lower maximum CO value at 360 ppm.³¹

EPA's inability to accurately measure organic HAP emissions from these units made it impossible to establish a meaningful correlation between CO and inorganic HAP and made numeric emission limits infeasible. In light of this finding, EPA proposed and finalized a work practice standard for organic HAP for coal and oil-fired boilers in the Utility MACT rule. *See* 76 Fed. Reg. at 25028 ("We are proposing work practice standards because the data confirm that the significant majority of the measured organic HAP emissions from EGUs are below the detection levels of the EPA test methods, and, as such, EPA considers it impracticable to reliably measure emissions from these units.").

[Footnote 30: 76 Fed. Reg. 24976 (May 3, 2011).] [Footnote 31: 76 Fed. Reg. at 25039 (emphasis added). AMP incorporates by reference the full results of EPA's pilot-scale tests from the Utility MACT rule docket as if fully appended hereto and asks that EPA move the test results and all related documents into the Boiler MACT docket and administrative record.]

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Steve Gossett

Commenter Affiliation: Eastman Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3669-A2

Comment Excerpt Number: 1

Comment: Comment Summary: EPA has not justified that numerical emission standards are appropriate for carbon monoxide (CO) for coal-fired boilers and should replace these standards with work practice standards just as it has determined for coal-fired utility boilers.

Note: While EPA has not specifically solicited comment on this issue, we believe it is appropriate for EPA to consider these comments as they are based on data and information that

have become available after the close of the original proposed rule comment period and even after the deadline for filing of petitions for reconsideration. Also, these comments are appropriate as EPA has proposed to revise the emission standards for CO. Therefore, the issue of the appropriateness of the setting of numerical emissions limits is germane to this comment period.

EPA's opinions on the appropriate method to set MACT standards for non-dioxin organic hazardous air pollutants (HAPs) for coal-fired boilers has been inconsistent. On the one hand, in the industrial boiler MACT proposed rule (June 4, 2010) and final rule (March 21, 2011), EPA concluded that the appropriate method is to set numerical emission standards for CO as a surrogate for non-dioxin organic HAP. On the other hand, and subsequent to its decisions on the industrial boiler MACT, EPA concluded for similar coal-fired boilers in the "Utility MACT" proposed rule (May 3, 2011) and final rule (signed December 16, 2011) that numerical emission standards are not justified and instead set work practice standards for non-dioxin organic HAPs (using the same tune-up requirements used to address dioxin emissions).

EPA's discussion of its decision regarding Boiler MACT can be found on page 32018 of the June 4, 2010 preamble.

EPA concludes that controls such as oxidation catalyst designed to reduce CO will also reduce VOC. This is not necessarily true. Many coal-fired boilers emit CO in the range of 50 -100 ppm while emitting less than 1 ppm THC. This fact is supported by EPA's ICR database. Thus, a boiler required to reduce CO to meet the numerical standard could install an oxidation catalyst with no evidence that VOC will be reduced since there is little emitted to begin with. The chart [see submittal for Figure 1] plots all CO and THC paired stack test run data found in EPA's ICR database for industrial, commercial, and institutional boilers. As can be readily observed from this chart, there is no direct relationship between CO and THC for these coal-fired boilers. This draws into question the effectiveness of setting sub-400 ppm CO limits on coal-fired boilers as a means to minimize non-dioxin organic HAP emissions.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Douglas A. McWilliams

Commenter Affiliation: American Municipal Power

Document Control Number: EPA-HQ-OAR-2002-0058-3685-A2

Comment Excerpt Number: 25

Comment: EPA did not perform these extensive organic HAP and correlation tests when promulgating Boiler MACT limits. Instead, EPA relied upon the same presumed correlation between CO emissions and organic HAP emissions that it found impossible to substantiate when it measured similar units under the Utility MACT.³² The large utility boilers analyzed in the Utility MACT rule share the same fuels, design, and combustion characteristics as the smaller utility boilers subject to Boiler MACT. Therefore, low levels of organic HAP would be expected for these smaller units as well, only the levels would be even lower and harder to quantify because the Boiler MACT utilities use less fuel in smaller units. A review of the Boiler MACT emissions database indicates that many of the tests performed for organic HAP produced results that were either non-detect or were at or below the level of reliable measurement. It would be

arbitrary and capricious for EPA to disregard this relevant emissions information and continue to presume that the correlation it was not able to establish for large coal-fired utility boilers nonetheless exists for smaller coal-fired utility boilers. After extensive testing of organic HAPs, EPA determined that organic HAPs were at such low levels that a numeric emission limit for CO was improper. EPA should also impose a work practice standard on small coal-fired utilities under the Boiler MACT rule so there is parity between the regulations for large and small utility boilers. This relief would also reduce the burden on a subset of small entities for which EPA is required to consider mitigation measures.

[Footnote 32: *See, e.g.*, 75 Fed. Reg. 32006, 32018 (June 4, 2010); 76 Fed. Reg. at 15654; 76 Fed. Reg. at 80624.]

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Claudia M. O'Brien, Latham & Watkins LLP

Commenter Affiliation: JELD-WEN, inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3485-A1

Comment Excerpt Number: 13

Comment: In establishing the CO emission standards, EPA also did not take into account the correlation between CO and NO_x emissions. There is an inverse relationship between CO emissions and NO_x emissions. Operating conditions necessary to achieve CO reductions will, therefore, result in NO_x increases. This will be particularly problematic for units that are operating under low NO_x limitations. Some units may be forced to install additional NO_x controls. Other units may simply be unable to comply with both the CO standards and NO_x limitations. Yet, EPA did not consider these consequences in establishing the CO emission standards. Since the operating conditions needed to achieve the CO emission standards will lead to an increase in NO_x emissions, this further undermines EPA's approach and counsels in favor of work practice standards for non-dioxin/furan organic HAP. Given the problems with establishing CO as a surrogate for non-dioxin/furan organic HAP, it is not even clear that the CO standards would result in any HAP reduction.

JELD-WEN respectfully submits that EPA should revise its Boiler MACT reconsideration proposal to repeal its CO emissions standard and replace it with a work practice standard for non-dioxin/furan organic HAP as it did in the Utility MACT proposal.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Robert Ellerhorst

Commenter Affiliation: Michigan State University

Document Control Number: EPA-HQ-OAR-2002-0058-3674-A2

Comment Excerpt Number: 6

Comment: MSU requests that U.S. EPA revise the proposed CO limitations to work practice standards. MSU's experience in operating four coal-fired boilers shows that there are several

factors that have a fairly significant effect on CO emissions including, steam load, CFB bed temperature, and type of fuel fired. MSU operates our units with efficient combustion practices to minimize CO emissions to the maximum extent possible. Factors that facilitate efficient combustion include air-to-fuel ratio; CFB combustion temperatures, residence time, and turbulence (or mixing) of the combustion gases. Maximizing combustion efficiency must be balanced with the potential increase in NOx emissions that could occur when combustion efficiency is associated with high chamber temperatures. Maintaining reduced NOx levels is of particular concern to MSU in order to comply with current air use permit limits for NOx as well as Clean Air Interstate Rule (CAIR) ozone season requirements. MSU is in compliance with all other proposed emission limitations as set forth in that rule. It is uncomprehensible that MSU may have to incur significant costs in order to continue operation for one emission limit that was set with data that does not take into account variations in operation of boilers.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Claudia M. O'Brien, Latham & Watkins LLP
Commenter Affiliation: JELD-WEN, inc.
Document Control Number: EPA-HQ-OAR-2002-0058-3485-A1
Comment Excerpt Number: 12

Comment: In addition to the fact that EPA has disproven the correlation between CO and organic HAP and that EPA has met the legal requirements for adopting a work practice standard both in Utility MACT and here, other factors suggest that EPA *should* abandon its CO emission limitation and adopt a work practice standard for non-dioxin/furan organic HAP. For instance, a potential unintended consequence of requiring the CO emission standard rather than a work practice standard is that some units may be forced to curtail biomass-fired operations in favor of more fossil fuel-fired operations. As an example, if a boiler with a 122 MM BTU/hr rating were limited to a 500 ppm CO limit (corrected to 7%), it would have to dramatically cut back wood combustion to meet this limit.³⁹ Additional fossil fuel would be combusted to replace the biomass fuel, and this action could result in emission of 5.5 tons of SO₂ for each ton of CO controlled (corresponding to a completely unknown if any- organic HAP reduction). It would be unfortunate if EPA's proposed CO emission standard forced facilities to curtail construction of new biomass burning units when the Agency and many states have been actively promoting biomass for sound environmental reasons. [Footnote 39: We note that several of the biomass CO limits are even more stringent than this illustration and would likely require further curtailment of biomass use.]

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Eric Guelker, Alliant Energy Corporate Services, Inc.
Commenter Affiliation: Interstate Power and Light Company (IPL) and Wisconsin Power and Light Company (WPL), Alliant Energy Corp.
Document Control Number: EPA-HQ-OAR-2002-0058-3492-A1
Comment Excerpt Number: 3

Comment: Alliant Energy believes that the CO emission limits in the final rule are unnecessary in any case and are especially onerous for existing and new light oil-fired house heating boilers less than 100 mmBtu/hr that are burning the cleanest distillate fuel oil available (i.e., ultra-low sulfur content less than 15 ppm). These units may not be able to be retrofitted with further emission controls sufficient to achieve the stringent CO emission limitations in the final rule due to physical space constraints. Furthermore, in some cases, the units may also be constrained by a lack of available natural gas pipeline and unable to switch fuel.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Elizabeth McMeekin

Commenter Affiliation: PPG Industries, Inc

Document Control Number: EPA-HQ-OAR-2002-0058-3778-A1

Comment Excerpt Number: 2

Comment: PPG strongly supports the use of work practices as MACT for gas-fired boilers.

A correlation between a reduction in CO concentration and a corresponding reduction in organic HAP emissions below a CO concentration of approximately 100 ppmv for Gas 2 fueled sources has not been definitively established. Thus, setting a very low standard for CO does not ensure a proportional reduction in the organic HAP emissions, and may have the unintended consequence of increasing emissions of other pollutants such as nitrogen oxides due to the combustion of additional fuel and suboptimal operating conditions. Work practices are more appropriate.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

102E. Alternative CO Standards Corrected to a CO₂ Concentration [DENIED PETITIONER ISSUE]

Commenter Name: Traylor Champion

Commenter Affiliation: Georgia-Pacific LLC (GP)

Document Control Number: EPA-HQ-OAR-2002-0058-3465-A1

Comment Excerpt Number: 27

Comment: The proposed rule at Tables 1 and 2 to Subpart DDDDD specifies a CO concentration limit for a number of the boiler/process heater subcategories. For each subcategory, an O₂ correction factor is also specified for the CO limit. At Table 5, the proposed rule specifies EPA Methods 3A or 3B for the determination of O₂ and CO₂ concentrations and EPA Method 10 is specified for the measurement of CO concentrations. The purpose of this O₂ CEMS is to serve as the diluent analyzer needed to provide the data for the required O₂ correction data for the CO concentration. PS 2, however, allows the use of either a CO₂ or O₂ diluent analyzer to calculate the O₂ correction. CO₂ is commonly used by other CEMS (NO_x, SO₂, etc.) because CO₂ analyzers are generally considered to be more reliable and stable than O₂ monitors. Many existing boilers/process heaters with existing CEMS will already have a CO₂ CEMS in-place which could also be used for correction of the CO data. While the cited

Performance Standards and EPA Methods would permit its use, the text of the proposed rule appears to require the use of an O2 diluent gas analyzer only. While the use of CO2 data to calculate the O2 correction could be accomplished via a request to EPA for approval of alternative monitoring, amendment of the proposed rule to explicitly allow for its use would be a far more efficient resolution.

GP urges EPA to: Allow CO2 diluent analyzer data to be used to calculate the O2 correction in CO diluent calculations as an option to using O2 diluent analyzer data only.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: John S Williams

Commenter Affiliation: Maine Pulp & Paper Association (MPPA)

Document Control Number: EPA-HQ-OAR-2002-0058-3466-A1

Comment Excerpt Number: 4

Comment: CO Standards should be based on Correction to 11 or 12% oxygen

Boiler MACT requires that the CO limit be standardized to 3% oxygen which is well below where most biomass boilers normally operate. This biases the stack CO higher when the adjustment from operating CO to the 3% standard is made.

Oxygen correction percents should be representative of normal stack conditions under normal operation. Three percent is not normal of most combustion units. This is not normal for the location where a certified CEMS needs to be installed to meet performance specification 1 requirements.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Rick Rosvold

Commenter Affiliation: Xcel Energy Services, Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3682-A2

Comment Excerpt Number: 2

Comment: Xcel Energy's vast experience with wood firing in these boilers coupled with its vast amount of CO CEMs data leads the Company to question the use of a 3% oxygen correction for CO emissions from a solid fuel-fired boiler. A correction factor is normally used to standardize the concentrations of stack constituents (such as CO) to a standard oxygen concentration to remove the effect of dilution or "tramp" air leaking into the exhaust train after combustion. The correction factor should be based on the appropriate engineering guidelines for excess air required for the combustion of the fuel in use. Excess air is required since mixing of air and solid fuel is not perfect, and the combustion reaction must be shifted in order to achieve complete combustion. Engineering guidelines for wet biomass stoker grate boilers call for a minimum of 6% to a maximum of 12% oxygen in the post combustion air. These boilers typically require around 10% oxygen in the exhaust firm. The 3% correction is typically used for

liquid or gaseous fuels which need much less excess air to achieve complete combustion. Xcel Energy therefore requests the CO limit in the final rule be corrected to 7% oxygen as it is the normal and appropriate dilution correction standard for wet biomass stoker boilers.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Heather Parent

Commenter Affiliation: Maine Department of Environmental Protection

Document Control Number: EPA-HQ-OAR-2002-0058-3691-A2

Comment Excerpt Number: 10

Comment: The proposed rule uses a 3% oxygen correction factor for CO emission standards. This correction factor is appropriate for liquid fuel and gaseous fired units, but biomass and multi-fuel fired boilers typically operate with flue gas oxygen levels at 6% to 8%. Maine DEP recommends applying an oxygen correction factor of 7% for the CO emission standards associated with all solid fuel units as EPA had established in the original Major Source Boiler MACT published on September 13, 2004 (69 Fed.Reg. 55228):

"The final rule provides revisions to the CO work practice emission levels. For new sources in the solid fuel subcategory, the work practice standard has been written to be corrected to 7 percent oxygen rather than 3 percent. Units in the gaseous and liquid fuel subcategories still have to correct to 3 percent oxygen."

Units burning only coal may be able to operate at 3% oxygen, but any biomass unit will not operate close to 3% oxygen even when firing auxiliary fossil fuel.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

102F. Alternative Standards for THC [DENIED PETITIONER ISSUE]

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 41

Comment: A total hydrocarbon alternative (THC) standard is needed for coal-fired boilers unable to meet the CO limit. Although EPA has not elected to reconsider (this issue was included in CIBO's petition for reconsideration) its decision to not include a THC option, we are aware that the Agency will be getting significant comment from the regulated community that the proposed CO limits for coal-fired boilers will prove to be problematic. THC is an alternate surrogate to EPA's proposed CO surrogate for non-dioxin organic HAPs. However, EPA, in its response to comments on the June 4, 2010 proposed rule, stated that its Office of Research and Development does not support the use of THC as a surrogate for organic HAP from industrial boilers. No other explanation is given and EPA has failed to respond adequately to a significant comment that goes to the issue of sources' ability to comply with the rule. Some coal boilers

have high (>100 ppm) CO levels but very low (<1 ppm) THC. To avoid forcing owners of these boilers to make large expenditures to the combustor to reduce CO and then add post-combustion control to reduce co-laterally increased NOx emissions, EPA should set an alternative THC limit. Sources, would then conduct stack tests to demonstrate compliance with the THC limit and operate O2 trim systems as an operating parameter.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Steve Gossett

Commenter Affiliation: Eastman Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3669-A2

Comment Excerpt Number: 28

Comment: E.4 CO CEMS-Based Alternative

Comment Summary: An alternative limit using total hydrocarbons as a surrogate should be allowed if EPA determines that work practice standards are not appropriate to control emissions of non-dioxin organic HAPs from coal fired boilers.

Eastman requested that EPA set an alternative THC limit in its comments on the June 4, 2010 proposed rule. The company’s comment and response from EPA to this comment is shown below:

Commenter Name: Stephen R. Gossett

Commenter Affiliation: Eastman Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3137.1

Comment Excerpt Number: 16 This response from EPA is unsatisfactory. EPA cannot simply state that its Office of Research and Development does not support THC as a surrogate without explaining the basis for its disagreement. This EPA position unravels the Agency’s long history of recognizing that THC is good measure of organic emissions. Traditionally, CO monitoring has been preferred over THC monitoring due to technical and cost issues. Never has the EPA questioned that THC would be a better surrogate than CO, especially since THC is a direct measure of organic emissions. CO is more an indicator of combustion conditions. We note, for example, that the Portland Cement MACT sets standards for THC rather than CO as a surrogate for non-dioxin organic HAPs (40 CFR 63 Subpart LLL, Table 1). As we noted in our previous comments, without a THC alternative (which could likely be met with no controls or operational changes), the company will be spending significant funds to comply with the CO limit.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Steve Gossett

Commenter Affiliation: Eastman Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3669-A2

Comment Excerpt Number: 29

Comment: Although EPA has not elected to reconsider (this issue was included in CIBO's petition for reconsideration) its decision to not include a THC option, we are aware that the Agency will be getting significant comment from the regulated community that the proposed CO limits for coal-fired boilers will prove to be problematic. In Eastman's case, it will cause us to make a large capital expenditure (~\$15 M) that we do not believe will have any impact on emissions of non-dioxin organic HAPs. Figure 2 [see submittal for Figure 2] summarizes recent CO and THC CEMS data we have collected on this boiler that demonstrate the CO emissions will not meet the proposed limit and that the THC emissions are very low.

We therefore renew our request that EPA either (1) establish an alternative THC limit under which a source would conduct a performance test to show compliance and set a minimum oxygen trim 30-day rolling average operating limit or (2) allow a source to petition its permitting authority for such an alternative limit.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Steve Gossett

Commenter Affiliation: Eastman Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3669-A2

Comment Excerpt Number: 30

Comment: EPA has sufficient data from its 2009 ICR Phase II testing program to establish a THC limit. From our analysis of that data, it appears a THC limit of 2 ppm (3 hour stack test) would be appropriate.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Pat Dennis

Commenter Affiliation: Archer Daniels Midland Company

Document Control Number: EPA-HQ-OAR-2002-0058-3670-A2

Comment Excerpt Number: 9

Comment: Strict CO levels will not result in greater reduction of emissions of other organic compounds. If EPA insists on setting CO limits below 100 ppm, the rule should allow for an alternative THC compliance limit. Insisting on compliance with strict CO limits will require sources to increase excess air levels which could adversely affect boiler efficiency and increase NO_x.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

102H. HCl as a Surrogate for Acid Gases [DENIED PETITIONER ISSUE]

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 11

Comment: EPA proffered a new rationale for its use of hydrochloric acid as a surrogate for all acid gases: "it is highly likely that facilities will choose to control these acid gases by applying the same technology and the means for removal of each are similar." Resp. to Comments Vol. 2 (3187.1 Excerpt 12). EPA's new rationale is irrelevant under the well-established test for whether a surrogate is valid. It does not, for example, address HCN's variable relationship to HCl. *See* Comments at 13. Nor has the Agency demonstrated that add-on controls (rather than fuel-substitution or other methods) are the only means of removing all acid gases; as set forth in our comments, fuel choice can effectively reduce acid gas emissions.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Rationale for Subcategories

7A. Limited-Use Units

Commenter Name: Chris M. Hobson

Commenter Affiliation: Southern Company

Document Control Number: EPA-HQ-OAR-2002-0058-3520-A1

Comment Excerpt Number: 4

Comment: The use of a capacity factor is consistent with other regulations and requirements. Although some limited use boilers may choose to take a limit based on hours of operation for ease of monitoring, it makes more sense for many boilers to monitor their capacity factor on a heat input basis. In many cases, monitoring heat input (fuel use) is something the units are already required to do for other regulations, such as New

Source Performance Standard (NSPS) subparts Db and De. For example, Georgia Power's Plant McDonough combined-cycle facility, currently under construction, includes two auxiliary boilers that are permitted to operate up to a 10% capacity factor on a heat input basis. This capacity factor permit limit is directly used to determine the applicability of NSPS emission limits for PM, NO_x, and SO₂. Therefore, the capacity factor applicability for a limited use subcategory would be consistent with the applicability for NSPS at many facilities.

Response: The EPA agrees with the commenter, and the definition of the limited use subcategory has been revised in the final rule to be based on a 10 percent capacity factor. The annual operating hour threshold has been removed.

Commenter Name: Chris M. Hobson
Commenter Affiliation: Southern Company
Document Control Number: EPA-HQ-OAR-2002-0058-3520-A1
Comment Excerpt Number: 2

Comment: Southern's subsidiaries own and operate (or are building) 3 natural gas-fired and 6 distillate oil-fired auxiliary boilers. These auxiliary boilers are used to generate the steam necessary to bring a main electric generating unit (EGU), either a combined cycle, a coal-fired, or a nuclear unit, on line. Since the auxiliary boilers are primarily used during unit startup, annual operation is generally very limited (e.g., some are limited to a 10 percent capacity factor, and others generally operate less than 10 percent capacity factor but do not have a permit limit) and each event is usually short in duration (e.g., less than 24 hours). These boilers operate infrequently and only as needed, therefore, it would be difficult to schedule test crews and complete emission testing for all HAPs during the limited period of operation. Thus, it is likely that if EPA did not provide the limited use subcategory, each auxiliary boiler would have to be operated annually for the sole purpose of emission testing. This would create unnecessary boiler operation, fuel usage, and emissions and be contrary to the intent of the CAA.

Response: The EPA thanks the commenter for their support of the limited use subcategory. The definition of the limited use subcategory in the final rule has been revised to be based on a 10 percent capacity factor.

Commenter Name: Rick Rosvold
Commenter Affiliation: Xcel Energy Services, Inc.
Document Control Number: EPA-HQ-OAR-2002-0058-3682-A2
Comment Excerpt Number: 7

Comment: EPA has added a subcategory for limited use boilers. Xcel Energy is generally supportive of this sub-categorization as it eliminates operating these types of units for testing purposes when they otherwise would not be operated.

Xcel Energy does, however, take issue with how these units are defined. The definition includes a requirement that these units have a federally enforceable limit of no more than 876 hours per year of operation. This requirement would force applicability of this standard on units that rarely operate. For example, Xcel Energy owns an auxiliary boiler with a rated heat input of 125 mmBTU/hr at its Sherburne County Generating Plant, which operated a total of 60 hours for 2008, 2009 and 2010 combined. This boiler poses little threat to the environment when operated in this manner. However, this boiler would be subject to the new standard simply because it does not have a federally enforceable permit limit of no more than 876 hours per year of operation. It does not seem to be a reasonable expenditure of precious state permitting resources to force a regulated party to request that the state air permitting authority process a permit amendment to restrict operations of a unit that rarely operates simply to avoid regulation under this standard. We believe that EPA could revise this definition to minimize unnecessary permitting by specifically excluding these limited use units without a permit limit.

Response: The EPA has revised the definition of the limited use subcategory in the final rule to be based on a 10 percent capacity factor, and the annual operating hour threshold has been

removed, see the response to comment EPA-HQ-OAR-2002-0058-3500-A1, excerpt 7. The majority of permits place operating restrictions on a capacity factor basis instead of an operational hour basis, thus the EPA believes the capacity factor approach in the definition is more appropriate.

The EPA has maintained that the 10 percent capacity factor be a federally enforceable limit. It is also appropriate to maintain the requirement that the capacity factor be federally enforceable otherwise it would be difficult for a source or regulatory agency to determine year to year if the source would be in the limited use subcategory. Furthermore, it is a reasonable requirement, and consistent with other regulations (i.e., NSPS subpart Db for industrial boilers), if a source wants to avail itself of the limited requirements (in this case work practice standards) for units that operated on a limited basis compared to other units covered by the regulation.

Commenter Name: Michael Bradley

Commenter Affiliation: The Clean Energy Group

Document Control Number: EPA-HQ-OAR-2002-0058-3495-A1

Comment Excerpt Number: 8

Comment: The Clean Energy Group supports the creation of a limited use subcategory, currently defined as "any boiler or process heater that burns any amount of solid, liquid, or gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and has a federally enforceable limit of no more than 876 hours per year of operation" and subject to a work practice standard. In the utility industry, there are units that typically operate to provide back-up power or steam to power plants when the main generating units are off-line. EPA requested comment on the creation of a limited use subcategory in the final rule, as well as on whether the category should be defined based on capacity factor rather than an annual hours limit. The Clean Energy Group recommends that the subcategory be maintained and defined based on hours of operation at full load or as an annual capacity factor. Specifically, we recommend the same 8 percent annual capacity factor as finalized in the recent MATS. Thus, the limited use subcategory would be defined as "any boiler or process heater that burns any amount of solid, liquid, or gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and either (1) has a federally enforceable limit of no more than 876 hours per year of operation at full load or (2) has an annual capacity factor of less than 8 percent of its maximum or nameplate heat input, whichever is greater, based on a calendar year beginning on the initial date of compliance." (Bold denotes additions.) We also recommend that EPA clarify the requirements for limited use units that may increase operation.

Response: The EPA thanks the commenter for their support of the limited use subcategory. The EPA agrees with the capacity factor approach, but believes that a 10 percent capacity factor is more suitable. The 10 percent capacity is equivalent to the 876 hours at full load that was proposed. See the response to comment EPA-HQ-OAR-2002-0058-3500-A1, excerpt 7 for discussion on the 10% capacity factor. The 8 percent capacity factor finalized in MATS to define limited use was based on review of information and data from actual utility boilers operating on a limited basis. That type of detailed operating data was not available for industrial units. The 10 percent capacity factor is consistent with the definition of "limited use" that was in the original 2004 Boiler MACT and in the NSPS for industrial boilers.

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific LLC (GP)
Document Control Number: EPA-HQ-OAR-2002-0058-3465-A1
Comment Excerpt Number: 2

Comment: GP supports EPA’s retention of the provision in the final rule that subjects boilers and process heaters meeting the definition of the Limited Use Subcategory to only a work practice standard under Section 112(h) of the CAA. As EPA has stated in final rule (76 Federal Register 15634); *“The fact that the nature of these units is such that they operate for unpredictable periods of time, limited hours, and at less than full load in many cases has led EPA to determine that limited use units are a unique class of unit based on the unique way in which they are used and EPA is including a subcategory for these units in the final rule. The unpredictable operation of this class of units makes emission testing for the suite of pollutants being regulated impracticable.”*

EPA has defined a Limited Use boiler or process heater as a unit that operates for less than 876 hours per year. EPA should consider utilizing a 10% annual “capacity factor” rather than annual “operating hours”. The use of a capacity factor would be consistent with the “Limited Use” definition in the vacated Boiler MACT standard and in several other standards. Even with this change to the definition, the affected units would continue to be utilized sporadically, during unpredictable periods of time, and for a limited time. The use of a capacity factor versus annual operating hours will not diminish the justification EPA utilized in the development of this subcategory.

Response: The EPA thanks the commenter for their support of work practice standards for sources classified as limited use units. See the response to comment EPA-HQ-OAR-2002-0058-3500-A1, excerpt 7 regarding the definition of limited use with capacity factor instead of operating hours.

Commenter Name: Lee Zeugin and Lauren Freeman
Commenter Affiliation: Utility Air Regulatory Group (UARG)
Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1
Comment Excerpt Number: 7

Comment: Electric utility auxiliary boilers often idle at very low loads to support the reliability of the generating units they serve. As a result, these boilers can be called on to operate more than 876 hours per year but still have annual capacity factors well under 10 percent. An example of a typical auxiliary boiler’s operation, supplied by a UARG member, involves a 314 MMBtu/hour auxiliary boiler having a maximum annual heat input of 2,750,640 MMBtu - its hourly heat rate times an assumed 8760 hours of operation per year. The actual usage of that unit over a five year period was as follows: [See submittal for data table provided by the commenter.]

This example shows that defining the limited use subcategory in terms of capacity factor instead of hours of operation would not result in higher HAP emissions.⁵ Defining the limited use subcategory in terms of capacity factor would provide more operational flexibility to IB units, especially those that must run at low idling rates to support facility operations. EPA should retain

the work practice standards for the limited use subcategory but define the category based on annual capacity factor rather than hours of operation.

[Footnote]

(5) Indeed, under the limited use definition in the 2011 final rule, a unit could operate at a capacity factor of up to 10 percent and still qualify for the subcategory - 876 hours of operation at 100 percent load.

Response: The EPA agrees that the definition of the limited use subcategory should be defined only using a capacity factor and not a set annual hours of operation. We agree that the potential to emit is the same for 876 hours of operation or 10% capacity factor. We agree with commenters that basing limited use on the annual capacity factor provide more operational flexibility because we are aware of situations where units are brought on line at low load to provide spinning reserves to meet electrical demand increases or steam requirement increases. See the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 2 for discussion of the capacity factor applicability to work practice standards.

Commenter Name: Mark Thoma, Principal, Environmental Services Department

Commenter Affiliation: Otter Tail Power Company

Document Control Number: EPA-HQ-OAR-2002-0058-3436-A1

Comment Excerpt Number: 1

Comment: Otter Tail believes that a limited-use subcategory based on a 10% capacity factor will result in a reduction of air pollutants at least equivalent to a subcategory based on a 10% operating factor, and therefore qualifies as an alternative standard under Section 112(h)(3) of the Clean Air Act. This can be explained by the simple fact that the proposed rule allows any limited-use boiler to operate 876 hours at 100% capacity in a year, in which case the boiler would have both a 10% operating factor and a 10% capacity factor. Therefore, the potential-to-emit of any air pollutant would not increase by changing the limited-use subcategory to a 10% capacity factor basis since a boiler still would not be allowed to operate more than 876 hours at 100% capacity. Unfortunately, as currently proposed, the rule unduly creates “winners” and “losers” by favoring entities that operate their limited-use boilers at full capacity versus entities that operate their limited-use boilers at low capacity factors. Also, it should be noted that the final rule, “National Emission Standards for Hazardous Air Pollutants from Coal and Oil-fired Electric Utility Steam Generating Units”, creates a limited-use liquid oil-fired subcategory that is defined based on a capacity factor (*77 Fed. Reg.* at 9486). If EPA was able to justify a capacity factor definition for EGUs, Otter Tail is curious as to why it could not be justified for Industrial Boilers.

Response: See the response to DCN: EPA-HQ-OAR-2002-0058-3500-A1, excerpt 7 regarding inclusion of the capacity factor in the limited use definition, the response to DCN: EPA-HQ-OAR-2002-0058-3465-A1, excerpt 2 for discussion on capacity factor applicability to work practice standards, and the response to DCN: EPA-HQ-OAR-2002-0058-3495-A1, excerpt 8 for discussion on the Utility MACT and its use of capacity factor in relation to the boiler rule.

Commenter Name: Russell A. Wozniak
Commenter Affiliation: The Dow Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3449-A1
Comment Excerpt Number: 30

Comment: EPA's current definition of Limited-use boiler or process heater limits the source to no more than 876 hours per year of operation. EPA should also consider adding an option to the definition that includes sources that have an annual average capacity factor of no more than 10 percent.

Actual emissions from boilers and process heaters are typically a function of both hours per year of operation and operating rate. By adding an option to use an annual average capacity factor approach, the owner/operator would have the flexibility to operate for slightly more than 876 hours per year if the combustion source operates at less than 100% maximum heat input. Typically, operating in this mode should not result in more emissions than operating at 100% load for 876 hours per year. Given an additional option, the owner/operator could either record the number of operating hours or could calculate the annual capacity factor for a calendar year.

Thus, the definition of Limited-use boiler or process heater could be amended as follows:

"means any boiler or process heater that burns any amount of solid, liquid, or gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and has a federally enforceable limit of no more than 876 hours per year of operation or has an annual capacity factor of no more than 10.0 percent.

In addition, EPA could adopt the following definition of "annual capacity factor" from the 2004 version of the rule:

Means the ratio between the actual heat input to a boiler or process heater from the fuels burned during a calendar year, and the potential heat input to the boiler or process heater had it been operated for 8,760 hours during a year at the maximum steady state design heat input capacity.

Response: The EPA agrees that the capacity factor should be included in the definition of limited use in the rule, and the definition has been revised accordingly. See the response to comment EPA-HQ-OAR-2002-0058-3500-A1, excerpt 7 for discussion on basing the definition on capacity factor. See the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 2 for discussion on capacity factor applicability to work practice standards.

Commenter Name: Lenny Dupuis
Commenter Affiliation: Dominion Resources Services, Inc.
Document Control Number: EPA-HQ-OAR-2002-0058-3486-A1
Comment Excerpt Number: 2

Comment: EPA should establish an alternative definition of the subcategory for auxiliary oil-fired boilers located at electric generating stations that would include units that operate at 10 percent or less of their annual capacity factor rather than 10 percent of the annual operating hours. EPA applied a percent of annual capacity factor-based approach in defining a limited use

subcategory for oil-fired units in the final Utility Mercury and Air Toxics Rule (MATS) on the basis that the operation of such units is infrequent and unpredictable, that numeric standards based on base load units would not likely be achievable during the very limited times these units operate and that required emission testing under the rule could require the operation of these units when they otherwise may not be needed for the sole purpose of testing, resulting in added costs (related to testing) and the release of hazardous air pollutants that otherwise would not have been emitted.¹

The same case can be made for auxiliary boilers used within the electric utility industry to generate the steam necessary to bring a main electric generating unit (EGU) on line (during startup). Since auxiliary boilers are primarily operated during unit startup, operation of these boilers is typically very limited and sporadic. The cost for sources with oil-fired auxiliary boilers to install and maintain the control equipment (and potentially monitoring equipment) necessary to meet emissions standards would be excessive, particularly for a unit that operates infrequently. In addition, since the demand for an auxiliary boiler to operate is very difficult to forecast, it is possible that each auxiliary boiler would have to be operated some time during each year for the sole purpose of emission testing.

Such an outcome would result in otherwise unnecessary emissions of air pollutants and use of a valuable and not unlimited resource (low sulfur diesel fuel). Furthermore, EPA applied a 10 percent capacity utilization factor as a means to define a limited use unit for several subcategories in the 2004 Industrial Boiler MACT rule.² Therefore, a subcategory for oil-fired auxiliary boilers defined with a 10 percent annual capacity factor should qualify for work practice standards in the reconsideration rule. In addition, the definition of a limited-use boiler (40 CFR 63.7575) should be revised to accommodate a capacity factor-based threshold.

[Footnote]

(2) 69 *Fed. Reg.* 55223.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3500-A1, excerpt 7 regarding inclusion of the capacity factor in the limited use definition, the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 2 for discussion on capacity factor applicability to work practice standards and the 2004 vacated Boiler MACT and its use of capacity factors in relation to the boiler rule, and the response to comment EPA-HQ-OAR-2002-0058-3495-A1, excerpt 8 for discussion on the Utility MACT and its use of capacity factor in relation to the boiler rule.

Commenter Name: Kenneth Anderson

Commenter Affiliation: Ameren Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3487-A1

Comment Excerpt Number: 1

Comment: Ameren agrees with US EPA's inclusion of a limited use boiler and process heater subcategory in the final rule. However, Ameren believes improvements to the definition of limited use boilers and process heaters can easily be made without compromising air quality. Ameren requests that US EPA reconsider the use of a straight hourly threshold for defining the limited use subcategory.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3500-A1, excerpt 7 regarding inclusion of the capacity factor in the limited use definition.

Commenter Name: Kenneth Anderson

Commenter Affiliation: Ameren Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3487-A1

Comment Excerpt Number: 5

Comment: Because emissions of HAPs are directly proportional to capacity factor as opposed to time on line, capacity factor is a much better surrogate for defining the limited use subcategory. Emissions from the auxiliary boiler discussed above never approached those of a boiler operating at design heat input for 876 hours as allowed under the current limited use exemption. Just because the boiler was needed for more than 876 hours to meet facility needs should not elevate the boiler out of the limited use subcategory if the capacity factor remains less than 10 %.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3500-A1, excerpt 7 regarding inclusion of the capacity factor in the limited use definition and for discussion on changes in load and its impact on capacity factor versus operating hours, and the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 2 for discussion on capacity factor applicability to work practice standards.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 35

Comment: In the Final Boiler Rule, EPA reiterates its support for a limited use subcategory, noting that limited use units are a unique class of units and that forcing them to start up solely to conduct emissions testing would be impractical and lead to increased emissions:⁷⁶ *Fed. Reg.* 15634.

However, ACC believes that units operating at less than 10 percent of their annual capacity factor or less than 10 percent of the annual operating hours should qualify as limited use units. A capacity utilization factor of 10 percent was chosen for the vacated 2004 boiler MACT final rule as the best means of defining a limited use unit.¹⁵ This definition is equally appropriate for the current rule. EPA has taken a capacity factor approach in the final MATS rule, establishing a subcategory for limited use liquid-fired units with an 8 percent capacity factor (limited-use liquid Docket EPA-HQ-OAR-2002 oil-fired subcategory means an oil-fired electric utility steam generating unit with an annual capacity factor of less than 8 percent of its maximum or nameplate heat input, whichever is greater, averaged over a 24-month block contiguous period).¹⁶ Therefore, ACC requests that EPA define the limited use subcategory to give sources the option of complying with an annual hourly limit or an annual capacity factor.

[Footnote 12: 75 Fed. Reg. 32023 (June 4, 2010)]

[Footnote 13: *See* Response to Public Comments on Proposed Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP EPA-HQ-OAR-2002-0058-0649]

[Footnote 14: National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters; Final Rule, 69 FR 55218, 55232 (September 13, 2004).]

[Footnote 15: *See* National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters; Final Rule, 69 Fed. Reg. at 55223.]

[Footnote 16 *See* 40 CFR 63.10000 and 63.10042.]

Response: See the response to comment EPA-HQ-OAR-2002-0058-3500-A1, excerpt 7 regarding inclusion of the capacity factor in the limited use definition, the response to comment EPA-HQ-OAR-2002-0058-3495-A1, excerpt 8 for discussion on the Utility MACT and its use of capacity factor in relation to the boiler rule, and the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 2 for discussion on the 2004 vacated Boiler MACT and its use of capacity factor in relation to the boiler rule.

Commenter Name: Felix Mestey, on behalf of Donald R. Schregardus

Commenter Affiliation: Clean Air Act Services Steering Committee, Department of Defense (DoD)

Document Control Number: EPA-HQ-OAR-2002-0058-3427

Comment Excerpt Number: 1

Comment: Discussion

Section V. B. 7. of the preamble requests comment on how a subcategory defined with a 10% capacity factor would qualify for work practice standards in lieu of emission limits and indicated that this was requested by several petitioners who failed to provide support that such a subcategory would qualify for work practice standards under section 112 of the Clean Air Act.

Boilers and process heaters may operate at varying capacities depending on the load requirements. In some cases, boilers and process heaters may be oversized and operate above the hourly limit suggested for limited use yet still be below a 10% operating capacity. In order to verify that the low use boilers and process heaters operate below the proposed 10% capacity,

EPA could provide the option to measure fuel use on a monthly basis and then average the operation of the boilers and process heaters over that monthly period. By using the total monthly fuel use and comparing it with the maximum potential available to the boilers and process heaters, an actual load capacity can be determined. This monthly monitoring period aligns with many current air pollution control district permit requirements allowing for an easy transition.

DoD also noted that some boilers and process heaters operate seasonally and that applying the capacity limit for limited use would be a more appropriate measure for determining the limited use category and would be consistent with 40 CFR part 60, which has different requirements for units with an annual capacity factor of 10% or less and defines annual capacity factor as follows: *"Annual capacity factor means the ratio between the actual heat input to a steam generating unit*

from the fuels listed in §60.42b(a), §60.43b(a), or §60.44b(a), as applicable, during a calendar year and the potential heat input to the steam generating unit had it been operated for 8,760 hours during a calendar year at the maximum steady state design heat input capacity. In the case of steam generating units that are rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility in a calendar year."

Recommendation.

DoD recommends that EPA retain the 10% of hours/year (876 hours) while adding a capacity-based approach for determining limited use. Revise the definition of "limited use boiler or process heater" based on language used in the definition of annual capacity factor in 40 CFR part 60 as follows:

Limited-use boiler or process heater means any boiler or process heater that burns any amount of solid, liquid, or gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and has a federally enforceable limit of no more than either 876 hours per year of operation or a fuel consumption equivalent to 10 percent of the maximum steady state design heat input capacity.

Response: The EPA disagrees with the suggestion for capacity factors to be applied on a monthly basis. This would be inconsistent with other provisions in the rule which are required on an annual basis, specifically performance testing. The EPA acknowledges that sources may exhibit load variability, but determining compliance with the capacity factor criteria would be inappropriate for units that operate only during a month or two during the year. In those cases, their annual capacity factors might be well below 10 percent whereas their capacity factor for those months would be well above 10 percent causing the unit to be in violation of the permit. See the response to comment EPA-HQ-OAR-2002-0058-3500-A1, excerpt 7 regarding inclusion of the capacity factor in the limited use definition, and the response to comment EPA-HQ-OAR-2002-0058-3495-A1, excerpt 8 for discussion on the Utility MACT and its use of capacity factor in relation to the boiler rule.

Commenter Name: Allison Watkins, Baker Botts

Commenter Affiliation: Class of '85 Regulatory Response Group

Document Control Number: EPA-HQ-OAR-2002-0058-3608-A1

Comment Excerpt Number: 6

Comment: The Group supports the existing definition of limited use units established by the Major Source Rule, but recommends that EPA adopt an additional, alternative definition of limited use unit based on an annual capacity factor. Defining limited use unit based on either the hours of operation *or* an annual capacity factor will provide important regulatory flexibility that will make compliance for many sources less burdensome.⁶ EPA currently defines a limited use unit as a unit that burns any amount of solid, liquid, or gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and has a federally enforceable limit of no more than 876 hours per year of operation. The Class of '85 recommends that EPA adopt an additional, alternative definition based on an 8 percent annual capacity factor as finalized in the recent Mercury and Air Toxics Standards for Utilities ("MATS").⁸ A limited use unit would therefore be defined as "any boiler or process heater that burns any amount of solid, liquid, or gaseous

fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and either (1) has a federally enforceable limit of no more than 876 hours per year of operation at full load *or* (2) has an annual capacity factor of less than 8 percent of its maximum or nameplate heat input, whichever is greater, averaged over a calendar year beginning on the initial date of compliance.” Adopting this alternative definition of limited use unit will simplify the regulatory requirements applicable to companies that own or operate boilers and electric generating units.

[Footnote 6: The Group also requests that EPA clarify the requirements for limited use units that subsequently increases operation.]

[Footnote 8: 77 Fed. Reg. 9304, 9371 (Feb. 16, 2012).]

Response: See the response to comment EPA-HQ-OAR-2002-0058-3495-A1, excerpt 8.

Commenter Name: Randal G. Oswald

Commenter Affiliation: Integrys Energy Group

Document Control Number: EPA-HQ-OAR-2002-0058-3659-A2

Comment Excerpt Number: 6

Comment: Integrys supports the limited use subcategory established by the Major Source Rule, but recommends that EPA adopt an alternative definition of limited use unit based on an annual capacity factor. Defining limited use unit based on hours of operation *or* an annual capacity factor will provide important regulatory flexibility that will make compliance for many sources less burdensome.³

EPA currently defines a limited use unit as a unit that burns any amount of solid, liquid, or gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and has a federally enforceable limit of no more than 876 hours per year of operation.⁴ We recommend that EPA adopt an alternative definition based on an 8 percent annual capacity factor as finalized in the recent Mercury and Air Toxics Standards for Utilities (“MATS”).⁵ A limited use unit would therefore be defined as “any boiler or process heater that burns any amount of solid, liquid, or gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and either (1) has a federally enforceable limit of no more than 876 hours per year of operation at full load *or* (2) has an annual capacity factor of less than 8 percent of its maximum or nameplate heat input, whichever is greater, averaged over a calendar year beginning on the initial date of compliance.” Adopting this alternative definition of limited use unit will simplify the regulatory requirements applicable to companies that own or operate boilers and electric generating units.

[Footnotes]

(3) The Group also requests that EPA clarify the requirements for limited use units that subsequently increases operation.

(4) 40 C.F.R. § 63.7575.

(5) 77 Fed. Reg. 9304, 9371 (Feb. 16, 2012).

Response: See the response to comment EPA-HQ-OAR-2002-0058-3495-A1, excerpt 8 regarding the inclusion of an 8% capacity factor in the limited use definition, the response to

comment EPA-HQ-OAR-2002-0058-3500-A1, excerpt 7 for discussion on changes in load and its impact on capacity factor versus operating hours, and the response to comment EPA-HQ-OAR-2002-0058-3518-A1, excerpt 1 for discussion on using the calendar year basis.

Commenter Name: Chris M. Hobson

Commenter Affiliation: Southern Company

Document Control Number: EPA-HQ-OAR-2002-0058-3520-A1

Comment Excerpt Number: 5

Comment: The use of capacity factor provides more operational flexibility and does not count periods of boiler startup equivalent to normal operation. Limited use boilers spend much of their operating time in startup and shutdown and typically cannot serve their intended purpose until reaching a certain load. Under an hourly operating restriction, however, the hours of low load and low heat input during startups and shutdowns would be treated equivalency to full load operation. At Plant McDonough, for example, the boiler may only operate for approximately eight hours at a time during normal conditions, but the startup will take about four hours, or half of the total operation. Thus, under EPA's proposed hourly limit, the period of time with low fuel consumption and heat input (i.e., startup) would be treated equivalency to full load operation. This would require auxiliary boilers, such as those at Plant McDonough, that already have a very stringent 10% capacity factor limit, to take even further operational restrictions to qualify as limited use boilers under the Industrial Boiler MACT.

Response: The EPA agrees with defining the limited use subcategory using an emission factor approach. See the response to comment EPA-HQ-OAR-2002-0058-3500-A1, excerpt 7 regarding the definition of limited use with capacity factor instead of operating hours.

Commenter Name: Kenneth Anderson

Commenter Affiliation: Ameren Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3487-A1

Comment Excerpt Number: 2

Comment: US EPA should consider changing the definition of limited use to: "Limited-use boiler or process heater that burns any amount of liquid or gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour, and has an annual capacity factor of no more than 10 %." The definition of annual capacity factor should then be added to the definitions in 40 CFR 63.7575 and it should be the same as the definition of annual capacity factor in both 40 CFR 60.41 b and 40 CFR 60.41 c.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3500-A1, excerpt 7 regarding the definition of limited use with capacity factor instead of operating hours and the response to comment EPA-HQ-OAR-2002-0058-3495-A1, excerpt 8 for discussion on the Utility MACT and its use of capacity factor in relation to the boiler rule.

Commenter Name: Lee Zeugin and Lauren Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1

Comment Excerpt Number: 6

Comment: EPA chose to define the limited use subcategory based on the number of hours a unit operates - units having a federally enforceable limit of no more than 876 hours per year of operation qualify for the subcategory.⁴ UARG believes that the limited use subcategory should be based not on the number of hours a unit operates but rather on a unit's annual capacity factor. Units that operate at an annual capacity factor of 10 percent or less should qualify for the limited use subcategory.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3500-A1, excerpt 7 regarding the definition of limited use with capacity factor instead of operating hours.

Commenter Name: Chris M. Hobson

Commenter Affiliation: Southern Company

Document Control Number: EPA-HQ-OAR-2002-0058-3520-A1

Comment Excerpt Number: 3

Comment: While the final rule promulgated on March 21, 2011 defined the limited use subcategory to include units that operate less than 10 percent of the hours in a year, EPA requested comment in the reconsideration on defining the subcategory to include units that operate with less than a 10 percent capacity factor. Southern requests that EPA expand the definition in the final rule to allow limited use units, such as auxiliary and startup boilers, to operate up to a 10 percent capacity factor without being subject to emission limits and testing requirements. EPA should define the limited use subcategory based on capacity factor.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3500-A1, excerpt 7 regarding the definition of limited use with capacity factor instead of operating hours.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 74

Comment: We support the creation of this subcategory due to the many reasons listed in our previous comments.³⁹ We also support work practices as the appropriate compliance approach for this subcategory. However, we believe that units operating at less than 10 percent of their annual capacity factor, rather than 10 percent of the annual operating hours, should qualify as limited use units. A capacity utilization factor of 10 percent was chosen for the previous boiler MACT final rule as the best means of defining a limited use unit.⁴⁰ This definition is equally appropriate for the current rule.

[Footnote 39: AF&PA comments on June 4, 2010 proposal at EPA-HQ-OAR-2002-0058-3213 (pp. 184-192), reconsideration petition at EPA-HQ-OAR-2002-0058-3293]

[Footnote 40: *See* National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters; Final Rule, 69 Fed. Reg. at 55223.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3500-A1, excerpt 7 regarding the definition of limited use with capacity factor instead of operating hours, and the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 2 for discussion on the 2004 vacated Boiler MACT and its use of capacity factor in relation to the boiler rule.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 5

Comment: EPA seeks comment on how a limited use subcategory defined with a 10% capacity factor would qualify for work practice standards in lieu of emission limits. CIBO in its Petition for Reconsideration, sought a change in the limited-use definition to be based on a 10% annual capacity factor, and a work practice standard for these units. EPA did not rely on a capacity factor in the Proposed Reconsidered Rule, but in the Utility MATS rule, EPA used an 8% factor, which CIBO supports. A capacity utilization factor of 10 percent was chosen for the 2004 Boiler MACT final rule as the best means of defining a limited use unit. This definition is equally appropriate for the current rule. A capacity factor versus hour of operation is a reasonable method for defining the limited use subcategory.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3500-A1, excerpt 7 regarding the definition of limited use with capacity factor instead of operating hours, and the response to comment EPA-HQ-OAR-2002-0058-3495-A1, excerpt 8 for discussion on the Utility MACT and its use of capacity factor in relation to the boiler rule, and the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 2 for discussion of the 2004 vacated Boiler MACT and its use of capacity factor in relation to the boiler rule.

Commenter Name: J. Michael Geers

Commenter Affiliation: Duke Energy

Document Control Number: EPA-HQ-OAR-2002-0058-3543-A1

Comment Excerpt Number: 20

Comment: The EPA added a subcategory for limited-use units in the final rule, and subsequently petitioners requested the opportunity to comment on the creation of the subcategory and the definition of the subcategory. EPA indicated that multiple petitioners requested that rather than defining the subcategory to include units that operate less than 10 percent of the hours in a year, the EPA define the subcategory to include units that operate with a capacity factor of 10 percent or less. Duke Energy agrees that the limited use subcategory should be defined based on a 10% capacity factor. EPA goes on to state that:

The petitioners believe that such a change would provide more flexibility, but petitioners did not provide support that such a subcategory would qualify for work practice standards under section 112 the CAA. Therefore, the EPA is not proposing a change to the final approach but is requesting comment on how a subcategory defined with a 10 percent capacity factor would qualify for work practice standards in lieu of emission limits.

Duke Energy disagrees with EPA's statement in that the reasons for establishing a limited use subcategory based on capacity factor are essentially the same as those used to justify a subcategory based on hours of operation. The distinction is only a matter of minor difference in definition. Duke Energy believes that using capacity factor instead of a limit based on hours of operation is a reasonable approach for defining this boiler category.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3500-A1, excerpt 7 regarding the definition of limited use with capacity factor instead of operating hours, and the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 2 for discussion on capacity factor applicability to work practice standards.

Commenter Name: J. Michael Geers

Commenter Affiliation: Duke Energy

Document Control Number: EPA-HQ-OAR-2002-0058-3543-A1

Comment Excerpt Number: 21

Comment: Duke Energy believes that using capacity factor instead of a limit based on hours of operation is a reasonable approach for defining this boiler category. Limited use units are likely to be operated infrequently. Many will be in cold-standby until their operation is needed. Compared to combustion turbines and IC engines, boilers require more time for startup. This can be 2 to 4 hours for a smaller unit, and several hours to a day for larger units. During portions of the start-up, the boiler is not producing steam for use by its load customers. As currently defined, start-up would constitute an "operating hour", decreasing the available hours for a limited use boiler to operate.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3500-A1, excerpt 7 regarding the definition of limited use with capacity factor instead of operating hours, and for discussion of changes in load and its impact on capacity factor versus operating hours.

Commenter Name: J. Michael Geers

Commenter Affiliation: Duke Energy

Document Control Number: EPA-HQ-OAR-2002-0058-3543-A1

Comment Excerpt Number: 23

Comment: Duke Energy believes that using capacity factor instead of a limit based on hours of operation is a reasonable approach for defining this boiler category. The use of a 10% capacity has precedent in other EPA rulemakings. For example 40 CFR 75, Appendix E, provides relief from the burdensome NO_x continuous emissions monitoring requirements of the Acid Rain Program for affected units that limit the capacity factor to less than 10% on a 3-year average. In addition in 40 CFR Part 60, for subpart DB units, EPA established a 10% capacity factor for limited use units. The CAA gives EPA discretion to define subcategories based on size, type and class. Clearly EPA has the authority to define the limited use subcategory based on a 10% capacity factor.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3500-A1, excerpt 7 regarding the definition of limited use with capacity factor instead of operating hours, and the

response to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 6 regarding the relationship to the Acid Rain program limited use subcategory.

Commenter Name: Robert R. Perry

Commenter Affiliation: FirstEnergy Generation Corp (FGCO)

Document Control Number: EPA-HQ-OAR-2002-0058-3518-A1

Comment Excerpt Number: 1

Comment: FGCO supports EPA's inclusion of the "limited use" exemption for boilers operated less than 876 hours annually but encourages EPA to broaden the exemption. FGCO has a number of liquid fired (No. 2 fuel oil) ICI boilers with rated heat inputs greater than 10 mmBtu/hr which would be subject to the proposed ICI Boiler MACT limits. These industrial-sized boilers are used very infrequently to provide a source of steam to power steam driven auxiliaries for much larger electric generating units (EGU) during the start-up process and potentially for station heating.

We encourage EPA to broaden the "limited use" exemption by:

- 1) excluding startup and shutdown operating time from the 876 hours which EPA has excluded for other subcategories,
- 2) excluding tune-up activity hours from the 876 hours,
- 3) dropping the requirement that the limited use exemption be "federally enforceable" which unnecessarily complicates the exemption (maintaining records as required in the regulations should be sufficient to demonstrate compliance),
- 4) allowing dual fuel boilers that are capable of burning both natural gas and liquid fuel to exclude the operating time on natural gas from the 876 hours,
- 5) allowing the compliance period to be on a calendar year basis running January to December, and
- 6) allowing a multiple year averaging time such as five years under the limited use exemption.

Response: The EPA thanks the commenter for their support of the limited use subcategory. The EPA has revised the definition of the limited use subcategory in the final rule to be based on an average annual 10 percent capacity factor, and has removed the annual operational hour threshold. See the response to comment EPA-HQ-OAR-2002-0058-3500-A1, excerpt 7.

The EPA disagrees that the "federally enforceable" clause causes unnecessary complications with the definition of the subcategory, See the response to comment EPA-HQ-OAR-2002-0058-3682-A2, excerpt 7.

The EPA also disagrees with the commenter's request that natural gas combustion should be excluded from operating time consideration; a limited use unit is one that operates infrequently regardless of the fuels being combusted in it. The commenter is suggesting an approach to circumvent the Gas 1 subcategory limitation on combusting oil outside of periods of gas curtailment which is inappropriate.

The EPA also disagrees with a multiple year averaging time since the definition has been changed to annual capacity factor from hours per year. Averaging over multiple years is not appropriate because in any one year the unit could operate well beyond the limited use criteria resulting in emissions much higher than a simpler operated unit that in the limited use subcategory and subject to emission limits instead of work practices.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 34

Comment: *WORK PRACTICES FOR LIMITED-USE UNITS*

EPA has appropriately established a subcategory for —limited use units. Limited use sources operate intermittently and for shorter periods of time (*e.g.*, small package boilers that are only used during plant outages, a backup boiler that runs when other units are being fixed, a peaking unit used to supplement electric generation during particularly hot summer days, a process heater that operates for a few hours at a time to warm up a heat transfer fluid for use in a chemical process, or a process heater that only operates intermittently in order to maintain the temperature of a process fluid in the desired range). Compared to most boilers and process heaters, these units spend a relatively greater percentage of their time starting up and shutting down. As a result, their emissions profiles differ from sources which operate for long periods of time in efficient steady-state manners. For example, the limited-use units are likely to experience higher CO levels as the boiler or process heater heats up during startup due to incomplete combustion. Similarly, many pollution control technologies are either difficult to use or ineffective during startup and shutdown periods and would be cost prohibitive to install and use for only short periods of time during a year. These are just the sort of "class" and "type" distinctions that merit consideration for subcategorization under §112(d)(2).

Because limited use boilers and process heaters do not operate on a regular schedule and typically operate for only short periods of time, emissions profiles for these boilers and process heaters can vary significantly from those of a similar boiler or process heater operating in a steady state. "Combustion units operate most efficiently when operated at or near their design capacity. The combustion efficiency tends to decrease as the unit's load (steam production) decreases."¹² Given their short run times, there are also technological limitations on how effectively emissions from these units can be controlled, particularly for organic HAP emissions.

EPA indicated the following in the responses to comments on the final 2004 Boiler MACT rule: "[W]e could not identify any control technologies that would reduce organic HAP emissions [for limited use boilers]. Therefore, while larger units may emit more than smaller units, ACC has not identified any appropriate technology or method that could be used to reduce organic HAP emissions."¹³ Finally, since "limited use boilers, when called upon to operate, must respond without failure and without lengthy periods of startup,"¹⁴ a significantly larger percentage of their annual operation will be devoted to maintenance and readiness testing than other commercial, industrial, or institutional boilers. These differences noted in the 2004 boiler rule remain valid today and justify the creation of a subcategory for limited use boilers and process heaters.

[Footnote 12: 75 Fed. Reg. 32023 (June 4, 2010)]

[Footnote 13: *See* Response to Public Comments on Proposed Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP EPA-HQ-OAR-2002-0058-0649][Footnote 14: National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters; Final Rule, 69 FR 55218, 55232 (September 13, 2004).]

Response: See the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 2.

Commenter Name: Alicia Meads

Commenter Affiliation: National Association of Manufacturers (NAM)

Document Control Number: EPA-HQ-OAR-2002-0058-3515-A1

Comment Excerpt Number: 9

Comment: The EPA's establishment of a limited use subcategory subject to work practices is warranted for a variety of reasons previously highlighted by the NAM, including the fact that these units spend a far greater percentage of their time starting up and shutting down than other units, leading to different emission profiles and control options.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 2.

Commenter Name: Chris M. Hobson

Commenter Affiliation: Southern Company

Document Control Number: EPA-HQ-OAR-2002-0058-3520-A1

Comment Excerpt Number: 6

Comment: EPA's rationale for establishing work practice standards for limited use boilers applies whether the subcategory is defined based on hours or capacity factor. In the final Industrial Boiler MACT, EPA states that a limited use subcategory is appropriate because these boilers "operate for unpredictable periods of time, limited hours, and at less than fullload."² EPA goes on to say, "[t]he unpredictable operation of this class of units makes emission testing for the suite of pollutants being regulated impracticable" and "[i]n order to test the units, they would need to be operated specifically to conduct the emissions testing because the nature and duration of their use does not allow for the required emissions testing."³ Southern asserts that establishing a limited use subcategory based on capacity factor rather than hours per year has no impact on this rationale. Under normal conditions, the auxiliary boilers would only be needed when start-up steam is not otherwise available from other electric generating units on-site. It is impossible to predict the frequency and duration of these events in order to schedule emission testing. A limited use subcategory based on capacity factor versus hours per year would serve the purpose of providing operating flexibility during unpredictable startups or number of events, but would in no way change EPA's rationale for a limited use subcategory.

[Footnotes]

(2) 76 Fed. Reg. at 15634

(3) 76 Fed. Reg. at 15634

Response: See the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 2 for discussion on capacity factor applicability to work practice standards.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 35

Comment: Inclusion of a subcategory for limited-use BPH is appropriate.

The March 21, 2011 final rule included a limited-use subcategory that includes units that operate less than 10% of the hours in a year. The rationale for establishing that subcategory was provided at 76 Fed. Reg. 15633-4 (March 21, 2011). Limited-use BPH are significantly different from steady-state units and it is therefore appropriate for them to have their own subcategory. Limited-use units spend a large percentage of their operating time in reduced-efficiency operating conditions. Operating more frequently in these conditions makes emission profiles of limited-use units very different from sources which operate in more efficient steady-state modes. Thus, emission limitations based on continuous operations are not appropriate for limited-use units. EPA was correct to conclude that limited-use BPH are a unique class of unit based on the unique way in which they are used. Furthermore, the unpredictable and varying operation of this class of BPH and their limited operating time makes emission testing for the suite of pollutants being regulated technically infeasible. Thus, application of a design or work practice for emission control to this subcategory is justified and aligns with the requirements of section 112(h) of the CAA.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 2 for discussion on capacity factor applicability to work practice standards, and the response to comment EPA-HQ-OAR-2002-0058-3520-A1, excerpt 2 for discussion on the additional costs which would arise without a limited use category.

Commenter Name: Douglas A. McWilliams

Commenter Affiliation: American Municipal Power

Document Control Number: EPA-HQ-OAR-2002-0058-3685-A2

Comment Excerpt Number: 34

Comment: EPA also requested comment on defining limited use boilers to include those units using no more than 10 percent of their annual capacity, rather than defining them as units operating no more than 876 hours per year. Specifically, EPA asked commenters to explain how such units could qualify for work practice standards pursuant to CAA § 112(h). The justification for applying work practice standards to units using no more than 10 percent of their annual capacity is the same as the justification for applying work practice standards to units operating no more than 10 percent of the year. Industrial boilers cannot maintain steady state operation at very low capacity utilization levels. Limited use boilers will operate between 60 and 95% of rated capacity to ensure stable and efficient operation. Thus, a limited use unit defined on an annual capacity basis will still be operating in response to special circumstances; it cannot operate continuously at or near 10% load.

A capacity-based limit ensures 90% reduction from the maximum allowable annual emissions. The annual hour-based limit has no direct correlation to emissions, making its benefit more difficult to quantify and calculate. Also, capacity utilization is easily measurable because sources track the amount of fuel used and its heat rate. By contrast, the number of "operating" hours is more problematic. Do we count startup and shutdown hours? Does "operating" begin when the primary fuel is introduced? Are partial hours counted or should we use every 60-minutes? Operating hour limits may also incentivize inefficient behavior as operators would be motivated to startup quicker or shutdown faster than conditions may warrant to conserve limited use hours. These complications are unnecessary if EPA adopts 10% of annual capacity as the limited use definition.

Under CAA § 112(h), it is appropriate to establish a work practice standard in lieu of numeric emission limits when these limits are infeasible or technically impracticable. AMP urges EPA to alter the definition of "limited use boiler" to use ten percent of the source's rated annual capacity, rather than ten percent of the annual hours, to increase flexibility and accountability for facilities operating limited use units. EPA is fully justified in creating this subcategory and establishing work practices for limited use units, and should retain this subcategory in the final rule.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 2 for discussion of capacity factor applicability to work practice standards, and the response to comment EPA-HQ-OAR-2002-0058-3520-A1, excerpt 4 regarding the ease of monitoring heat input.

Commenter Name: Kenneth Anderson

Commenter Affiliation: Ameren Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3487-A1

Comment Excerpt Number: 6

Comment: For limited use boilers, the economics of installation of ESPs or fabric filters and activated carbon injection for Hg control, wet scrubbers for control of acid gases and potentially catalytic oxidizers for the control of organic HAPs is not cost effective. Assuming a no.2 fuel oil fired 250 MMBtu/hr auxiliary boiler with a 10 % capacity factor and using AP-42 particulate emission factors, average PM_{2.5} and Hg factors from the US EPA emission test database for the Boiler MACT rulemaking, the particulate emissions (PM) from that boiler is on the order of 1.5 tpy, PM_{2.5} on the order of .3 tpy and Hg on the order of 0.33 lb/yr. Using the US EPA summary of Capital and Annual Costs for control in Table 5 of the Preamble of the proposed rule for the Light Liquid Units, the average annualized cost of control for existing liquid fuel fired boilers after considering fuel savings is \$476,764 per boiler. In terms of cost effectiveness, assuming 100 % reduction of all three pollutants, the annualized cost of reduction is \$317,843 per ton of PM reduction, \$1,589,214 per ton of PM_{2.5} reduced and \$1,444,740 per pound of Hg reduced. We include PM and PM_{2.5} for this analysis because US EPA's benefits analysis for this proposed rule is based on PM_{2.5} reductions. At these costs, it does not make sense to require controls on limited use boilers even as large as 250 MMBtu/hr that are limited to a 10% capacity factor.

Response: The definition of the limited use subcategory has been revised in the final rule to be based on a 10 percent capacity factor, and the annual operating hour threshold has been removed. See response to comment EPA-HQ-OAR-2002-0058-3500-A1, excerpt 7.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 44

Comment: Clearly, the rationale for applying design or work practices to gas-fired BPH is even more applicable to limited use BPH, since those units have even lower emissions, emissions vary much more than in continuous use BPH, and add-on control costs would be even more economically infeasible than for a continuously operating BPH.

Response: The EPA acknowledges this comment.

Commenter Name: Kenneth Anderson

Commenter Affiliation: Ameren Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3487-A1

Comment Excerpt Number: 4

Comment: Ameren has several auxiliary boilers located at Ameren facilities for use when all facility electric generating units are offline at the same time or when supplemental steam is required. These units are operated erratically and could easily exceed the current limited use criteria of 876 hours. For example, Ameren has recently encountered this issue during installation of flue gas desulfurization systems at one of our facilities. Because the outages for the tying in of two FGD systems at two units at one facility occurred over the course of several months, the auxiliary boiler at that facility was required to operate more than 876 hours over a 12 month period. Conversely, this auxiliary boiler never approached a capacity factor of 10 % despite operating for up to 1,950 hours during a 12 month period. With the promulgation of both the EGU MACT rule and the Cross State Air Pollution Rule we expect this situation to occur more frequently as changes to Ameren's generating fleet are made to comply with these new rules. Without a change to the definition of limited use boilers, Ameren's auxiliary boilers may have to forgo limited use status in order to accommodate steam needs at their facilities while other units at their facility upgrade pollution control devices to meet the new EGU MACT or other newly promulgated federal standards. This will result in significant costs with little air quality benefit.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3500-A1, excerpt 7 for discussion on changes in load and its impact on capacity factor versus operating hours, and the response to comment EPA-HQ-OAR-2002-0058-3520-A1, excerpt 2 for discussion on the additional costs which would arise without a limited use category.

Commenter Name: Robert Cleaves

Commenter Affiliation: Biomass Power Association (BPA) and California Biomass Energy

Alliance (CBEA)

Document Control Number: EPA-HQ-OAR-2002-0058-3489-A1

Comment Excerpt Number: 3

Comment: EPA appropriately established a separate subcategory for limited use boilers, and work practices as the mechanism for compliance. However, we think that the limited use boiler definition should be tied to 10 percent of annual capacity utilization (MMBTU/year) rather than 10 percent of the annual operating hours. Boilers running at low loads are limiting their use but according to EPA definition would be consuming capacity as though they were running at full load.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3500-A1, excerpt 7 for discussion on changes in load and its impact on capacity factor versus operating hours.

Commenter Name: Kenneth Anderson

Commenter Affiliation: Ameren Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3487-A1

Comment Excerpt Number: 3

Comment: By changing from an annual hourly limitation to a capacity limitation EPA would then be consistent with the recently signed Utility MACT rule (MATS) (77 Fed Reg. p. 9304 (February 16, 2012)). EPA used the following rational for the use of capacity factor for limited use oil EGU boilers in the MATS rule: "

... Because the operation of these units is infrequent and unpredictable, performing testing to demonstrate that emission limits are being met requires the sources to be scheduled to be operated merely for the purpose of performing testing. We realize that similar situations occurred in the gathering of emissions data through the 2010 /CR. However, unlike the case of one-time testing on a limited number of these units, such testing would be mandatory on a yearly basis for all of the EGUs upon the effective date of the final rule. Because requiring testing under this rule would in many cases require operators of these EGUs to schedule operation of these EGUs at times they would not otherwise run, it would result in both extra cost related to the testing as well as extra emissions; therefore, the Agency believes that it is technically and economically impracticable to monitor emissions for these EGUs, and that they should be subject to work practice standards that would not require emissions monitoring. "

The same is true for industrial boilers. EPA uses this same rational for industrial boilers:

" ... EPA agrees that a subcategory for limited use units is appropriate for many of the reasons stated by the commenters. The fact that the nature of these units is such that they operate for unpredictable periods of time, limited hours, and at less than full load in many cases has lead EPA to determine that limited use units are a unique class of unit based on the unique way in which they are used and EPA is including a subcategory for these units in the final rule. The unpredictable operation of this class of units makes emission testing for the suite of pollutants being regulated impracticable. In order to test the units, they would need to be operated specifically to conduct the emissions testing because the nature and duration of their use does not allow for the required emissions testing. As commenters noted, such testing and operation of

*the unit when it is not needed is also economically impracticable, and would lead to increased emissions and combustion of fuel that would not otherwise be combusted. "*²

In the final EGU MACT (MATS) rule EPA justifies an 8% capacity factor for limited use units and work practice standards under CAA 112(h). It makes no sense that Industrial oil/gas fired boilers that are generally less than 250 mmbtu/hr and orders of magnitude smaller than EGU boilers be held to a higher standard than utility oil fired EGU boilers. Since EPA has justified work practice standards based on unit capacity factor for EGUs under CAA section 112(h) as part of the MATS rule it seems reasonable that the same can and should be done for industrial oil fired boilers as demonstrated by EPA's comments above.

[Footnotes]

(1) 77 Fed Reg. p. 9304 (February 16, 2012))

(2) 76 Fed Reg. p. 15634 (March 21, 2011))

Response: See the response to comment EPA-HQ-OAR-2002-0058-3500-A1, excerpt 7 regarding the definition of limited use with capacity factor instead of operating hours, and the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 2 for discussion on capacity factor applicability to work practice standards. See the response to comment EPA-HQ-OAR-2002-0058-3495-A1, excerpt 8 for discussion on an 8 percent capacity factor.

Commenter Name: Lee Zeugin and Lauren Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1

Comment Excerpt Number: 5

Comment: UARG supports EPA's inclusion of a limited use subcategory in the final rule as well as its decision to establish work practice standards for that subcategory. As UARG noted in its comments on the 2010 proposed rule, electric utilities operate auxiliary boilers that are subject to Subpart DDDDD because those boilers do not generate steam used to produce electricity. Auxiliary boilers operate infrequently, normally during plant startups. They combust either natural gas or distillate fuel. As a result, HAP emissions from those units are exceedingly low and do not pose any risk to public health.

Response: The EPA thanks the commenter for their support. See the response to comment EPA-HQ-OAR-2002-0058-3495-A1, excerpt 8 for discussion on the Utility MACT and its use of capacity factor in relation to the boiler rule.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 75

Comment: EPA has taken a capacity factor approach in the recently finalized MATS rule, establishing a subcategory for limited use liquid-fired units with an 8 percent capacity factor (limited-use liquid oil-fired subcategory means an oil-fired electric utility steam generating unit

with an annual capacity factor of less than 8 percent of its maximum or nameplate heat input, whichever is greater, averaged over a 24-month block contiguous period).⁴¹

[Footnote 41: See 40 CFR 63.10000 and 63.10042.]

Response: See the response to comment EPA-HQ-OAR-2002-0058-3495-A1, excerpt 8 for discussion on the Utility MACT and its use of capacity factor in relation to the boiler rule.

Commenter Name: William C. Herz

Commenter Affiliation: The Fertilizer Institute (TFI)

Document Control Number: EPA-HQ-OAR-2002-0058-3448-A1

Comment Excerpt Number: 10

Comment: EPA requests comment on the limited-use subcategory. Most ammonia plants have a <50 MMBtu/hr fired start-up heater which is only used during the initial cold start-up of an ammonia converter. The start-up heater is required to be fired every turnaround, which could be once in five years. It is not uncommon for the start-up heater to remain idle for three years or more.

As defined in the Proposed Rule, several TFI members have start-up heaters that would meet the definition of a "limited-use process heater" since the heaters are less than 10 MMBtu/hr and limited in hours of operation below the threshold of 876 hours of operation. However, some TFI members have permitted heaters that, based on emissions limits, are permitted to operate 8,760 hours per year.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3682-A2, excerpt 7 regarding removal of language requiring a federally enforceable limit of 876 operating hours.

Commenter Name: William C. Herz

Commenter Affiliation: The Fertilizer Institute (TFI)

Document Control Number: EPA-HQ-OAR-2002-0058-3448-A1

Comment Excerpt Number: 13

Comment: For those units permitted to operate for greater than 876 hrs/yr based on a federally enforceable emissions limit, TFI requests that EPA allow such units to be deemed in the limited-use subcategory when they document the actual hours of operation per year and use that as the basis for determining the feasibility/need for a periodic tune-up.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3682-A2, excerpt 7 regarding removal of language requiring a federally enforceable limit of 876 operating hours.

Commenter Name: William C. Herz

Commenter Affiliation: The Fertilizer Institute (TFI)

Document Control Number: EPA-HQ-OAR-2002-0058-3448-A1

Comment Excerpt Number: 11

Comment: TFI requests that EPA provide a categorical exemption from the regulation for any boiler or process heater that operates less than 100 hrs/yr and has a federally enforceable limit for hours of operation. This could be done either within the definition of "limited-use boiler or process heater" (proposed 40 C.F.R. § 63.7575) or could be added to the list of boilers and process heaters not subject to the rulemaking (proposed 40 C.F.R. § 63.7491). There is precedent for this approach.

Response: The EPA disagrees that sources that operate less than 100 hours per year should be categorically exempt from the rule. While these units emit much lower amounts of the regulated pollutants on a per-source basis, the aggregate emissions from all sources that comprise this subset can have a significant impact on the environment. Moreover, these sources are part of the listed source category regulated in today's action, and the commenter has not explained how the Clean Air Act authorizes the EPA to exempt such sources.

Commenter Name: Mark Thoma, Principal, Environmental Services Department

Commenter Affiliation: Otter Tail Power Company

Document Control Number: EPA-HQ-OAR-2002-0058-3436-A1

Comment Excerpt Number: 3

Comment: At a minimum, if EPA is unwilling to change the limited-use subcategory to a 10% capacity factor basis, Otter Tail requests that the proposed definition of a limited-use boiler be changed to be based on a longer-term average of operating hours, such as three years¹. This would help account for unique circumstances that Otter Tail is faced with at one electric generating facility where we will install selective catalytic reduction equipment, flue-gas desulfurization equipment, and a baghouse to comply with a Regional Haze State Implementation Plan. This will require a 3-4 month outage whereby the auxiliary boiler will potentially need to be operated throughout the outage period to prevent equipment freeze up. Since the auxiliary boiler operation may exceed 876 hours during that outage, in absence of changing the proposed rule definition, Otter Tail would be faced with having to meet significantly more stringent standards for an extremely rare event. This unique circumstance will likely be faced by electric generating facilities in northern climates that will need to take extended outages to install pollution control equipment for compliance with upcoming EPA rulemakings (such as the electric utility MATS, Cross-State Air Pollution Rule, and the Regional Haze Rule).

[Footnote]

(1) The revised definition in §63.7575 would then read: "*Limited-use boiler or process heater* means any boiler or process heater that burns any amount of solid, liquid, or gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and has a federally enforceable limit of no more than 876 hours per three-year average of operation."

Response: The definition of the limited use subcategory has been revised in the final rule to be based on a 10 percent capacity factor approach, and the annual operational hour threshold has been removed.

Commenter Name: Eric Guelker, Alliant Energy Corporate Services, Inc.
Commenter Affiliation: Interstate Power and Light Company (IPL) and Wisconsin Power and Light Company (WPL), Alliant Energy Corp.
Document Control Number: EPA-HQ-OAR-2002-0058-3492-A1
Comment Excerpt Number: 10

Comment: Alliant Energy supports EPA's determination to include a "limited-use" subcategory for boilers and process heaters. Power plants maintain auxiliary boilers and process heaters that are used infrequently and run only in limited circumstances, but must be available to ensure reliability of electricity production. These units result in minimal emissions making the application of air pollution controls or other measures to reduce emissions cost-prohibitive. Therefore, it is critical that the EPA retain the limited use subcategory in the final reconsidered rule. Most importantly, the allowed 876 hours per year of operation should not be decreased in the final reconsidered rule.

Response: The EPA thanks the commenter for their support of the limited use subcategory. The definition of the limited use subcategory has been revised in the final rule to be based on a 10 percent capacity factor, and the annual operating hour restriction has been removed. The EPA believes this provides sources with additional flexibility in demonstrating limited use subcategorization.

Commenter Name: J. Michael Geers
Commenter Affiliation: Duke Energy
Document Control Number: EPA-HQ-OAR-2002-0058-3543-A1
Comment Excerpt Number: 22

Comment: Duke Energy believes that using capacity factor instead of a limit based on hours of operation is a reasonable approach for defining this boiler category. From a compliance perspective, monitoring hours of operation in a boiler is more of an administrative challenge than it is for IC engines. While IC engines can utilize a non-resettable hour meter requirement, this concept is not easily adapted to a boiler because of the different firing systems. For boilers, particularly those utilizing gas and/or oil, it is significantly easier to record total fuel consumed and compare that value with the unit's maximum potential operation based on 8760 hours of operation at maximum capacity.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3520-A1, excerpt 4 regarding the ease of monitoring heat input.

Commenter Name: James M Parker
Commenter Affiliation: PPL Montana, LLC
Document Control Number: EPA-HQ-OAR-2002-0058-3528-A1
Comment Excerpt Number: 1

Comment: EPA Should Define an "Idled Boiler" Subcategory for Boilers that Are Currently Idled, But May Be Needed at a Future Date.

EPA should define an additional subcategory for boilers that are currently idled and consequently do not operate routinely. EPA should exempt these boilers from all requirements of the Proposal until these boilers are re-started, at which time they would be required to comply with the appropriate regulations.

At one of our facilities, PPL Montana has boilers that are designed for startup and heating in emergency situations, when the facility is in a "black start" condition, but these boilers are not and have not operated routinely for many years since the contingent "black start" condition has not occurred in that time period. Yet, we (and possibly other facilities in the same situation) would have need for these boilers should the "black start" condition occur at some future date. If that need were to occur, PPL Montana would re-start the boilers under current regulatory requirements.

Since the boilers do not operate routinely, the required tune-ups in the Proposal would actually result in more emissions than are currently being experienced from these boilers. Thus, EPA should recognize a subcategory for idled boilers that will only require the facility to operate the boiler in compliance with applicable requirements at the time of future re-start.

Response: We disagree that a separate subcategory needs to be created for idled boilers. However, we have revised section 63.7510 of the final rule to add subparagraph (j) that addresses the commenter's concerns. Subparagraph (j) applies to units that have not operated (idled) indicating that the tune-up requirement need not be conducted until the unit is re-started.

Commenter Name: Stuart A. Clark

Commenter Affiliation: State of Washington Department of Ecology

Document Control Number: EPA-HQ-OAR-2002-0058-3665-A2

Comment Excerpt Number: 4

Comment: We are disappointed that EPA did not harmonize the CISWI and Major Source Boiler MACT requirements as they apply to units that may operate periodically as part of its final rule. Washington State appreciates the complexity involved in establishing NESHAP standards over the varied range of source types and sizes addressed by these proposed rules. EPA's efforts to gather additional data, carefully consider that data and public comments is apparent. These efforts have resulted in a set of rules that reduce the burden on industry, clarify and streamline the rules to facilitate smoother implementation and still maintain public health protection.

Response: Comments pertaining to the harmonization of the CISWI and Major Source Boiler and Process Heater NESHAPs are outside the scope of this comment response document.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 6

Comment: We offer the following additional points in support of a capacity factor approach:

- Limited use units are likely to be operated infrequently. Many will be in cold-standby until their operation is warranted. This requires, typically, a 2 to 4 hour startup, depending on the size of the boiler, etc. During the start-up period, the boiler is not producing steam for use in a turbine or by heating/process load customers. In general, fuel will be burned for a short period of time (5 to 10 minutes) a couple of times an hour, then the boiler “buttoned up” in between to keep the heat in to allow the metal to slowly warm in order to prevent metal stress. *As currently defined, each hour of start-up would constitute an “operating hour”, decreasing the available hours for a limited use boiler to operate.*
- From a practical compliance perspective, monitoring hours of operation is an administrative challenge. It is more effective in a permit for a source to accept a fuel consumption limit, and also easier to monitor electronically. While IC engines are equipped with a non-resettable hour meter, the same is not true for boilers. In addition, monitoring fuel usage is already required in the Boiler MACT and other permit requirements, so this requirement would not create the additional burden that monitoring hours of operation would.
- 40 CFR 75, Appendix E, provides relief from the burdensome NOx continuous emissions monitoring requirements of the Acid Rain Program for affected units that limit the capacity factor to less than 10% on a 3-year average. This is an example of where EPA implemented a work practice standard based on a capacity factor instead of the standard requirement.
- In the RICE NESHAP, EPA implemented a work practice standard for emergency and limited use units.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3500-A1, excerpt 7 regarding inclusion of the capacity factor in the limited use definition, the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 2 for discussion on capacity factor applicability to work practice standards, and the response to comment EPA-HQ-OAR-2002-0058-3520-A1, excerpt 4 regarding the ease of monitoring heat input. Comments related to capacity factors or work standards in other rules or subparts (e.g., 40 CFR Part 75 Appendix E, or 40 CFR Part 63 Subpart ZZZZ) are outside the scope of this comment response document.

Commenter Name: John C. Hendricks

Commenter Affiliation: American Electric Power (AEP)

Document Control Number: EPA-HQ-OAR-2002-0058-3455-A1

Comment Excerpt Number: 1

Comment: American Electric Power (AEP) appreciates EPA's efforts made to correct technical deficiencies in the development of the IB Boiler MACT Rule. AEP specifically supports the addition of the definition of and the associated provisions for limited use boilers to allow these units to operate effectively without the expensive burden of unnecessary continuous monitoring, recordkeeping and reporting. Within AEP, these units are ancillary to the main operations at the electric utility facilities and with proper maintenance, will meet the goals of the program without undue monitoring and reporting requirements.

Response: The EPA thanks the commenter for their support.

Commenter Name: Lenny Dupuis
Commenter Affiliation: Dominion Resources Services, Inc.
Document Control Number: EPA-HQ-OAR-2002-0058-3486-A1
Comment Excerpt Number: 1

Comment: We support the retention of the limited use subcategory for oil-fired units established in the March 2011 final rule that will allow such units to meet work practice standards in lieu of emission standards.

Response: The EPA thanks the commenter for their support.

Commenter Name: Timothy Serie
Commenter Affiliation: American Coatings Association (ACA)
Document Control Number: EPA-HQ-OAR-2002-0058-3502-A1
Comment Excerpt Number: 7

Comment: ACA generally supports the following proposed changes in the Boiler MACT rule:

Establishment of a subcategory and separate standards for limited-use units that operate for shorter periods of time

Response: The EPA thanks the commenter for their support.

Commenter Name: Chris M. Hobson
Commenter Affiliation: Southern Company
Document Control Number: EPA-HQ-OAR-2002-0058-3520-A1
Comment Excerpt Number: 1

Comment: Southern Company supports EPA's proposed decision to establish a subcategory for limited use units instead of requiring these units to meet stringent emission standards. Clean Air Act (CAA) § 112(h) provides that the EPA Administrator may promulgate work practice standards in lieu of emission limits if "it is not feasible in the judgment of the Administrator to prescribe or enforce an emission standard for control of a hazardous air pollutant . . ." 42 U.S.C. § 7412(h)(1). The Act further clarifies that this provision can be used if "the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations." Id. at § 7412(h)(2)(B). As EPA correctly notes, "the unpredictable operation of this class of units makes emission testing for the suite of pollutants being regulated impracticable."¹

[Footnote]

(1) 76 Fed. Reg. at 15634

Response: The EPA thanks the commenter for their support.

Commenter Name: Matthew Todd
Commenter Affiliation: American Petroleum Institute (API) and American Fuel and

Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 41

Comment: We strongly support EPA's conclusion that the CAA 112(h) criteria are met and therefore design, equipment, work practice, or operational requirements are the appropriate and legal means of meeting the requirements of CAA section 112(d)(2) for D/F emissions, for the Gas 1 and Limited-Use subcategories and for smaller boilers and process heaters (i.e., <10 MMBTU/hr).

Response: The EPA thanks the commenter for their support.

Commenter Name: Douglas A. McWilliams

Commenter Affiliation: American Municipal Power

Document Control Number: EPA-HQ-OAR-2002-0058-3685-A2

Comment Excerpt Number: 33

Comment: A Limited Use Subcategory is Appropriate and Should Be Maintained

EPA requested comment on final adoption of the limited use subcategory. AMP supports a limited use subcategory for all of the reasons stated in the 2010 AMP Comments. EPA was justified in creating this subcategory because these units have a distinct operating mode and come online only during special circumstances (e.g., emergencies, primary boiler outage). This distinct operating mode results in unplanned and infrequent operation that is not amenable to scheduled testing and monitoring, making emission limits infeasible for these units.

Response: The EPA thanks the commenter for their support.

Commenter Name: Heather Parent

Commenter Affiliation: Maine Department of Environmental Protection

Document Control Number: EPA-HQ-OAR-2002-0058-3691-A2

Comment Excerpt Number: 2

Comment: Maine DEP supports EPA's proposed limited-use subcategory for units that operate less than 10% of the year and the reduced requirements that have been proposed for these units.

Response: The EPA thanks the commenter for their support.

7B. Solid Fuel for Hg and HCl

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 18

Comment: Coal-fired boilers are fundamentally different than biomass units. For example, a boiler designed to burn coal as its primary fuel cannot burn biomass without experiencing

unacceptable performance degradation, including fouling and loss of fan capacity. This is due to the differing chemical constituents of the ash, which influence fouling characteristics (increased fouling potential with biomass), and the significantly higher moisture in biomass versus coal, which increases volumetric flow rate and thereby limits fan capacity with biomass. A pulverized coal boiler with no grate will not be able to accommodate other solid fuels. Additionally, the boiler backpass (convection section) configuration is designed specifically for the fuel type. This is another reason a coal boiler cannot burn significant amounts of biomass, and vice-versa. CIBO produced a 2003 document entitled —Energy Efficiency and Industrial Boiler Efficiency: An Industry Perspective. The following excerpts from that document provide further evidence that coal and biomass boilers truly are different types of boilers: *Wood and biomass are solid fuels with both high hydrogen to carbon and high moisture content (greater than 40%). Because of energy loss due to moisture from the combustion of hydrogen and conversion of moisture to vapor (1000 Btu per pound), it is very difficult to obtain efficiencies, either MCR or annual average, equal to or approaching those of natural gas, never mind, oil or coal. A very good annual average efficiency for a wood or biomass unit may be in the 60% range. While fuel property variations may be better than coal, these variations usually occur in the moisture content with a direct and major impact on boiler efficiency. (page 3)*

Fuel characteristics determine the design of a particular unit. Fuel changes, especially in hydrogen and moisture content outside the range of 1 or 2% for natural gas, 3 to 5% for oil and 10% for coal and other solid fuels, will have an impact on efficiency, both MCR and annual average. When fuels are switched, the interaction of the new fuel and the boiler often produces negative impacts on either the load or the boiler efficiency. These effects often are amplified because of limitations encountered in specific areas of the boiler where these adverse interactions occur. (page 3)

Fuel type and availability has a major effect. Fuels with high heating values, high carbon to hydrogen ratios, and low moisture content can yield efficiencies up to 25% higher than fuels that have low heating values, low carbon to hydrogen ratios, and high moisture contents. A rule of thumb for the efficiency hierarchy in descending order is coal, heavy fuel oil, light fuel oil, natural gas, and biomass. From these rankings, it is obvious that fuel availability plays a major role. (page 11)

Response: The EPA acknowledges that not all solid fuel units are designed to combust biomass. As stated in the preamble to the 2010 proposed rule (75 FR 32017), the design of the boiler or process heater, which is dependent in part on the type of fuel being burned, impacts the degree of combustion. However, the formation of fuel-dependent HAP (metals, mercury, and acid gases) is dependent upon the composition of the fuel. These fuel-dependent HAP emissions generally can be controlled by either changing the fuel property before combustion or by removing the HAP from the flue gas after combustion. Based on information contained in the survey database in the docket, similar technologies for controlling these fuel-related HAP are used on both coal units and biomass units. The existing MACT floor emission limitations for Hg and HCl for solid fuel boilers were calculated from the emissions from both dedicated coal and dedicated biomass combustion, and the variability between the two fuels is factored into the calculation of the 99% UPL. For this reason, the EPA believes that the floor has been established at a level that is representative of low emitting coal and biomass sources in the top 12 percent of units.

On the other hand, organic HAP are formed from incomplete combustion and are influenced by the design, which is influenced by the type of fuel, and operation of the unit. Organic HAP (which we use CO as a surrogate) are combustion-related and, therefore, a boiler type (e.g., stoker) designed for biomass will have a different emission characteristics which influence the feasibility or effectiveness of controls than a similar boiler type designed for coal.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 16

Comment: *EPA Should Establish Separate Subcategories for Hg and HCl for Coal and Biomass*

In the preamble to this Reconsideration Proposal, EPA solicited comments on its decision in the Final Boiler Rule to combine biomass and coal-fired units into one subcategory for the fuel-based HAPs (PM (as a surrogate for non-Hg metals), HCl, and Hg). 76 Fed. Reg. 80607. Previously, in the 2010 Proposed Boiler Rule, EPA had proposed separate standards for biomass and coal-fired units. To establish CO standards, EPA further subdivided coal into stoker, pulverized coal, and fluidized bed, and subdivided biomass into stokers, fluidized beds, suspension burners/Dutch ovens, and fuel cells. The 2010 Proposed Boiler Rule placed certain combination-type units designed to burn both biomass and coal in the coal subcategory if they burned at least 10 percent coal on a heat input basis as an annual average. In justifying these subcategories, EPA recognized the differences between biomass and coal-fired units. *See* 75 Fed. Reg. 32017 (June 4, 2010).

Response: See the response to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 18.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 17

Comment: In the Final Boiler Rule, EPA grouped coal-fired boilers with biomass-fired boilers for fuel-based pollutants (Hg, HCl and PM) into a single solid fuel subcategory. *See* 76 Fed. Reg. 15612, Table 1. In neither the Final Boiler Rule MACT Floor memo nor the Final Boiler Rule preamble explaining its rationale for selecting the recommended approach (one solid fuel subcategory) over the alternative approach (to subcategorize coal and biomass) for fuel based pollutants has EPA discussed its approach. Finally, no mention is made of this alternative in the Reconsideration Proposal. The solid fuel grouping is ripe for reconsideration because it appeared for the first time in the Final Boiler Rule, and hence the public did not have an opportunity to comment on it. EPA has offered no further explanation of its decision in the record to the reconsideration proposal.

Response: We agree that the solid fuel grouping appeared for the first time in the Final 2011 Boiler Rule, but disagree that the public did not have an opportunity to comment on it. In response to the variety of comments received on the 2010 proposed rule regarding combination

fuel boilers, the EPA revised the subcategories (see 76 FR 15636) in order to simplify implementation, improve the flexibility of units in establishing and changing fuel mixtures, promote combustion of cleaner fuels, and provide MACT standards that are enforceable and consistent with the requirements of section 112. For combined fuel units that combust solid fuels, due to the many potential combinations and percentages of solid fuels that are or can be combusted, for the fuel-based pollutants, the EPA selected the option of combining the subcategories for solid fuels into a single solid fuel subcategory. For the fuel-based pollutants, this alleviated the concerns regarding changes in fuel mixtures, promotion of combustion of dirtier fuels, and the implementation and compliance concerns. See the response to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 18.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 20

Comment: ACC understands that there are certain "combination" units that are designed to be able to burn both biomass and coal. If EPA does separate coal boilers from biomass boilers to set PM, Hg, and HCl emission limits, as ACC strongly urges the Agency to do, a problem will surface concerning certain combination boilers specifically designed to burn varying percentages of coal, biomass, and other solid fuels such as tire-derived fuel and biomass residuals. The current biomass subcategory definition includes any such unit that burns greater than 10 percent biomass on an annual heat input basis as a "unit designed to burn biomass/bio-based solids." EPA did this so that the combination units would be subject to CO limits derived from pure biomass units, since combustion of biomass produces a CO emissions profile that is different from combustion of coal. As EPA describes in the Final Boiler Rule preamble, it attempts to resolve the combination boiler dilemma by combining all solid fuel boilers into one subcategory for fuel based pollutants:

"For combined fuel units that combust solid fuels, due to the many potential combinations and percentages of solid fuels that are or can be combusted, for the fuel-based pollutants, EPA selected the option of combining the subcategories for solid fuels into a single solid fuel subcategory. For the fuel-based pollutants, this alleviates the concerns regarding changes in fuel mixtures, promotion of combustion of dirtier fuels, and the implementation and compliance concerns."(76 Fed. Reg. 15636)

ACC maintains that this change in subcategories, designed primarily to address combination units, is inappropriate for coal only-fired units because, as discussed above, coal-fired boilers are different types of boilers than biomass boilers and have very different emission profiles due both to their design and the fuels they are designed to combust.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 18.

Commenter Name: Vickie Woods

Commenter Affiliation: Division of Air Quality, North Carolina Department of Environment and Natural Resources (NCDENR)

Document Control Number: EPA-HQ-OAR-2002-0058-3663-A2

Comment Excerpt Number: 7

Comment: We also support EPA for adding a solid fuel subcategory to the final rule that replaces previously proposed separate subcategories for units designed to burn solid fossil-based fuels and units designed to burn solid bio-based fuels.

Response: The EPA thanks the commenter for their support. See the response to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 18 for discussion.

Commenter Name: Robin Mills Ridgway

Commenter Affiliation: Purdue University

Document Control Number: EPA-HQ-OAR-2002-0058-3668-A2

Comment Excerpt Number: 11

Comment: In the preamble to the December 2011 proposed rule (76 FR 80607), EPA solicits comments on its decision in the March 2011 final rule to combine biomass and coal-fired units into one subcategory for the fuel-based HAPs (PM [as a surrogate for non-Hg metals], HCl, and Hg). EPA had proposed separate standards for biomass and coal-fired units in the June 2010 proposed rule. To establish CO standards, EPA further subdivided coal into stoker, pulverized coal, and fluidized bed, and subdivided biomass into stokers, fluidized beds, suspension burners/Dutch ovens, and fuel cells. The June 2010 proposed rule placed certain combination-type units designed to burn both biomass and coal in the coal subcategory if they burned at least 10 percent coal on a heat input basis as an annual average. In justifying these subcategories, EPA recognized the differences between biomass and coal-fired units. *Id.* at 32017.

In the March 2011 final rule, EPA grouped coal fired boilers with biomass fired boilers for fuel based pollutants (Hg, HCl and PM) into a single solid fuel subcategory. See 76 Fed. Reg. 15612, Table 1. EPA has no discussion either in the March 2011 final rule MACT Floor memo or the March 2011 final rule preamble explaining its rationale for selecting the recommended approach (one solid fuel subcategory) over the alternative approach (to subcategorize coal and biomass) for fuel based pollutants. Finally, no mention is made of this alternative in the December 2011 Proposal. The solid fuel grouping is ripe for reconsideration because it appeared for the first time in the March 2011 final rule, and hence the public did not have an opportunity to comment on it. EPA has offered no further explanation of its decision in the record to the reconsideration proposal.

Response: See the responses to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 18 and EPA-HQ-OAR-2002-0058, excerpt 17.

Commenter Name: Robin Mills Ridgway

Commenter Affiliation: Purdue University

Document Control Number: EPA-HQ-OAR-2002-0058-3668-A2

Comment Excerpt Number: 12

Comment: Coal-fired boilers are fundamentally different than biomass units. For example, a boiler designed to burn coal as its primary fuel cannot burn biomass without experiencing

unacceptable performance degradation, including fouling and loss of fan capacity. This is due to the differing chemical constituents of the ash, which influence fouling characteristics (increased fouling potential with biomass), and the significantly higher moisture in biomass versus coal, which increases volumetric flow rate and thereby limits fan capacity with biomass. A pulverized coal boiler with no grate will not be able to accommodate other solid fuels. Additionally, the boiler backpass (convection section) configuration is designed specifically for the fuel type. This is another reason a coal boiler cannot burn significant amounts of biomass, and vice-versa. The Council of Industrial Boilers (CIBO), an organization that represents both designers/manufacturers of boilers as well as boiler owners/operators, produced a document in 2003 entitled "Energy Efficiency and Industrial Boiler Efficiency: An Industry Perspective". The following excerpts from that document provide further evidence that coal and biomass boilers truly are different types of boilers:

Wood and biomass are solid fuels with both high hydrogen to carbon and high moisture content (greater than 40%). Because of energy loss due to moisture from the combustion of hydrogen and conversion of moisture to vapor (1000 Btu per pound), it is very difficult to obtain efficiencies, either MCR or annual average, equal to or approaching those of natural gas, never mind, oil or coal. A very good annual average efficiency for a wood or biomass unit may be in the 60% range. While fuel property variations may be better than coal, these variations usually occur in the moisture content with a direct and major impact on boiler efficiency. (page 3)

Fuel characteristics determine the design of a particular unit. Fuel changes, especially in hydrogen and moisture content outside the range of 1 or 2% for natural gas, 3 to 5% for oil and 10% for coal and other solid fuels, will have an impact on efficiency, both MCR and annual average. When fuels are switched, the interaction of the new fuel and the boiler often produces negative impacts on either the load or the boiler efficiency. These effects often are amplified because of limitations encountered in specific areas of the boiler where these adverse interactions occur. (page 3)

Fuel type and availability has a major effect. Fuels with high heating values, high carbon to hydrogen ratios, and low moisture content can yield efficiencies up to 25% higher than fuels that have low heating values, low carbon to hydrogen ratios, and high moisture contents. A rule of thumb for the efficiency hierarchy in descending order is coal, heavy fuel oil, light fuel oil, natural gas, and biomass. From these rankings, it is obvious that fuel availability plays a major role. (page 11)

Response: See the response to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 18.

Commenter Name: Steve Gossett

Commenter Affiliation: Eastman Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3669-A2

Comment Excerpt Number: 4

Comment: Separate subcategories for biomass and coal-fired boilers are appropriate when setting particulate matter, hydrogen chloride, and mercury emission standards.

In the proposed rule (June 4, 2010), EPA set separate standards for biomass and coal-fired units. To establish CO and D/F standards, EPA further subdivided coal into stoker, pulverized coal,

and fluidized bed, and the Agency subdivided biomass into stokers, fluidized beds, suspension burners/Dutch ovens, and fuel cells. The proposed rule placed certain combination-type units designed to burn both biomass and coal in the coal subcategory if they burn at least 10 percent coal on a heat input basis as an annual average. In justifying these subcategories, EPA properly recognized the differences between biomass, coal, liquid, and gas-fired units. *Id.* at 32017.

In the Final Rule, and without any notice to the regulated community that it was going to do so, EPA grouped coal fired boilers with biomass fired boilers for fuel based pollutants (Hg, HCl and PM) into a single solid fuel subcategory. *See*, Final Rule, 76 Fed. Reg. at 15612, Table 1. We note that EPA has no discussion either in the Final Rule MACT Floor memo or the Final Rule preamble explaining its rationale for selecting the recommended approach over the alternative approach, which was to subcategorize coal and biomass. EPA does not even mention the alternative in its narrative. Finally, no mention is made of this alternative in the Reconsideration Proposal. This grouping is ripe for reconsideration because it appeared for the first time in the Final Rule, and hence the public did not have an opportunity to comment upon it. We recognize that EPA is reconsidering this issue but has offered no further explanation of its decision in the record to the reconsideration proposal.

Response: See the responses to comments EPA-HQ-OAR-2002-0058-3510-A1, excerpt 18 and EPA-HQ-OAR-2002-0058-3510-A1, excerpt 17 .

Commenter Name: Steve Gossett

Commenter Affiliation: Eastman Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3669-A2

Comment Excerpt Number: 5

Comment: Coal fired boilers are fundamentally different than biomass boilers. Eastman has conducted extensive engineering analysis of its fleet of coal boilers in an effort to quantify how much, if any, biomass fuel could be burned in order to prepare for future greenhouse gas regulations and/or renewable fuel portfolio standards. One dimension of this analysis engaged the boiler OEM to understand what fundamentally distinguishes a coal unit from a biomass unit. Eastman learned that from the boiler design engineer's perspective, coal and biomass units are fundamentally and irreconcilably different, in much the same sense that diesel fuel is incompatible with a gasoline engine, and vice versa. Superficially, coal and biomass units share similar features (e.g. stoker units for both coal and biomass firing can utilize spreader stokers and traveling grates; waterwalls and refractory in the furnace; pendant and platen superheaters; economizers and air preheaters; etc.). But from the boiler designers perspective, the sizing of the furnace, spacing of the heat transfer elements, fan requirements, and fuel handling equipment are fundamentally different. Most fundamental is the size (plan area) and volume of the furnace, which is primarily a function of the rank of the fuel. Consider Alstom Power's Figure 3-2 (Effect of coal rank on sizing of a pulverized-fuel furnace) from their 2009 edition of Clean Combustion Technologies. That figure shows how both the plan area and the overall furnace height changes with the rank of fuel. As rank changes from low (lignites) to high (bituminous) fuels, the plan area and total furnace volume decrease dramatically, as shown below in Table 1 {see submittal for Table 1}.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 18.

Commenter Name: Steve Gossett
Commenter Affiliation: Eastman Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3669-A2
Comment Excerpt Number: 6

Comment: Table 1 [of the submittal] clearly shows that from a design perspective, the rank of the fuel is fundamental to the boiler's basic structure. And as EPA is well aware, once the plan area and height of a boiler are fixed at the design stage, changes to these fundamental criteria cannot be made once construction has started any more than a gasoline engine could be modified to burn diesel fuel.

And if the boiler's fundamental design is predicated on rank, a full understanding of rank is warranted. Rank can be quantified by various physical and chemical properties (e.g. fixed carbon, volatile matter, moisture, hardness, etc.), but fundamentally the term refers to the energy density of a given fuel. The term is most frequently used in the context of distinguishing between types of coals, such as lignites, sub-bituminous, bituminous and anthracite coals. But rank can be used more generally to compare any number of solid fuels based on their energy density. Refer to Figure 9 (The coalification process) on page 9-4 of Babcock and Wilcox's Steam (41st edition, 2005). That diagram not only shows the cycle that organic fuels proceed through, but also lists fuels of varying rank from wood to peat to coal. As listed in that figure, solids can be viewed through the lens of rank as shown below in Table 2 {see submittal for Table 2}.

As reported by Babcock and Wilcox, and summarized above in Table 2 {see submittal for Table 2}, it can be seen that wood is the lowest of fuel ranks of all the major types of solid fuels used in the US. Taken together, Tables 1 and 2 {of the submittal} illustrate that the most fundamental and unchangeable aspect of a boiler's design (i.e. the plan area and volume) is predicated by the rank of the fuel, and that biomass (wood) is the lowest rank of solid fuel found in the US and is completely distinguished from coals. It can only be concluded that from a boiler designer's and boiler engineer's point of view, biomass boilers are fundamentally and irrevocably different from coal boilers.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 18.

Commenter Name: Steve Gossett
Commenter Affiliation: Eastman Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3669-A2
Comment Excerpt Number: 7

Comment: Another dimension of the biomass firing analysis commissioned by Eastman was to understand the limitations of co-firing biomass in a coal boiler. Recognizing that some amount of biomass co-firing was both technically feasible and commercially demonstrated, the scope of the analysis was to understand how much biomass could be introduced into pulverized coal and stoker coal boilers in Eastman's fleet before significant performance, reliability and/or safety degradation occurred. Eastman learned that even if the significant and capital intensive fuel handling challenges were addressed, the design of the heat transfer surfaces would limit the total amount of biomass that could be fired in the units to less than 20% of the total heat input of the unit. This limit was due to a variety of design issues, including the spacing between the

superheater tubes; the number, location, and allowable wear due to soot blowers; the fouling characteristics of the ash found in biomass fuels; and the impact of the much higher nominal moisture levels in biomass fuels on existing fan capacity. This analysis made clear the fact that coal and biomass boilers are so fundamentally different that it is not possible to freely substitute one fuel for the other unless extensive capital modifications were undertaken, and even then the amount of substitution was very limited. The superficial similarities between some coal and biomass units (e.g. the use of spreader stokers is common in both industrial coal and biomass boilers) are no more fundamental to the design of the boilers than the choice of carburetor versus fuel injection is to an engine. The choice of fuel (e.g. biomass versus coal) is more akin to choosing a diesel engine versus a gasoline engine in a pickup truck: it is a choice that forever and irreconcilably differentiates one from another. Eastman's specific analysis demonstrates that coal units and biomass units are not interchangeable, and EPA should not lump them together as if they were.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 18.

Commenter Name: Steve Gossett

Commenter Affiliation: Eastman Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3669-A2

Comment Excerpt Number: 8

Comment: The amount of biomass that could potentially be fired in any given coal-fired boiler will vary depending on the specific configuration of the unit, but Eastman's conclusions are typical for most coal units. Consider the Council of Industrial Boilers (CIBO), an organization that represents both designers/manufacturers of boilers as well as boiler owners/operators, produced a document in 2003 entitled "Energy Efficiency and Industrial Boiler Efficiency: An Industry Perspective". The following excerpts from that document provide further evidence that coal and biomass boilers truly are different types of boilers:

Wood and biomass are solid fuels with both high hydrogen to carbon and high moisture content (greater than 40%). Because of energy loss due to moisture from the combustion of hydrogen and conversion of moisture to vapor (1000 Btu per pound), it is very difficult to obtain efficiencies, either MCR or annual average, equal to or approaching those of natural gas, never mind, oil or coal. A very good annual average efficiency for a wood or biomass unit may be in the 60% range. While fuel property variations may be better than coal, these variations usually occur in the moisture content with a direct and major impact on boiler efficiency. (page 3)

Fuel characteristics determine the design of a particular unit. Fuel changes, especially in hydrogen and moisture content outside the range of 1 or 2% for natural gas, 3 to 5% for oil and 10% for coal and other solid fuels, will have an impact on efficiency, both MCR and annual average. When fuels are switched, the interaction of the new fuel and the boiler often produces negative impacts on either the load or the boiler efficiency. These effects often are amplified because of limitations encountered in specific areas of the boiler where these adverse interactions occur. (page 3)

Fuel type and availability has a major effect. Fuels with high heating values, high carbon to hydrogen ratios, and low moisture content can yield efficiencies up to 25% higher than fuels that

have low heating values, low carbon to hydrogen ratios, and high moisture contents. A rule of thumb for the efficiency hierarchy in descending order is coal, heavy fuel oil, light fuel oil, natural gas, and biomass. From these rankings, it is obvious that fuel availability plays a major role. (page 11)

Response: See the response to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 18.

Commenter Name: Elizabeth McMeekin

Commenter Affiliation: PPG Industries, Inc

Document Control Number: EPA-HQ-OAR-2002-0058-3778-A1

Comment Excerpt Number: 9

Comment: PPG believes that EPA has the authority to, and should, define separate subcategories for coal and biomass boilers for setting emissions limits for Hg and HCl.

EPA In the preamble to the December 2011 proposed rule (76 Fed. Reg. 80607), EPA solicits comments on its decision in the March 2011 final rule to combine biomass and coal-fired units into one subcategory for the fuel-based HAPs (PM (as a surrogate for non-Hg metals), HCl, and Hg). EPA had proposed separate standards for biomass and coal-fired units in the June 2010 proposed rule. To establish CO standards, EPA further subdivided coal into stoker, pulverized coal, and fluidized bed, and subdivided biomass into stokers, fluidized beds, suspension burners/Dutch ovens, and fuel cells. The June 2010 proposed rule placed certain combination-type units designed to burn both biomass and coal in the coal subcategory if they burned at least 10 percent coal on a heat input basis as an annual average. In justifying these subcategories, EPA recognized the differences between biomass and coal-fired units.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 18.

Commenter Name: Elizabeth McMeekin

Commenter Affiliation: PPG Industries, Inc

Document Control Number: EPA-HQ-OAR-2002-0058-3778-A1

Comment Excerpt Number: 10

Comment: In the March 2011 final rule, EPA grouped coal fired boilers with biomass fired boilers for fuel based pollutants (Hg, HCl and PM) into a single solid fuel subcategory. See 76 Fed. Reg. 15612, Table 1. EPA has no discussion either in the March 2011 final rule MACT Floor memo or the March 2011 final rule preamble explaining its rationale for selecting the recommended approach (one solid fuel subcategory) over the alternative approach (to subcategorize coal and biomass) for fuel based pollutants. Finally, no mention is made of this alternative in the December 2011 Proposal. The solid fuel grouping is ripe for reconsideration because it appeared for the first time in the March 2011 final rule, and hence the public did not have an opportunity to comment on it. EPA has offered no further explanation of its decision in the record to the reconsideration proposal.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 18.

Commenter Name: Elizabeth McMeekin
Commenter Affiliation: PPG Industries, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-3778-A1
Comment Excerpt Number: 12

Comment: Boilers designed to fire coal are fundamentally different than biomass units. A boiler designed to burn coal as its primary fuel cannot burn biomass without experiencing unacceptable performance degradation, and vice-versa, due to the differing chemical constituents of the ash, and the significantly higher moisture in biomass versus coal.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 18.

Commenter Name: Lorraine Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1
Comment Excerpt Number: 19

Comment: ACC notes that EPA acknowledged boiler design considerations driven by fuel type in a similar source category MACT standard – the final MATS Rule. In the MATS, EPA observed significant differences in mercury emissions between boilers burning high-rank and low-rank coals and concluded that the different mercury emission standards were appropriate for these two different fuel types. In the final rule preamble, EPA states:

"...we believed at proposal that the boiler size was the cause of the different Hg emissions characteristics that led us to propose subcategorization, but many commenters indicated that it was not the boiler size but the fact that the EGUs burned a nonagglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of less than 19,305 kJ/kg (8,300 Btu/lb) (low rank virgin coal) that causes the disparity in Hg emissions." (77 Fed. Reg. 9378, February 16, 2012)

EPA goes on to explain that it has the latitude under the Clean Air Act (CAA) to base subcategorization on fuel type:

*"We recognize that some commenters have taken the position that it is unlawful to subcategorize based on factors such as fuel type but nothing in the statute prohibits such an approach and the case law supports this approach to the extent courts have considered subcategorization based on such factors. See *Sierra Club v. Costle*, 657 F. 2d 298, 318-19 (D.C. Cir. 1981) (differing pollutant content of input material can justify a different standard based on subcategorization authority to "distinguish among classes, types and sizes within categories of new sources"). Furthermore, we believe had Congress intended to prohibit the EPA from subcategorizing based on an EGU being designed to use and using a certain material input (e.g., fuel) it would have clearly stated such intent in the CAA. However, we believe the Agency could decline to exercise its discretion to subcategorize even if the potential result would be the prohibition of the use of some materials if the circumstances warranted." *Id.* Similar logic applies in the boiler rulemaking, and should be followed to create separate subcategories for biomass and coal. A boiler designed to burn coal cannot fire biomass and meet its operational requirements, and the resulting HCl, Hg, and PM emissions are dictated by boiler design.*

Response: See response to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 18.

Commenter Name: Robin Mills Ridgway

Commenter Affiliation: Purdue University

Document Control Number: EPA-HQ-OAR-2002-0058-3668-A2

Comment Excerpt Number: 13

Comment: Purdue notes also that EPA acknowledged boiler design considerations driven by fuel type in a similar source category MACT standard – the Utility MACT Rule (February 16, 2012). In the May 3, 2011 Utility MACT proposed rule (see page 25037), EPA observed significant differences in mercury emissions between boilers burning high-rank and low-rank coals and concluded that the different mercury emission standards were appropriate for these two different fuel types. In the final rule preamble (77 FR 9378) EPA states:

"...we believed at proposal that the boiler size was the cause of the different Hg emissions characteristics that led us to propose subcategorization, but many commenters indicated that it was not the boiler size but the fact that the EGUs burned a nonagglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of less than 19,305 kJ/kg (8,300 Btu/lb) (low rank virgin coal) that causes the disparity in Hg emissions."

EPA goes on to explain that it has the latitude under the Clean Air Act to base subcategorization on fuel type:

"We recognize that some commenters have taken the position that it is unlawful to subcategorize based on factors such as fuel type but nothing in the statute prohibits such an approach and the case law supports this approach to the extent courts have considered subcategorization based on such factors. See *Sierra Club v. Costle*, 657 F. 2d 298, 318-19 (D.C. Cir. 1981) (differing pollutant content of input material can justify a different standard based on subcategorization authority to "distinguish among classes, types and sizes within categories of new sources"). Furthermore, we believe had Congress intended to prohibit the EPA from subcategorizing based on an EGU being designed to use and using a certain material input (e.g., fuel) it would have clearly stated such intent in the CAA. However, we believe the Agency could decline to exercise its discretion to subcategorize even if the potential result would be the prohibition of the use of some materials if the circumstances warranted." *Id.*

Similar logic applies in the Industrial Boiler MACT and should be followed to create separate subcategories for biomass and coal. A boiler designed to burn coal cannot fire biomass and meet its operational requirements and the HCl, mercury, and PM emissions are then dictated by this fuel type design choice.

Response: See response to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 18.

Commenter Name: Steve Gossett

Commenter Affiliation: Eastman Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3669-A2

Comment Excerpt Number: 9

Comment: We note also that EPA acknowledged boiler design considerations driven by fuel type in a similar source category MACT standard – the Utility MACT Final Rule (February 16, 2012). In the May 3, 2011 Utility MACT proposed rule (see page 25037), EPA observed significant differences in mercury emissions between boilers burning high-rank and low-rank coals and concluded that the different mercury emission standards were appropriate for these two different fuel types. In the final rule preamble (page 9378), EPA states:

...we believed at proposal that the boiler size was the cause of the different Hg emissions characteristics that led us to propose subcategorization, but many commenters indicated that it was not the boiler size but the fact that the EGUs burned a nonagglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of less than 19,305 kJ/kg (8,300 Btu/lb) (low rank virgin coal) that causes the disparity in Hg emissions.

EPA goes on to explain that it has the latitude under the Clean Air Act to base subcategorization on fuel type: *We recognize that some commenters have taken the position that it is unlawful to subcategorize based on factors such as fuel type but nothing in the statute prohibits such an approach and the case law supports this approach to the extent courts have considered subcategorization based on such factors. See Sierra Club v. Costle, 657 F. 2d 298, 318-19 (D.C. Cir. 1981) (differing pollutant content of input material can justify a different standard based on subcategorization authority to "distinguish among classes, types and sizes within categories of new sources"). Furthermore, we believe had Congress intended to prohibit the EPA from subcategorizing based on an EGU being designed to use and using a certain material input (e.g., fuel) it would have clearly stated such intent in the CAA. However, we believe the Agency could decline to exercise its discretion to subcategorize even if the potential result would be the prohibition of the use of some materials if the circumstances warranted. (page 9379 of the February 16,2012 Federal Register).*

Similar logic applies in the Boiler MACT and should be followed to create separate subcategories for biomass and coal. A coal boiler cannot fire biomass and meet its design requirements, and the HCl, mercury, and PM emissions are then dictated by this fuel type design choice.

Just as in the Utility MACT where EPA recognized that there would be significant differences in mercury emissions between units designed to burn low-rank and high-rank coals, there are significant differences in HCl, mercury, and PM emissions from coal (high rank fuels) and biomass (very low rank fuels) boilers that would also justify this subcategorization.

Response: While the commenter is correct that in the MATS rule, "Coal-fired unit low rank virgin coal" is listed as a subcategory in the tables listing the emissions limits, the subcategory is actually established based on the design of the boiler combusting low rank coal. The definition of the subcategory in MATS is: *Unit designed for low rank virgin coal subcategory means any coal-fired EGU that is designed to burn and that is burning nonagglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of less than 19,305 kJ/kg (8,300 Btu/lb) that is constructed and operates at or near the mine that produces such coal.*" This is consistent with the establishment of subcategories in Boiler MACT. That is, the subcategory is based on the design of the boiler which is based on the type of fuel burned in the boiler. See the response to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 18.

Commenter Name: Elizabeth McMeekin
Commenter Affiliation: PPG Industries, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-3778-A1
Comment Excerpt Number: 11

Comment: EPA has acknowledged boiler design considerations driven by fuel type in a similar source category MACT standard -the MATS Rule (February 16, 2012). In the May 3, 2011 Utility MACT proposed rule (see page 25037}, EPA observed significant differences in mercury emissions between boilers burning high-rank and low-rank coals and concluded that the different mercury emission standards were appropriate for these two different fuel types.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 18.

Commenter Name: Lorraine Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1
Comment Excerpt Number: 21

Comment: For regulation of PM, HCl, and Hg, EPA should place any solid fuel boiler that burns at least 10 percent coal on an annual heat input basis in the —unit designed to burn coal/solid fuel|| subcategory. Since combination boilers are specifically designed to burn a variety of materials (coal, bark, TDF, biomass residuals, etc.) that do have significant and varying chlorine and mercury contents, such classification may be appropriate for these units. This affords them compliance options to either: (1) shift to a cleaner relative mix of feeds (e.g., less coal and more biomass); or (2) install control technology to meet the emission standards. Just as with coal boilers, it would not be fair or appropriate to require these combination units to meet emission standards set by boilers burning at least 90 percent biomass, the top performers of which have very low levels of mercury and chlorine in their feeds and therefore do not have add-on controls for these pollutants. EPA should allow combination units to remain subject to the CO standards for the applicable biomass design subcategory as long as they burn at least 10 percent biomass. CO emissions from combination units are influenced more by the biomass burned than the coal.

Response: For a response to the claim that a solid fuel subcategory is unjust for Hg and HCl, please see comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 18.

Commenter Name: Pat Dennis
Commenter Affiliation: Archer Daniels Midland Company
Document Control Number: EPA-HQ-OAR-2002-0058-3670-A2
Comment Excerpt Number: 5

Comment: EPA should subcategorize coal and biomass and apply Fuel Variance Factors to both subcategories.

Response: For discussion of the request for separate coal and biomass subcategories for Hg and HCl, please see comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 18. Comments pertaining to fuel variability factors are outside the scope of this comment response document.

Commenter Name: Elizabeth McMeekin

Commenter Affiliation: PPG Industries, Inc

Document Control Number: EPA-HQ-OAR-2002-0058-3778-A1

Comment Excerpt Number: 13

Comment: Defining the emissions limits for Hg and HCl based on a combined coal/biomass subcategory results in artificially low Hg and HCl emissions standards for coal-fired boilers. The consistent achievability of these low emissions limits for most coal-fired boilers is very uncertain. Weighing the high cost of installing controls on these coal-fired boilers and the uncertainty of achieving consistent compliance even with the controls, many facilities, such as PPG's, may be forced to shut down their coal-fired boilers.

Response: The EPA disagrees that the emission limits are biased low. Based on reported emissions data, 87 existing coal-fired boilers are already demonstrating compliance with the mercury emission limit in the final rule and 40 existing coal-fired boilers are already demonstrating compliance with the HCl emission limit in the final rule. The EPA therefore believes that all coal-fired sources have the ability to demonstrate compliance with the limits. Comments pertaining to the economic impact of the rule on individual facilities are outside the scope of this comment response document.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 65

Comment: We support retaining the solid fuel subcategory for HCl and Hg. EPA correctly points out that HCl and Hg are fuel-based pollutants and that the top performers in the solid fuel subcategory combust a variety of solid fuel types (biomass, coal, petcoke, and TDF). There are several designs of boilers (e.g., stokers, hybrid suspension grate, suspension/ pulverized coal, and fluidized bed units) that are capable of burning multiple types of solid fuel. EPA has quite a bit of emissions data from these "combination" units. To accommodate the fuel diversity among solid fuel units, it is appropriate to use the data from boilers burning multiple types of solid fuel, and not just data from those burning 90 percent of one kind of solid fuel to develop limits for HCl and Hg for a solid fuel subcategory. The MACT standards must be achievable, and this approach of analyzing data from units burning many types of solid fuels makes the MACT floors for HCl and Hg from a combined solid fuel subcategory achievable for many types of boilers.

Response: The EPA thanks the commenter for their support.

Commenter Name: Holly R. Hart

Commenter Affiliation: United Steel Workers (USW)

Document Control Number: EPA-HQ-OAR-2002-0058-3498-A1

Comment Excerpt Number: 1

Comment: USW supports EPA's proposals as described at pages 80600-01 of the federal register notice to create one single category of solid fuel boiler with respect to the fuel based pollutants.

Response: The EPA thanks the commenter for their support.

Commenter Name: Stephen E. Woock

Commenter Affiliation: Weyerhaeuser Company

Document Control Number: EPA-HQ-OAR-2002-0058-3523-A1

Comment Excerpt Number: 7

Comment: We support EPA's decision to keep the solid fuel subcategory finalized in March 2011 for HCl and Hg. As EPA points out, HCl and Hg are fuel-based pollutants and the top performers in the solid fuel subcategory combust a variety of solid fuel types. In addition, the top performers represent a variety of boiler types and controls.

Response: The EPA thanks the commenter for their support.

Commenter Name: Bart Sponsellar

Commenter Affiliation: Wisconsin Department of Natural Resources

Document Control Number: EPA-HQ-OAR-2002-0058-3527-A2

Comment Excerpt Number: 3

Comment: The MACT rule originally distinguished between coal and biomass fuels in establishing emission limitations for fuel based pollutants such as mercury and chlorine. Under the MACT Reconsideration, EPA is proposing to establish one "solid fuel" category with one limit that encompasses coal and biomass fuels. The only distinction in emission limitations is between new and existing solid fuel sources.

The Department supports a single solid fuel category in setting MACT mercury and Hydrogen Chloride emission limitations for source categories which can burn either coal or biomass. This approach acknowledges that biomass is a cleaner fuel – in many cases cleaner without controls than coal fueled sources with controls. Because biomass with controls is much more stringent than coal meeting MACT, a source may very well switch back to coal and emit more total emissions even though the source is controlled to the MACT emission limitation. Fuel switching to cleaner fuels has long been considered a control option by EPA and the MACT standards should not work against this approach. Establishing the single category also acknowledges that sources may have switched to biomass fuels in response to other pollutant regulations or renewable energy mandates. These sources should not be asked to control pollutants to levels required for coal fired sources. Further, some sources would be punished for voluntarily reducing greenhouse gas emissions or utilizing clean biomass residues instead of fossil fuels.

Response: The EPA thanks the commenter for their support.

Commenter Name: Bart Sponsellar
Commenter Affiliation: Wisconsin Department of Natural Resources
Document Control Number: EPA-HQ-OAR-2002-0058-3527-A2
Comment Excerpt Number: 4

Comment: Although we support a single solid fuel category, it appears that this category should only apply for subcategories of boilers capable of burning both coal and biomass. The Department sees a distinction where boilers or processes designed to burn only biomass should remain in a biomass category. Clearly, several subcategories such as pile burners, dutch ovens, suspension burners, fuel cells, and kiln-dried wood boilers are designed or are dedicated to burn only biomass. Most sources in other boiler types that typically burn coal or even a mixture of coal and biomass are not even capable of burning 100% biomass. Therefore, the fuel based emission profiles of these dedicated biomass source subcategories are not applicable to other boiler subcategories. The Department believes that certain source categories, which are dedicated or designed as a whole for primarily burning biomass, should remain as a separate biomass fuel category. This suggested biomass category appears to include pile burners, dutch ovens, suspension burners, and fuel cells.

Response: The MACT floor emission limitations for Hg and HCl for solid fuel boilers were calculated from the emissions from both coal and biomass combustion. In addition, the threshold criterion for considering performance tests from co-fired units was 90 percent of a fuel type. For this reason, the EPA believes that all sources will be able to demonstrate compliance with the emission limitations regardless of the fuel they are combusting. The EPA believes this mitigates any concerns over units not being designed to combust one type of solid fuel versus another.

Commenter Name: Bart Sponsellar
Commenter Affiliation: Wisconsin Department of Natural Resources
Document Control Number: EPA-HQ-OAR-2002-0058-3527-A2
Comment Excerpt Number: 5

Comment: Biomass fuel is not equally available to all sources or even in the same form or quality. Many sources burning biomass have a dedicated or specific source of biomass material such as bagasse or a by-product from a facility process such as dry kiln wood or waste bark. Even where boilers are burning logging residues the fueling is inherent to the surrounding resources. It is well known that placing sizable units which are 100% biomass fired requires a fuel aggregation system over a very large area. For these reasons, EPA cannot reasonably assume that the emission characteristics found for individual boilers firing biomass can be applied to other units in the same source sub-category. Rather, the fueling of biomass in these categories should be viewed as a site specific alternative and is simply a cleaner burning fuel used in controlling emissions compared to coal. In contrast sources firing coal have the ability to alter and obtain fuels on the open market with consistent and desired characteristics. The Department believes that certain source categories, which are dedicated or designed as a whole for primarily burning biomass, should remain as a separate biomass fuel category. This suggested biomass category appears to include pile burners, dutch ovens, suspension burners, and fuel cells.

Response: The EPA acknowledges that not all solid fuel units are designed to combust biomass, and that not all biomass fuels are widely available to all sources. The MACT floor emission limitations for Hg and HCl for solid fuel boilers were calculated from the emissions from both coal and biomass combustion. The units combusting biomass were located in several different parts of the U.S., and the variability of these fuels was factored into the 99% UPL. For this reason, the EPA believes that all sources will be able to demonstrate compliance with the Hg and HCl emission limitations regardless of the fuel they are combusting. The EPA believes this mitigates any concerns over the availability of biomass fuels.

Commenter Name: Bart Sponsellar

Commenter Affiliation: Wisconsin Department of Natural Resources

Document Control Number: EPA-HQ-OAR-2002-0058-3527-A2

Comment Excerpt Number: 6

Comment: The Department believes it is appropriate to include pulverized coal, stoker, and fluidized bed boilers in an overall solid fuel fired category in establishing mercury and hydrogen chloride emission limitations. However, the setting of these emission limitations should be based on sources firing 90% or more of coal at the time of testing. At a minimum the emission limitations should not be based on sources firing biomass in sizable quantities. Biomass is a fuel which is not readily available to all sources. This approach to a solid fuel category will alter a significant number of sources currently counting toward the solid fuel MACT floor. The Department reviewed the sources included in the MACT floor and cross-referenced those sources identified as burning biomass fuels by EPA. This analysis, shown in Appendix A, [See submittal, page 9, for Appendix A] shows that for mercury, 13 of 19 sources in the floor (33%) are dedicated or primarily biomass fired. The biomass sources are highlighted in the table. In the hydrogen chloride floor, 16 of 45 sources (36%) appear to be dedicated or primarily biomass fired. The emission limitations for solid fuel, should at a minimum, eliminate sources burning primarily biomass in determining the MACT floor. The Department also suggests EPA evaluate this same suggested solid fuel and biomass hybrid approach for nonmercury metals which are also fuel-based.

Response: The EPA intends for source to demonstrate compliance with emission limitations at all times (excluding periods of startup, shutdown, or when the unit is not operating), regardless of the fuel mixture. Given that the best-performing Hg and HCl emitters comprise a mixture of tests combusting biomass and coal, the EPA believes that any mixtures of the two fuels should yield similar emissions profiles. For this reason, the EPA has elected to retain the criterion for the Hg and HCl MACT floor calculations that tests must be burning at least 90% solid fuel, and not just 90% coal or 90% biomass. In addition, as the commenter points out, a high percentage of the best performers used to established the Hg and HCl emission limits are dedicated biomass units,

For the reasons specified in the preamble to the December 23, 2011 proposed rule notice (76 FR 80598), the alternative emission limitations for total metals remain on a combustor design basis.

Commenter Name: Bart Sponsellar

Commenter Affiliation: Wisconsin Department of Natural Resources

Document Control Number: EPA-HQ-OAR-2002-0058-3527-A2

Comment Excerpt Number: 7

Comment: An alternative needs to be considered for the suggested biomass dedicated source category. Since these sources burn fuels which are not widely available to all sources and which in many cases are site specific. Therefore EPA should not apply the emissions profile across this source category. This is particularly true for many sources where the chloride and mercury content is a result of environmental conditions or deposition of the contaminant. The Department suggests EPA consider whether an emission limitation can be accurately established in this case or if these pollutants should be subject to a work practice requirement.

Response: The EPA acknowledges that not all solid fuel units are designed to combust biomass, and that not all biomass fuels are widely available to all sources. The MACT floor emission limitations for Hg and HCl for solid fuel boilers were calculated from the emissions from both dedicated coal and biomass combustion. For this reason, the EPA believes that all sources will be able to demonstrate compliance with the emission limitations regardless of the fuel they are combusting. The EPA believes this mitigates any concerns over the availability of biomass fuels.

Commenter Name: Dell Majure

Commenter Affiliation: Kimberly-Clark Corp.

Document Control Number: EPA-HQ-OAR-2002-0058-3692-A2

Comment Excerpt Number: 1

Comment: FB boilers are designed to combust fuel with relatively low heating value and high ash compared to other combustor designs. There are two subcategories for FB boilers, one is for coal and the other is for biomass that have emission limits of 56 ppmv @ 3 % O₂ and 370 ppmv @3 % O₂, respectively. The large difference in the emission limits reflects the differences in the fuel properties of coal and biomass.

The fuel properties of coal have a wide range of heating values and ash content. The design of coal-fired FB boilers depends on the fuel properties. The design has to be altered to sustain combustion as the heating value decreases and to ensure the heat in the ash is utilized in order to be economically viable to operate the boiler as the ash content increases.

FB boilers are designed to have large tube surface areas to transfer heat from the fuel through the process of conduction and convection. Conductive heat transfer takes place with ash to tube surface contact in the furnace section through the cyclone flue gas circuit. Convective heat transfer with flue gas occurs after the cyclone outlet in the back pass of the boiler.

As the heating value decreases and ash content increases the amount of tube surface area in the furnace required for conductive heat transfer is exceeded. A separate tube surface area is required outside of the furnace section to achieve the desired steaming rate and required conductive heat transfer.

In order to achieve this design requirement, certain FB boilers adopt a FBHE design to achieve rapid heat transfer. This ability can be simply explained by the FBHE design where the entire tube surface is exposed to the flue gas stream containing ash, as compared to approximately a

third to half of the furnace tube surface area in a conventional FB design. The FBHE is located at the exit of the cyclone section of the unit and facilitates a means of providing heat to the evaporative water and superheated steam circuits of the boiler.

In addition, the FBHE is designed with the injection of fresh air into the flue gas to improve mixing and combustion of the remaining fuel in the flue gas that is recirculated to the furnace section. This allows the boiler to combust coal with a lower heating value than a coal-fired FB without a FBHE.

Figure 1 and 2 shows a diagram of a FB boiler without a FBHE and one with a FBHE [see submittal for Figures 1 and 2].

Response: We agree with the commenter that Fluidized Bed units with an integrated heat exchanger warrant further subcategorization. Under CAA section 112(d)(1), the Administrator has the discretion to distinguish among classes, types, and sizes of sources within a category or subcategory in establishing standards. The EPA maintains that, normally, any basis for subcategorization (*i.e.*, class, type, or size) must be related to an effect on HAP emissions that is due to the difference in class, type, or size of the units. Because this design allows the boiler to combust coal with a lower heating value than a coal-fired fluidized bed boiler without a fluidized bed heat exchanger, this boiler design does have different combustion-related HAP emission characteristics. Thus, a new subcategory of coal fluidized bed with integrated heat exchanger was added to the final rule. This is similar and consistent to the subcategory added in MATS for boilers designed to burn low rank coal.

The final rule includes emission limitations for this subcategory.

Commenter Name: C. Richard Neff

Commenter Affiliation: Cogentrix Energy, LLC

Document Control Number: EPA-HQ-OAR-2002-0058-3627-A2

Comment Excerpt Number: 1

Comment: Cogentrix operates two facilities, one with coal-fired cogeneration units and the other with coal-fired electric generation units, each of which has generator capacity of more than 25 megawatt electrical (MWe) and combustion units of less than 250 MMBtu/hr. Both Cogentrix sites are designed with two "three-on-one" boiler-to-generator configurations, in which three boilers provide steam to one 55-MWe electric generator. All boilers have opted-in to the Acid Rain Program (ARP) and are equipped with dry scrubbers and bag houses.

The three-on-one boiler-to-generator configuration results in an unusual, and perhaps unique, issue regarding applicability of NESHAPs, the ARP, and the Cross-State Air Pollution Rule (CSAPR). Specifically, despite having already opted-in to the ARP and installed scrubbers and baghouses, the boilers at both Cogentrix sites now face being whipsawed between the proposed NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters ("Boiler MACT") and the CSAPR, which is intended to be applicable only to electric generating units (EGUs).

I. Regulatory Inequality and Disparate Impact Demand a Further Boiler MACT Subcategory.

Cogentrix has noted in its previous comments to EPA on the proposed Utility MACT, and CSAPR rules that these two facilities have historically been treated as EGUs by the permitting authorities. Indeed, EPA originally included these two facilities in the Utility MACT ICR, not in the Boiler MACT ICR. Although the proposed "Boiler MACT" in 40 CFR 63.7491(a) appeared to exclude electric utility steam generating units from applicability of this rule, the proposed Utility MACT was ambiguous. It appeared to exclude units such as Cogentrix's, thus leaving them orphaned and subject to the Boiler MACT. Cogentrix commented to seek clarification that its units would be covered by the Utility MACT. To its surprise, in the December 2011 Responses to Comments on Utility MACT, EPA determined, "[T]he combustion units at the two [Cogentrix] facilities are subject to the Industrial Boiler NESHAP rather than the EGU NESHAP because they do not meet the size requirement of the CAA section 112(a)(8) definition of an EGU."

The crux of the comments in this letter address the regulatory inequality and competitive distortion that EPA has created by, on the one hand, treating the two facilities as EGUs by subjecting them to CSAPR, while on the other hand, not treating the two plants as EGUs (i.e., imposing Boiler MACT rather than Utility MACT).

The applicability of NESHAP rules, CSAPR, and ARP are focused on different industry source groups. That the two Cogentrix facilities are being whipsawed between rules that were created for different industry source groups creates both competitive distortions against these plants and difficult compliance challenges for Cogentrix. The proposed Boiler MACT establishes emissions limitations for both hydrochloric acid (HCl) and carbon monoxide (CO), while the analogous NESHAP for EGUs, the "Utility MACT," does not require reductions (or monitoring) of either CO or HCl. The CSAPR requires TR NO_x Annual Units either to emit less than their annual and ozone-season allocations of NO_x for both operating periods or to purchase additional allocations. Since emissions of CO and NO_x are inversely related, Cogentrix faces greater challenges to control emissions than do its electric utility competitors for power sales: both Cogentrix and its competitors must reduce NO_x emissions under CSAPR, but only Cogentrix must do so while simultaneously reducing CO and HCl. There is no public policy rationale to support this disparate treatment.

The most suitable way for EPA to avoid such unwarranted disparate impact of its NESHAP rules is to craft appropriate subcategories of sources and to tailor the requirements for each. Section 112(c)(1) directs EPA to make the industrial categories and subcategories for NESHAP's rules "consistent with the list of source categories established pursuant to" section 111 (New Source Performance Standards), "to the extent practicable." Section 112(b)(2) in turn authorizes the Administrator to "distinguish among classes, types and sizes within categories of new sources." For purposes of the NESHAPs, section 112(c)(1) preserves "the Administrator's authority to establish subcategories under this section, as appropriate." The need for a subcategory here is more than "appropriate," it is compelling.

Cogentrix urges EPA to cure this unequal impact of its NESHAP rules by creating a subcategory in Boiler MACT for facilities that are subject to CSAPR and have opted-in to the ARP and installed scrubbers and baghouses. Under this sub-category, a Boiler MACT facility could comply with NESHAP requirements for acid gases and dioxin/furans using compliance methods defined under Utility MACT. A facility that looks and operates like an EGU while being subject to this sub-category under Boiler MACT would have the capability to comply with its applicable

NESHAP, CSAPR, and ARP without the competitive disadvantage it will experience absent such a sub-category.

With respect to HCl, for example, EPA recognized in the Utility MACT the effectiveness of scrubbers. HCl is a strong acid with a large acid dissociation constant. As such, HCl readily separates in acid-base reactions with caustic sorbents. EPA cites both HCl and hydrofluoric acid (HF) as being effectively removed using flue gas desulfurization (FGD) control technologies (e.g., dry sorbent injection) upstream from a PM control device.³ While both acid gases and SO₂ are absorbed when using this control technology, EPA states that acid gases are removed even more rapidly and readily than SO₂. Having opted-in to the ARP, Cogentrix operates FGD technology and an SO₂ CEMS to comply with the provisions of the ARP. Cogentrix's ARP subcategory proposal is thus consistent with the Utility MACT while achieving the HCl reduction goals of Boiler MACT. EPA already considers SO₂ a commonly measured pollutant and allows SO₂ to be monitored as a surrogate for acid gases. Allowing this compliance method for a narrow sub-category of FGD-equipped units under Boiler MACT would achieve EPA's HAP reduction goal, while treating similar sources equally and avoiding competitive distortions.

With respect to the use of CO as a surrogate for non-dioxin/furan HAPs, EPA's Utility MACT ICR showed that non-dioxin/furan organic HAP emissions from EGUs are low and often below EPA test method detection levels. EPA determined that inaccuracy in measurements along with the extended sampling times from the ICRs fulfills the criteria in CAA Section 112(h) for implementation of work practice standards for organic HAP, rather than using CO, VOC, or THC as surrogates.⁴ The Cogentrix boilers operate with organic HAP emission rates comparable to other utility boilers that are treated as EGUs under section 112. In fact, the Cogentrix boilers were included in the Utility MACT ICR. There is no reason to believe that the composition of non-dioxin/furan organic HAP would be dissimilar from those other EGUs tested in the Utility MACT ICR.

Likewise, EPA concluded in the proposed Boiler MACT that work practice standards are appropriate for dioxin/furan emissions based on boiler data similar to that collected from EGUs. Therefore, Cogentrix requests that work practice standards (per Utility MACT), rather than a surrogate CO emission standard, be established for non-dioxin/furan organic HAP emissions from units within the Boiler MACT subcategory that are subject to the CSAPR and have opted-in to the ARP and installed FGD controls. This compliance option would eliminate the serious competitive disadvantage for units that would otherwise be subject simultaneously to CO limitations under Boiler MACT and to NO_x caps under CSAPR.

[Footnote 2: Please see: http://www.epa.gov/ttn/atw/utility/mats_rtc_chapters_foreword-1-2-3-4-121611.pdf; regarding Commenter 17845 (page 294).][Footnote 3: Federal Register *I* Vol. 76, No. 85 *I* May 3, 2011 Proposed Rules.]

[Footnote 4: Federal Register *I* Vol. 76, No. 85 *I* May 3, 2011 Proposed Rules.]

Response: The EPA disagrees with establishing subcategories based on the end use (i.e., electricity production) of a boiler or process heater. The EPA maintains that, normally, any basis for subcategorization (i.e., class, type, or size) must be related to an effect on HAP emissions that is due to the difference in class, type, or size of the units. The EPA has instead established subcategories based on the boiler design which is based on the fuel type combusted. The EPA does not believe the

Cogentrix units exhibit vastly differing emissions profiles than other similarly-designed boilers or process heaters in the industrial, commercial, and institutional source category solely because they produce electricity. There are many other boilers included within the source category that are producing electricity.

7C01. New Biomass Subcategories (General Comments)

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 70

Comment: EPA has decided to designate any major source that burns at least 10% biomass as a biomass burner (pages 80601 and 80655 of the major source rule). This means that a facility burning 90% coal and 10% biomass would be held to the less rigorous PM emission standard for biomass than for coal. This is arbitrary. At a minimum, the rule should make basic sense. This does not pass that test. [See Submittal for table comparing coal and biomass limits.]

Response: Several comments were received on initial June 4, 2010 proposal with respect to how combination fuel units should be classified. The EPA presented its rationale in its response to comments on the appropriate fuel use threshold of combination boilers (see 76 FR 15635). EPA did not propose to revise this rationale in this reconsideration action and maintained a consistent cutoff of 10% biomass to determine the appropriate subcategory assignment in this final amendments. The EPA was not petitioned for reconsideration on this topic and it did not re-open the fuel threshold level for subcategory determination in this final notice therefore this comment is outside the scope of this reconsideration action.

Commenter Name: Michael Livermore, Jason Schwartz

Commenter Affiliation: Institute for Policy Integrity, NYU School of Law

Document Control Number: EPA-HQ-OAR-2002-0058-3432-A1

Comment Excerpt Number: 2

Comment: EPA should explore the justifications for subcategorization for new sources separately. Compared to existing sources, new sources do not face the same limitations on their design options. EPA must explain why for new, still-unconstructed sources, it would not be more efficient to set a single standard and let all new sources choose any fuel type and design option capable of meeting that standard.

Response: The EPA disagrees that a single standard for all new sources is justified. Emissions of CO, PM, and metallic HAP vary greatly with the design of the combustion unit; the same lot of fuel could exhibit a vastly different emission profile between different combustor designs. Additionally, sources may be limited in their subcategorization choices due to the geographic availability of some fuels and their energy requirements. These conditions may limit or dictate what design type of coal or biomass boilers can be installed. The design types currently being used were installed for specific reasons which may be just as applicable for future installations. For these reasons, the EPA believes that separate emission limitations are justified for all of the combustor-based subcategories.

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 4

Comment: EPA's subcategories for new units are, if possible, even more unlawful and irrational. Nowhere does the agency explain why it wishes to encourage the construction of obsolete boilers that, according to the agency at least, emit far more pollution than other boilers. It is entirely possible for a company that wishes to build a new boiler to build one that is clean. Assuming *arguendo* that the boiler designs on which EPA has seized as an excuse for setting different standards for existing boilers truly do affect emissions in a meaningful way, then they are also necessarily a means by which pollution can be controlled. Accordingly, EPA should set new source standards based on sources that have the lowest emissions as a result of their cleaner design as well as of the other factors that affect their emission levels.

Response: The commenter disagrees with the EPA's subcategories for new sources, but does not provide any explanation or analysis to support its assertion that the subcategories are "unlawful and irrational." As noted elsewhere in the record for today's action, section 112 provides EPA with broad discretion to subcategorize among sources in a source category. Under the commenter's approach, EPA would likely never be able to exercise this authority, since some types of sources will generally always be lower-emitting than others. Given that Congress used such broad language when authorizing EPA to create subcategories, it is unlikely that such a result is what it intended. Moreover, as explained elsewhere in the record for today's action, the EPA has established emissions standards for new sources based on the best-performing similar source, as required by section 112(d). Therefore, the EPA's standards are in fact based on sources with the lowest emissions levels, consistent with the requirements of the Act.

As indicated in the response to comment EPA-HQ-OAR-2002-0058-3432-A1, excerpt 2, the type of boilers selected for installation in the future is based on several factors including fuel availability and the facilities' energy demands. For example, a facility planning on a new coal boiler may select a pulverized coal unit because it requires a high steam production which a stoker would not provide, or it may select a fluidized bed coal unit if the fuel is of low quality. The same is true for biomass, certain types of biomass can only be combusted in a certain type of boiler designed to combust that type of biomass. In either case, the final rule has a single emission limitation for mercury and HCl for all solid fuel subcategories, and a single PM emission limitation for the 3 coal subcategories. In addition, any new boiler (above 30 MMBtu/hr) will be subject to an NSPS (subpart Db for units greater than 100 MMBtu/hr, subpart Dc for boiler 30 to 100 MMBtu/hr.) which regulate PM, SO₂ and NO_x emissions which will also factor into what boiler type a facility will elect to install for future energy needs.

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 71

Comment: Sub-classifications do not correspond to the population of burners now being permitted EPA has designated still more sub-classifications of biomass boiler type than it had before. Our permit database indicates that new boilers now being permitted around the country do not fall under the categories of biomass boiler that EPA designates. Almost all are either stokers or fluidized bed boilers. We have never seen a permit for a new "dutch oven" or "biomass fuel cell". EPA's ever-growing number of categories corresponds to a shrinking population of burners in each category, rendering the MACT floors meaningless. The floors set in subclassifications do not reflect generally achievable rates, as illustrated above.

Response: The EPA acknowledges that the majority of new units designed to combust biomass fuels are projected to be stokers or fluidized bed units. The EPA disagrees that subcategorization outside of stokers and fluidized bed units is unjustified. Regardless of new unit construction, there are many Dutch Ovens (22) and fuel cells (29) combusting biomass fuels that are currently in operation in the United States with the latest one (FC) being installed in 2006. In any energy application, the boiler is designed to make the best use of temperature, turbulence, and time (the three "T" of combustion). All three of these aspects relate directly to the properties of the fuel to be used (moisture content, particle size, ash content, and heat value). For example, Dutch ovens find application where the anticipated wood fuel has a high (up to 60 percent) moisture content. Further, the EPA continues to believe that the subcategories for new and existing units should be identical because of the fact that a reconstructed existing unit will be subject to the same emission limitations as a newly constructed boiler. If the Dutch Oven and Fuel Cell subcategories are eliminated for new sources, they would also be removed for existing sources; this would potentially place units currently in operation into subcategories for which their combustion characteristics and emissions profiles are vastly different.

Commenter Name: Mark Weiss

Commenter Affiliation: Reciprocal Energy Company

Document Control Number: EPA-HQ-OAR-2002-0058-3658-A2

Comment Excerpt Number: 9

Comment: The EPA should consider further separation of Suspension Combustion sub-categories:

Biomass Suspension Combustion:

1. With unsupported flames.
2. Load following thermal applications with more than 40% of run time at less than 75% capacity
3. With powdered fuel that is site milled. This would separate "dust burning" technology from technology designed to run with high efficiency, standard boilers without significant bottom ash. This is a significant issue, as hammer-mill technology cannot economically produce powder that is fine enough to reduce CO levels at or near the proposed 58 PPM.

New data should be collected within these categories. The 3-hour test should be modified to more correctly measure the operation of the boiler at 50% or 60% fire rates. A properly tuned suspension combustion system can combust more than +99.5% of the fuel and boiler efficiency

can exceed 84%. Load following applications reduce fuel consumption and overall plant emissions but can result in higher, short term CO levels.

Response: The EPA disagrees that further subcategorization is necessary for Suspension Burners. The EPA acknowledges that units which combust biomass fuel in suspension have different combustion characteristics and emissions profiles than other combustor designs (e.g., Stokers). The EPA does have data to determine if the differences in combustion styles result in different emission profiles between the three specified subcategories of suspension burners to warrant further subcategorization. The commenter also did not provide data to support the comment.

Commenter Name: M.L. Steele

Commenter Affiliation: CraftMaster Manufacturing, Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3814-A1

Comment Excerpt Number: 3

Comment: Biomass Subcategory assignment method. We have learned from previous comments and responses (see Document Control Number EPA-OAR-0058-1907.1, Comment Excerpt #3) that USEPA had assigned the biomass-fired boiler and process heater units to their respective combustor design subcategories using the procedure outlined in USEPA's memo "Revised Development of Baseline Emissions Factors for Boilers and Process Heaters at Commercial, Industrial, and Institutional Facilities", January, 2011. *For units employing more than one biomass combustor design*, the procedure established a hierarchy to assign the unit to a single subcategory. The hierarchy was, 1) Fluidized Bed, 2) Stokers, 3) Dutch Oven/ Suspension Burners, 4) Suspension/ Grate, and 5) Fuel Cells. Then, under the hierarchy approach, if a biomass boiler could have been fired using a combination of "Air-Swept Stokers" and "Suspension Burners", the boiler was assigned to the "Stoker" subcategory.

If the hierarchy is still in use (albeit modified to accommodate the changes to the biomass subcategories found in the current proposed rules), we must confirm CraftMaster's earlier objection because we believe the hierarchy approach is arbitrary and an inappropriate method of assigning units to a subcategory. This concern applies to units that make up the MACT Floors and for classification of units for ongoing compliance purposes. The assignment should be based on a meaningful parameter, the heat input from each combustor design. For the MACT Floor units, the subcategory assignment should be based on the fuel *and combustor design* that provided 90% or more of boiler heat input during the stack test. For compliance purposes, the applicable subcategory (and limits) should be determined based on the combustor design that provided the majority of the heat input over the last twelve consecutive month period.

Response: The EPA is maintaining the approach as described in the memorandum "Revised Development of Baseline Emissions Factors for Boilers and Process Heaters at Commercial, Industrial, and Institutional Facilities", November 2011. The Clean Air Act does not require that the EPA establish subcategories within a source category, but rather provides discretion to do so based on class, type, or size. The EPA believes the approach described in the memorandum referenced above represents a reasonable subcategory assignment given the data available to the EPA at the time of this rulemaking. The ICR survey data did not contain information on heat input provided to each specific type of combustor, and thus there was no way to distribute the

database according to the methods described by the commenter. The EPA has worked to correct the subcategory assignments of several units in the inventory based on public comments and when specific examples of multiple combustor units were provided to the EPA to indicate that the majority heat input was provided by a certain type of combustor, the unit's classification was changed to reflect the combustor design most representative of the unit.

Commenter Name: M.L. Steele

Commenter Affiliation: CraftMaster Manufacturing, Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3814-A1

Comment Excerpt Number: 4

Comment: We acknowledge that in the current proposed rules USEPA has considered for those units in the CO and PM MACT Floors that they must be $\geq 90\%$ biomass-fired during the stack testing to be considered in the Floor. However this should be taken one step further to $\geq 90\%$ biomass-fired *and fired by the combustor design for the applicable subcategory*. To do otherwise could introduce data that is not representative of the subcategory due to a co-firing situation similar to that noted in the PM MACT Floor study for biomass suspension-fired units where units co-fired with natural gas were removed from the MACT Floor.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3814-A1, excerpt 3.

Commenter Name: M.L. Steele

Commenter Affiliation: CraftMaster Manufacturing, Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3814-A1

Comment Excerpt Number: 5

Comment: With respect to guidance in classifying a unit employing more than one biomass combustor design for compliance purposes, the proposed regulations are silent.

It is not known how many sources are not properly classified in the MACT Floors as a result of the hierarchy, however, many boilers do utilize multiple combustor designs. For compliance purposes it is essential that each biomass unit be assigned to its proper combustor-design subcategory and not arbitrarily assigned to the "Stoker/ sloped grate/ other firing wet biomass" subcategory.

Response: For compliance purposes, it is the source that submit the Initial Notification of Applicability in which the source would identify the affected units and their subcategory. The regulatory agency would only assigned the subcategory if the source requested an Applicability Determination. The regulatory agency would make the determination based on data and information supplied by the source.

Commenter Name: Randall D. Quintrell

Commenter Affiliation: Georgia Paper & Forest Products Association

Document Control Number: EPA-HQ-OAR-2002-0058-3451-A1

Comment Excerpt Number: 18

Comment: We support the separate CO subcategories for biomass boilers, recognizing the significant design differences based on boiler type and fuel type.

Response: The EPA thanks the commenter for their support.

Commenter Name: Holly R. Hart

Commenter Affiliation: United Steel Workers (USW)

Document Control Number: EPA-HQ-OAR-2002-0058-3498-A1

Comment Excerpt Number: 2

Comment: USW supports EPA's proposal to define with respect to the combustion-based pollutants any boiler that burns 10% or more biomass as a biomass boiler. The unique emissions characteristics of biomass boilers are such that if this had not been done, the regulation would have rendered most mixed-fuel boilers non-viable and worked to discourage operators that might have considered mixing renewable biomass with fossil fuel.

Response: The EPA thanks the commenter for their support.

Commenter Name: Holly R. Hart

Commenter Affiliation: United Steel Workers (USW)

Document Control Number: EPA-HQ-OAR-2002-0058-3498-A1

Comment Excerpt Number: 3

Comment: USW supports EPA's decision as described at pages 80607-8 to create additional biomass and solid fuel subcategories to adequately reflect the many different types of such equipment used by industry and the different emissions characteristics of this variety of equipment. Doing so will allow for realistic emissions limits for operators of such boilers.

Response: The EPA thanks the commenter for their support.

Commenter Name: Michael L. Krancer

Commenter Affiliation: Pennsylvania Department of Environmental Protection (DEP)

Document Control Number: EPA-HQ-OAR-2002-0058-3507-A1

Comment Excerpt Number: 6

Comment: In the final rule, the EPA added subcategories for hybrid suspension/grate biomass units, limited use units, solid fuel units, and non-continental liquid units. The EPA also added a fuel specification to the final rule that would allow units combusting gases not defined as "Gas 1" gases to qualify as Gas 1 units by demonstrating that the fuels combusted meet a fuel specification. In the reconsidered rule, the EPA added additional subcategories for units designed to burn heavy liquids, units designed to burn light liquids, biomass dry stokers, biomass hybrid suspension/grate boilers and biomass pile burners/dutch ovens.

The DEP believes that it is appropriate to add new subcategories due to the unique design of these units. Therefore, the DEP agrees with the EPA's proposal to add new subcategories.

Response: The EPA thanks the commenter for their support.

Commenter Name: Heather Parent

Commenter Affiliation: Maine Department of Environmental Protection

Document Control Number: EPA-HQ-OAR-2002-0058-3691-A2

Comment Excerpt Number: 3

Comment: Maine DEP supports the addition of subcategories for biomass units based on the type of unit and the type of biomass combusted.

Response: The EPA thanks the commenter for their support.

7C02. Biomass: Kiln-Dry Stoker/Sloped Grate/Other

Commenter Name: Bill Lane

Commenter Affiliation: American Home Furnishings Alliance (AHFA)

Document Control Number: EPA-HQ-OAR-2002-0058-3676-A2

Comment Excerpt Number: 5

Comment: We noted that the Preamble to the Proposed Reconsideration Rule has a typo. In its discussion of fuel in the dry biomass subcategory at Section V.C.5.b (76 Fed. Reg. at 80608), EPA refers to biomass fuel with a moisture content of "less than 2 percent." This should be corrected to "20 percent."

Response: The EPA thanks the commenter for identifying this typographical error. Discussion of biomass moisture content was correct in the proposed rule language and a description of the final subcategories in the final preamble will reflect the appropriate moisture content.

Commenter Name: Philip Lewis

Commenter Affiliation: Michigan Biomass - Grayling Generating Station

Document Control Number: EPA-HQ-OAR-2002-0058-3815-A1

Comment Excerpt Number: 2

Comment: A separate category for biomass distinguishes between boilers that use dry wood vs. wet wood. The carbon monoxide (CO) emissions in particular are so divergent for the fuels that driving biomass boilers to CO levels achieved with dry wood was not achievable without threatening the viability of our operations.

Response: The EPA has revised its CO MACT floor emission limitations for all subcategories since the December, 2011 proposed reconsideration of the rule. Based on new data received, corrections to old data, and inventory changes and using the same MACT floor methodology, the revised CO limit for Stokers/Sloped Grate/Other units combusting kiln-dried biomass fuel in the final rule is 460 ppm corrected to 3 percent oxygen.

Commenter Name: Gary Melow, Director

Commenter Affiliation: Michigan Biomass (MB)

Document Control Number: EPA-HQ-OAR-2002-0058-3478-A1

Comment Excerpt Number: 2

Comment: We strongly support a separate category for biomass distinguishes between boilers that use dry wood vs. wet wood. The carbon monoxide (CO) emissions in particular are so divergent for the fuels that driving biomass boilers to CO levels achieved with dry wood was not achievable without threatening the viability of our operations.

Response: The EPA thanks the commenter for their support.

Commenter Name: Bart Sponsellar

Commenter Affiliation: Wisconsin Department of Natural Resources

Document Control Number: EPA-HQ-OAR-2002-0058-3527-A2

Comment Excerpt Number: 9

Comment: The EPA is proposing carbon monoxide (CO) and particulate (PM) emission limitations for kiln-dried wood boilers (biomass dry stokers) and hybrid suspension grate boilers. This approach by default adjusts the emission limitations for biomass subcategories which previously included these boilers. The Department supports EPA's proposal to more specifically apply emission limitations for CO and PM to each biomass boiler type. However, the Department does have a preferred approach as discussed below. The Department supports EPA's approach because the emission levels of these pollutants are specific to the subcategory sources: CO based on combustion configuration for each boiler type and metals (PM surrogate) based on metal content of the site specific biomass along with the particulate control device. In this latter case, the metals content of kiln-dried biomass is likely very low compared to biomass exposed to the environment. In considering this further, metals content between biomass types will also vary with the length of time it is exposed to the environment. For example, metals accumulating through deposition will be found in increased amounts on tree bark versus on crops harvested annually such as sugar cane. Similar, trends are likely seen for metals taken up from soils – the older biomass may have increased concentrations.

Response: The EPA thanks the commenter for their support.

Commenter Name: Stuart A. Clark

Commenter Affiliation: State of Washington Department of Ecology

Document Control Number: EPA-HQ-OAR-2002-0058-3665-A2

Comment Excerpt Number: 1

Comment: We are pleased that EPA segregated biomass boilers by design type under the Major Source Boiler MACT Rule. This segregation better reflects the capabilities of the various boiler designs. The clear separation of biomass from coal units has provided particulate emission limits that better reflect the capabilities of units burning coal and biomass.

Response: The EPA thanks the commenter for their support.

Commenter Name: Bill Lane

Commenter Affiliation: American Home Furnishings Alliance (AHFA)

Document Control Number: EPA-HQ-OAR-2002-0058-3676-A2

Comment Excerpt Number: 1

Comment: AHFA strongly supports EPA's proposal to establish a new subcategory for units designed to burn kiln-dried biomass. For nearly a century, the wood furniture manufacturing industry has used kiln-dried wood containing less than 20% moisture to generate heat and steam. By combusting kiln-dried biomass in steam-generating boilers, the wood furniture industry avoids the need to rely upon fossil fuels (coal, oil, or gas) for process and domestic heating purposes. By minimizing fossil fuel consumption, our industry has been avoiding a potentially significant source of greenhouse gas emissions for over a century. Our use of this biomass energy resource is consistent with sustainable business practices and EPA goals for reducing emissions of greenhouse gases. Combustion of clean "off-fall" from the furniture manufacturing process for energy recovery purposes also avoids the disposal of this valuable material in landfills.

Due to the unique characteristics of kiln-dried wood, our industry boilers have been sized differently and designed differently to maximize efficiency for the combustion of dry biomass. In addition, our fuel feed systems are uniquely developed for dry storage and handling of wood off-fall. It is clearly appropriate for EPA to designate a new subcategory for this discrete group of boilers.

Response: The EPA thanks the commenter for their support.

Commenter Name: Michael Cassidy

Commenter Affiliation: Kohler Co.

Document Control Number: EPA-HQ-OAR-2002-0058-3803-A1

Comment Excerpt Number: 2

Comment: Kohler Co. agrees with and supports EPA's proposed expansion of boiler/process heater subcategories, especially the inclusion of the kiln dried biomass subcategory.

Response: The EPA thanks the commenter for their support.

Commenter Name: Arthur N. Marin

Commenter Affiliation: Northeast States for Coordinated Air Use Management (NESCAUM)

Document Control Number: EPA-HQ-OAR-2002-0058-3506-A1

Comment Excerpt Number: 14

Comment: Another example of inappropriate parsing of emissions data is the creation of wet and dry biomass fuel subcategories. In principle, NESCAUM does support having separate categories for wet and dry biomass fuel, because different moisture content in biomass fuel changes the CO emission profile of the fuel considerably. With proper emission control technologies installed, both wet and dry stokers units should be able to achieve large PM emission reductions. By creating subcategories for industries in which sources use kiln dried biomass fuel and have not installed adequate controls, the EPA is missing an opportunity to better control these sources.

Response: The EPA disagrees with the commenter's assertion that subcategorization into wet and dry biomass is unnecessary. Under CAA section 112(d)(1), the Administrator has the discretion to distinguish among classes, types, and sizes of sources within a category or subcategory in establishing standards. The EPA maintains that, normally, any basis for subcategorization (*i.e.*, class, type, or size) must be related to an effect on HAP emissions that is due to the difference in class, type, or size of the units. The commenter itself states that there are differences between wet and dry biomass. Facilities which combust kiln-dried biomass (*i.e.*, lumber) fuel are carefully integrated to utilize their available resources, and the combustion units are sized to efficiently combust biomass that has undergone a drying process. This drying process enhances the combustion quality of the fuel. The facilities monitor and maintain specific moisture levels in the fuel, typically to less than 2 percent. The differences between virgin biomass (timber/Green wood) and kiln-dried biomass warrant differing combustion styles and parameters for each fuel type, for which EPA believes subcategorization is justified.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 62

Comment: Biomass Dry Stoker/Sloped Grate/Other. Stoker/sloped grate/other unit designed to burn dry biomass means the unit is in the units designed to burn biomass/bio-based solid subcategory that is either a stoker, sloped grate, or other combustor design and is not in the stoker/sloped grate/other units designed to burn wet biomass subcategory. The dry biomass stoker/sloped grate/other unit subcategory should not be limited to kiln-dried biomass, as there are other types of dry biomass, such as wood dried at plywood and other composite wood products manufacturing facilities in dryers.

Response: The subcategory is not limited to only kiln-dried biomass even though the subcategory is titled as such. As defined in the rule, combustion units designed to burn biomass or bio-based solid fuels may qualify for the Stoker/Sloped Grate/Other unit designed to burn kiln-dried biomass if the unit is either a stoker, sloped grate, or other combustor design and the moisture content of the biomass combusted is less than 20 percent on an annual heat input basis.

7C03. Biomass: Hybrid Suspension/Grate

Commenter Name: David A. Buff, Golder Associates Inc.

Commenter Affiliation: Florida Sugar Industry (FSI)

Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1

Comment Excerpt Number: 8

Comment: The FSI agrees that it is appropriate and necessary for EPA to (a) establish a separate subcategory for hybrid suspension grate boilers designed to combust bagasse and (b) establish corresponding emission limits for PM, TSM, and carbon monoxide ("CO") that are based solely on the performance of the hybrid suspension grate boilers in this subcategory. The FSI's rationale for requesting this subcategory is summarized in the FSI's petition for reconsideration, which was filed with EPA on May 12, 2011. The FSI's petition for reconsideration demonstrates that a hybrid suspension grate boiler fired with bagasse faces

unique challenges that directly affect the boiler's emissions. The unique features of these boilers and their emission profiles warrant a separate subcategory and separate emission limits for PM, TSM, and CO.

Response: The EPA thanks the commenter for their support.

Commenter Name: David A. Buff, Golder Associates Inc.

Commenter Affiliation: Florida Sugar Industry (FSI)

Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1

Comment Excerpt Number: 6

Comment: The FSI agrees with and strongly supports EPA's decision to create additional subcategories for solid fuels, including a subcategory for hybrid suspension grate boilers.

Response: The EPA thanks the commenter for their support.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 64

Comment: Biomass Hybrid Suspension Grate. Hybrid suspension grate boiler means a boiler designed with air distributors to spread the fuel material over the entire width and depth of the boiler combustion zone. The biomass fuel combusted in these units exceeds a moisture content of 40 percent (annual average) on an as-fired basis. The drying and much of the combustion of the fuel takes place in suspension, and the combustion is completed on the grate or floor of the boiler. Fluidized bed, dutch oven, and pile burner designs are not part of the hybrid suspension grate boiler design category. We also request that the 40 percent fuel moisture content cutoff in the hybrid suspension grate subcategory specify that it is for biomass and that it is on an annual average basis in order to acknowledge the variability in biomass moisture content.

Response: The EPA thanks the commenter for their recommended revisions to the definition of the Hybrid Suspension/Grate subcategory. We agree that it is appropriate to define the moisture specification on an annual heat input basis rather than on an as-fired basis due to the inherent variability (i.e., annual basis) of the moisture content and to be consistent with the criteria listed for determining applicability of other subcategories. The specified revisions have been made to the definition in the rule.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 7

Comment: In its Petition for Reconsideration, CIBO requested that the definition of a 'suspension/grate' boiler specifically include the words 'spreader stoker' as a type of combustion system in a suspension/grate boiler in addition to those with independent suspension burners.

The Proposed Reconsideration Rule states that “Stoker means a unit consisting of a mechanically operated fuel feeding mechanism, a stationary or moving grate to support the burning of fuel and admit under-grate air to the fuel, an overfire air system to complete combustion, and an ash discharge system. This definition of stoker includes air swept stokers. There are two general types of stokers: underfeed and overfeed. Overfeed stokers include mass feed and spreader stokers. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, suspension burners, and fuel cells are not considered to be a stoker design.” 76 Fed. Reg. 80,655.

The Proposed Reconsideration Rule also indicates that EPA agrees that “dutch ovens and pile burners should be included in the same subcategory and suspension burners should be a separate subcategory. Therefore, the EPA is proposing separate emission limits for the combustion-based pollutants for these subcategories.” 76 Fed. Reg. 80609.

The Proposed Reconsideration Rule revised the definition of “hybrid suspension grate boiler” to include the italicized sentence:

a boiler designed with air distributors to spread the fuel material over the entire width and depth of the boiler combustion zone. *The fuel combusted in these units exceed a moisture content of 40 percent on an as-fired basis.* The drying and much of the combustion of the fuel takes place in suspension, and the combustion is completed on the grate or floor of the boiler. Fluidized bed, dutch oven, and pile burner designs are not part of the hybrid suspension grate boiler design category.

76 Fed. Reg. 80,652. This revision assists in better defining the source. CIBO recommends that the definition further specify that the moisture content be 40 percent on average, as the precise moisture content will fluctuate somewhat over time. CIBO suggests the addition in red below to the text:

The fuel combusted in these units exceed an average annual moisture content of 40 percent on an as-fired basis.

Response: For a response to the request for the moisture content in the definition of Hybrid Suspension Grate Boiler to be on an annual average basis, please see comment EPA-HQ-OAR-2002-0058-3251-A1, excerpt 64.

7C04. Biomass: Suspension burner

Commenter Name: Mark Weiss

Commenter Affiliation: Reciprocal Energy Company

Document Control Number: EPA-HQ-OAR-2002-0058-3658-A2

Comment Excerpt Number: 1

Comment: While we appreciate the changes reflected in the March 21st Rule Publication, we do not believe that the EPA has considered all of the relevant information pertaining to suspension combustion technology. We agree that suspension combustion should be treated within distinct biomass categories. The new, single, category is however too broad to accommodate significant variations within the suspension combustion field.

Response: The EPA disagrees that the single Suspension Burner subcategory is too broad. The commenter provided no information or data to support this assertion. The EPA does not believe that any significant variations within the Suspension Burner subcategory result in vastly different emission profiles.

Commenter Name: Mark Weiss

Commenter Affiliation: Reciprocal Energy Company

Document Control Number: EPA-HQ-OAR-2002-0058-3658-A2

Comment Excerpt Number: 4

Comment: The biomass fuel used in suspension combustion varies greatly by species and combustion particle size. No allowance is made for these variations yet they are primarily determinate of CO levels.

Response: For response to the claim that the single Suspension Burner subcategory is too broad, please see comment EPA-HQ-OAR-2002-0058-3658-A2, excerpt 1.

Commenter Name: M.L. Steele

Commenter Affiliation: CraftMaster Manufacturing, Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3814-A1

Comment Excerpt Number: 1

Comment: The "Suspension Burners" subcategory should include those units firing fine, dry, biomass particles in suspension that are conveyed in an airstream to the furnace like pulverized coal. This firing method. is described as "True Suspension" on page 15634 of the preamble to the March 21, 2011 final rules. The definition of "Suspension burner" instead describes "fuel distributors" and "injecting air at the point where the fuel is introduced ... in order to spread the fuel material over the boiler width." Also, the biomass fuel is described as "the wet fuel". These terms describe the "Air-swept Stoker". Then the current definition does not clearly include the True Suspension-fired units in the "Suspension Burner" subcategory and should be revised. The requested clarification would make the definition consistent with all the units evaluated by USEPA in the CO and PM MACT Floors. All "Suspension Burner" units are noted in the database as firing dry biomass.

Response: We agree with the commenter that the units evaluated in the MACT floor analysis for this final rule include "True Suspension" boilers as noted by the commenter and that these units are firing dry biomass materials. The references to the wet fuels and air-swept stoker fuel injection mechanisms were inadvertently left in the definition from the June 4, 2010 proposal. At that time, the suspension burner group included both these "True Suspension" units as well as hybrid suspension grate units. Since that proposal the hybrid suspension grate units now belong to a separate subcategory due to fundamental differences in their design. The EPA has revised the definition of suspension burner in the final rule to be consistent with the types of units it included in the data analysis for this subcategory.

7C05. Biomass: Dutch Oven/Pile Burner

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 61

Comment: Within the biomass subcategory, EPA is proposing different CO and PM limits for several boiler types – wet stoker, dry stoker, fluidized bed, fuel cell, and Dutch oven, suspension burner, and hybrid suspension grate units – due to design differences among these types of units. We agree with EPA’s decision to split Dutch ovens and suspension burners for regulation of CO emissions in the proposed rule. Dutch ovens and suspension burners are fundamentally different in design and fuel firing capabilities. Dutch ovens have two chambers. Solid fuel is dropped down into a refractory-lined chamber where drying and gasification take place in the fuel pile. Gases pass over a wall into the second chamber where combustion is completed. Dutch ovens are capable of burning high moisture fuels such as bark, but have low thermal efficiency and are unable to respond rapidly to changes in steam demand. Suspension burners combust fine, dry fuels such as sawdust and sanderdust in suspension. Rapid changes in combustion rate are possible with this firing method. They can be of watertube or firetube design, and may be package units or field-erected. It is not appropriate to combine these two types of boilers for CO standards given their very different characteristics.

Response: The EPA thanks the commenter for their support.

Commenter Name: M.L. Steele

Commenter Affiliation: CraftMaster Manufacturing, Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3814-A1

Comment Excerpt Number: 2

Comment: We question the need for separate subcategories for the Dutch Oven and Fuel Cell combustors. Wellons units are described as Fuel Cells in the literature but are found in the CO MACT Floor evaluations under Dutch Ovens as well as Fuel Cells. Konus units, another pile burner design, are listed in the Fuel Cell subcategory also. Interestingly Konus units also appear in the Stoker/ sloped grate/ other subcategory. These should be evaluated for a possible change in subcategorization.

Response: We disagree with the suggestion that there should be a single subcategory for Dutch Ovens and Fuel Cell combustors. Under CAA section 112(d)(1), the Administrator has the discretion to distinguish among classes, types, and sizes of sources within a category or subcategory in establishing standards. The EPA maintains that, normally, any basis for subcategorization (*i.e.*, class, type, or size) must be related to an effect on HAP emissions that is due to the difference in class, type, or size of the units. Based on the HAP emission data we have on these units, it is appropriate to have separate subcategories for these units. As part of the reconsideration process, we have redone the MACT floor analysis based on new data, corrected data, and changes in inventory. Several facilities which operate combustion units in one of these subcategories submitted comments specifying that their combustion units should be reclassified into another combustor design subcategory. The EPA accepted the comments from these facilities and processed the combustor design changes in the EPA ICR Databases.

7C06. Biomass: Wet Biomass Stoker/Sloped Grate/Other

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 63

Comment: Biomass Wet Stoker/Sloped Grate/Other. Stoker/sloped grate/other unit designed to burn wet biomass means the unit is in the units designed to burn biomass/biobased solid subcategory that is either a stoker, sloped grate, or other combustor design and more than 10 percent of the annual amount of biomass/bio-based solid fuel combusted in the unit exceeds 20 percent moisture (annual average, as-fired), on a heat input basis. The wet biomass stoker/sloped grate/other unit subcategory should be based on units burning at least 10 percent wet biomass on an annual basis (for consistency with other subcategories that have a 10 percent cutoff); the 20 percent moisture content specification should be based on an annual average basis, since the moisture content of dry biomass can vary (for example, lumber mills avoid over-drying the wood, a work practice that minimizes energy use and limits emissions).

Response: The EPA thanks the commenter for their recommended revisions to the definition of the Stoker/sloped grate/other unit designed to burn wet biomass subcategory. We agree that it is appropriate to define the moisture specification on an annual heat input basis due to the inherent variability (i.e., annual basis) of the moisture content and to be consistent with the criteria listed for determining applicability of other subcategories. In the final rule, the definition specifies that the biomass fuel must exceed 20 percent moisture on an annual heat input basis.

7D01. Liquid

Commenter Name: Sarah E. Amick

Commenter Affiliation: Rubber Manufacturers Association (RMA)

Document Control Number: EPA-HQ-OAR-2002-0058-3503-A1

Comment Excerpt Number: 15

Comment: Although EPA set separate emission limits for PM and CO for the light and heavy fuel subcategories, EPA did not set separate limits for Hg and HCl. Hg and HCl are fuel based pollutants. Light liquid fuels include distillate oil, biodiesel and vegetable oil. Heavy liquids include all other liquid fuels that are combusted in boilers, including byproduct liquid fuels generated at industrial facilities and residual oil. Because emissions of Hg and HCl are based on the type of fuel that is combusted, RMA recommends that EPA set separate emission limits for Hg and HCl for the light and heavy fuel subcategories.

Response: The Hg and HCl MACT floor emission limits for liquid boilers in the final rule are calculated from emissions data from both heavy and light liquid fuels. The EPA therefore disagrees with the commenter, as available emissions data show that the two types of fuels can exhibit similar emissions profiles for Hg and HCl. See the memorandum entitle "Revised MACT Floor Analysis (May 2012) for the Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants – Major Source" in the docket.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1
Comment Excerpt Number: 24

Comment: EPA seeks comment on whether Hg and HCl should have limits for heavy and light liquid fuels, not just all liquid. 76 Fed. Reg. 80608. CIBO has supported EPA subcategorizing for light versus heavy liquid fuels in both its comments on the proposed rule and in its Petition for Reconsideration. There are many technical arguments for this sub categorization to separate the liquid fuel units given that HAP content can vary greatly. Furthermore, as CIBO states in its Petition, units can purchase the highest costing liquid fuel available, that provides the lowest PM and CO emission, but cannot meet both the HCl and HG emission limits that EPA is imposing. If units are already using cleaner fuel, EPA should create a standard that holds that as sufficient to meeting limits.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3503-A1, excerpt 15.

Commenter Name: David L. Meeker
Commenter Affiliation: National Renderers Association (NRA)
Document Control Number: EPA-HQ-OAR-2002-0058-3476-A1
Comment Excerpt Number: 7

Comment: EPA should establish a unit designed to burn processed fats subcategory, wholly separate from units designed to burn liquid subcategory due to these units not being similar sources. There are two key definitions in determining the MACT Floor (Boiler MACT).

1. Similar source
2. Achieved in practice

As identified in *Sierra Club v. EPA*, the differentiation of broad source categories into subcategories is provided in the CAA itself, subject to reasonableness in the choice of subcategorization.⁷

Section 112(d)(1) authorizes the Administrator to "distinguish among classes, types and sizes of sources within a category or subcategory," and the language of subsections 112(d)(2) and (3) pervasively refers to standards for sources in each "category or subcategory." The authority to generate subcategories is obviously not unqualified; at the least it must be limited by the usual ideas of reasonableness. [Sierra Club v. EPA]

Following the direction in the CAA, EPA developed a definition for *similar source*.

Similar source means a stationary source or process that has comparable emissions and is structurally similar in design and capacity to a constructed or reconstructed major source such that the source could be controlled using the same control technology. [§63.41]

A separate subcategory is warranted because HAP emissions from petroleum-based liquid fuels include different constituents and are higher than the HAP emissions from processed fats, which

are insignificant, specifically for the metal HAP (including mercury), acid gas HAP (specifically HCl), and organic HAP emissions controlled under the Boiler MACT. The inclusion of processed fats in the broad "unit designed to burn light liquid" subcategory is not warranted due to the insignificant HAP emissions anticipated from the processed fats compared to petroleum-based liquid fuels.

[Footnote 7: *Sierra Club v. EPA* (intervenor Brick Industry Association) (03-1202).]

Response: The EPA disagrees that further subcategorization is necessary for units burning processed fats. Under CAA section 112(d)(1), the Administrator has the discretion to distinguish among classes, types, and sizes of sources within a category or subcategory in establishing standards. The EPA maintains that, normally, any basis for subcategorization (*i.e.*, class, type, or size) must be related to an effect on HAP emissions that is due to the difference in class, type, or size of the units. The EPA believes it is not reasonable to exercise our discretion without such a difference because if sources can achieve the same level of emissions reductions notwithstanding a difference in class, type, or size, the purposes of CAA section 112 are better served by requiring a similar level of control for all such units in the category or subcategory. Even if we determine that emissions characteristics are different for units that differ in class, type, or size, the Agency may still decline to subcategorize if there are compelling policy justifications that suggest subcategorization is not appropriate. Reported fuel analysis data in the EPA ICR Databases show that pollutant constituents in processed fats are similar when compared to other liquid fuels. For these reasons, the EPA does not believe a separate subcategory for units combusting processed fats is warranted.

Commenter Name: David L. Meeker

Commenter Affiliation: National Renderers Association (NRA)

Document Control Number: EPA-HQ-OAR-2002-0058-3476-A1

Comment Excerpt Number: 1

Comment: The Clean Air Act (CAA) Section 112(c)(1) requires emission units located at major source and area source applicable categories to be regulated. Section 112 of the CAA requires that, when setting HAP emission limitations for categories with more than 30 sources, EPA must determine "the average emission limitation achieved by the best performing 12% of the existing sources."

Where fewer than 30 sources exist in a category, EPA should rely upon "the average emission limitation achieved by the best performing five sources." However, before EPA can use the best performing five sources in setting its standard, it is required to analyze all sources "for

which the Administrator has or could reasonably obtain emissions information." The purpose of Section 112(d)(3) of the CAA is to establish the MACT Floor based on the top performers in the industry. Only by first adequately examining the entire industry can EPA evaluate which sources are among the best in their class.

EPA has gathered data for the liquid fuel-fired boiler subcategories (light and heavy) currently defined in NESHAP Subpart DDDDD. This data can then be used to craft an additional subcategory MACT Floor that complies with the requirements of the statute. Since EPA is not limited in establishing a specific total of subcategories for regulation under NESHAP Subpart DDDDD, the NRA is requesting a separate subcategory for units burning processed fats.

Response: For a response to the request for an additional subcategory for units burning processed fats, please see comment EPA-HQ-OAR-2002-0058-3476-A1, excerpt 7.

Commenter Name: David L. Meeker

Commenter Affiliation: National Renderers Association (NRA)

Document Control Number: EPA-HQ-OAR-2002-0058-3476-A1

Comment Excerpt Number: 2

Comment: NRA is submitting the request for a new "units designed to burn processed fats" subcategory under NESHAP Subpart DDDDD based on EPA's determination of the aforementioned proposed rule comment from an NRA member (Darling International Inc.).⁵ The proposed rule comment requested that processed fats not be considered as a solid waste, but instead a biomass solid fuel potentially subject to NESHAP Subpart DDDDD when burned in a boiler or process heater located at a major HAP source or area source, respectively. EPA noted that they agreed with the comment and subsequently added "liquid biofuels" to the definition of "liquid fuel" in the March 21, 2011 final rule at §63.11237 for NESHAP Subpart JJJJJ only. The NRA agrees with the EPA determination that processed fats are not solid waste, and are not considered a solid fuel (biomass) category under NESHAP Subpart DDDDD as identified in the response.

[Footnote 5: Boiler MACT proposed rule comment (Document Control Number EPA-HQ-OAR-2006-0790-1911.1) submitted by Barr Engineering Company and Darling International Inc.]

Response: For a response to the request for an additional subcategory for units burning processed fats, please see comment EPA-HQ-OAR-2002-0058-3476-A1, excerpt 7.

Commenter Name: David L. Meeker

Commenter Affiliation: National Renderers Association (NRA)

Document Control Number: EPA-HQ-OAR-2002-0058-3476-A1

Comment Excerpt Number: 5

Comment: A liquid fuel includes petroleum products, such as distillate oil, residual oil, any form of liquid fuel derived from petroleum products, on-spec used oil, biodiesel, and vegetable oil. These fuel types, other than vegetable oil, are different than processed fats in both origin and content and result in different HAP emissions when combusted in boilers and process heaters.

Processed fats are obtained from the recycling of animal (livestock) and plant (crop) related byproducts from the food processing industry. Processed fats fuel are utilized in the same liquid fuel-fired boilers that burn petroleum-based liquid fuels. No special designed burners are required for the burning of processed fats in liquid fuel-fired boilers. As identified in this letter, the HAPs content of processed fats are insignificant and similar to the HAPs content of Gas 1 fuels and not petroleum-based liquid fuels.

The NRA requests that the following two definitions be added to §63.7575 for NESHAP Subpart DDDDD.

Processed fats fuel means, but is not limited to, yellow grease, poultry grease, brown grease, tallow oil, and any form of liquid fuel derived from animal and vegetable fats, with less than 0.2% by volume petroleum-based fuel content added for alternative fuel blending requirements.

Unit designed to burn processed fats subcategory includes any boiler or process heater that burns any processed fats fuel, but less than 10 percent coal/solid fossil fuel, less than 10 percent biomass/bio-based solid fuel, and less than 10 percent liquid fuel on an annual heat input basis, either alone or in combination with gaseous fuels.

Response: For a response to the request for an additional subcategory for units burning processed fats, please see comment EPA-HQ-OAR-2002-0058-3476-A1, excerpt 7.

Commenter Name: David L. Meeker

Commenter Affiliation: National Renderers Association (NRA)

Document Control Number: EPA-HQ-OAR-2002-0058-3476-A1

Comment Excerpt Number: 6

Comment: The NRA wants to clarify the incorrect reference in the aforementioned proposed rule comment response and confirm EPA's non-classification of processed fats as a biomass (solid) fuel under the major source rule. Specifically, the comment submitted to EPA by Darling International Inc. (NRA member) focused on processed fats not being defined as solid waste (and subject to CISWI rule) and identified the material as worthy of inclusion within a "biomass" fuel subcategory and definition under the Boiler MACT, NESHAP Subpart DDDDD and Boiler GACT, NESHAP Subpart JJJJJ based on the proposed version of each of those rules, which is admittedly different than the reconsidered version being commented on in this letter. EPA did not define the material as a solid biomass, and the NRA agrees with this determination as the fuel is not a solid fuel with HAP content or combustion characteristics similar to biomass solid fuels.

The NRA confirms processed fats are renewable energy materials derived from vegetable (plants) and animal (livestock) sources that have a short-term carbon cycle. The processed fats periodic availability to displace a fraction of fossil fuel demand makes the fuels a renewable fuel, but does not require processed fats to be defined as a biomass solid fuel. The regulation of processed fats as a biomass fuel under NESHAP Subpart DDDDD will result in NRA member facilities not using this renewable fuel due to more stringent control requirements for biomass fuels compared to other fossil fuels (i.e., petroleum-based liquid fuels).

Response: The EPA thanks the commenter for their support of not classifying processed fats as a solid bio-based fuel. For a response to the request for an additional subcategory for units burning processed fats, please see comment EPA-HQ-OAR-2002-0058-3476-A1, excerpt 7.

Commenter Name: David L. Meeker

Commenter Affiliation: National Renderers Association (NRA)

Document Control Number: EPA-HQ-OAR-2002-0058-3476-A1

Comment Excerpt Number: 8

Comment: Included [see submittal for Table 1] is a summary of six processed fat samples analyzed for the metal HAP content. Specific processed fats analyses available for this comment

letter include yellow grease (three samples), poultry grease (one sample), and tallow (two samples).

The metal HAP content in the processed fats were "non-detect" or below detection levels for each pollutant, except lead and manganese. The NRA assumes the different ASTM analysis methodologies are the reason for the anomalies concerning the lead and manganese content measured in samples. Specifically, the lead and manganese content in the yellow grease No. 2 and tallow No. 2 samples were measured using ASTM D 3683. However, the lead and manganese content in three processed fats samples were measured using ASTM E 1613, and one other sample content was measured using ICAP method. The sample set indicates confidence that the metal content of the processed fats samples is insignificant and is comparable to the metal HAPs emitted from units designed to burn Gas 1 fuels (Gas 1 units) as identified [see submittal for Table 2]. With a similar minimal metal HAP content to Gas 1 units, the processed fats-fired boilers do not result in significant metal HAP emissions required to be subject to emissions limitations under NESHAP Subpart DDDDD.

Response: The fuel analysis samples were not incorporated into the EPA ICR Databases because they could not be attributed to a specific facility. For a response to the request for an additional subcategory for units burning processed fats, please see comment EPA-HQ-OAR-2002-0058-3476-A1, excerpt 7.

Commenter Name: David L. Meeker

Commenter Affiliation: National Renderers Association (NRA)

Document Control Number: EPA-HQ-OAR-2002-0058-3476-A1

Comment Excerpt Number: 10

Comment:

Since the processed fats samples metal HAP emissions are drastically different in type and quantities than the petroleum-based liquid fuels, the boilers burning these two types of fuels are not similar sources. Due to the fuels not being identified as similar sources, the NRA requests that the processed fats be categorized as a separate liquid fuel subcategory.

Response: The fuel analysis samples were not incorporated into the EPA ICR Databases because they could not be attributed to a facility. For a response to the request for an additional subcategory for units burning processed fats, please see comment EPA-HQ-OAR-2002-0058-3476-A1, excerpt 7.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 156

Comment: *EPA SHOULD CLARIFY THE DEFINITION OF LIQUID FUEL*

The definition of "liquid fuel" at § 63.7575 currently includes the words "on-spec used oil," but "on-spec used oil" is not defined in the Final Boiler Rule. Congress recognized that in

establishing air standards to meet requirements in the CAA and RCRA, there may be regulatory overlaps between the two statutes. Congress therefore intended for EPA to minimize, if not eliminate regulatory overlap to the maximum extent practicable and to harmonize requirements so that they are consistent. See, for example, § 112(n)(7) of the CAA and § 1006(b) of RCRA. Based on these Congressional directives, ACC believes that EPA should delete the term “on-spec used oil,” as the Boiler MACT rule fails to define “on-spec,” and instead use the term “used oil” which is a defined term in RCRA at 40 CFR 279.11.

Response: We agree with the commenter that the definition of used oil under RCRA at 40 CFR 279.11 is appropriate and we have removed the phrase on-spec from the definition of liquid fuel in the final rule. This change does not impact the makeup of the subcategories or the MACT floor analysis and does not suggest that used oil is or is not solid waste.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 30

Comment: The 10% liquids allowance in the Gas 2 subcategory should be reflected in the liquid subcategory definitions.

The definitions of “unit designed to burn gas 2 (other) subcategory” and “unit designed to burn liquid subcategory” are provided in Table 1, above. [See submittal for Table 1. Comparison of BPH NESHAP Gas and Liquid Subcategory Definitions]

Under these definitions a boiler or process heater that burns Gas 2 and up to 10% liquid would be in both subcategories, an obviously untenable position. The “unit designed to burn liquid subcategory” definition must be modified to exclude boilers and process heaters meeting the Gas 2 subcategory definition if the 10% allowance is not provided for both gas subcategories as discussed in the previous comment.

Response: The EPA agrees with the commenter's concerns. The definitions of Unit Designed to Burn Gas 2 (Other) Subcategory and Unit Designed to Burn Liquid Subcategory have been revised in the final rule. The EPA believes the revised definitions removes the ability for units to demonstrate simultaneous classification within the gaseous and liquid subcategories.

Commenter Name: Arthur N. Marin

Commenter Affiliation: Northeast States for Coordinated Air Use Management (NESCAUM)

Document Control Number: EPA-HQ-OAR-2002-0058-3506-A1

Comment Excerpt Number: 16

Comment: New and existing standard-design packaged distillate oil-fired boilers rated greater than 10 MMBtu/h should be subject to the same emissions standards regardless of whether they are located at a major or area source facility. Their emissions performance is a function of product design, not operator discretion.

Response: Comments pertaining to correlating the emission limits in the major source and area source rules are outside the scope of this comment response document. The EPA further notes that section 112(d)(5) provides discretion to establish emissions standards based on generally available control technology in lieu of MACT standards for area sources, but not for major sources.

7D02. Light Liquid

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 22

Comment: EPA has proposed to "separate subcategories for heavy liquid-fired and light liquid-fired units for PM and CO, pollutants that are dependent on combustor design." 76 Fed. Reg. 80,608. CIBO supports creating different subcategories for heavy and light liquid-fired units. Heavy liquid boilers and light liquid boilers have different equipment designs, operations, and emissions. Thus, it is appropriate to create different subcategories for them.

Response: The EPA thanks the commenter for their support.

Commenter Name: Timothy Serie

Commenter Affiliation: American Coatings Association (ACA)

Document Control Number: EPA-HQ-OAR-2002-0058-3502-A1

Comment Excerpt Number: 5

Comment: ACA generally supports the following proposed changes in the Boiler MACT rule:

Proposed separate subcategories for heavy liquid-fired and light liquid-fired units for PM and CO, dependent on combustor design

Response: The EPA thanks the commenter for their support.

Commenter Name: Arthur N. Marin

Commenter Affiliation: Northeast States for Coordinated Air Use Management (NESCAUM)

Document Control Number: EPA-HQ-OAR-2002-0058-3506-A1

Comment Excerpt Number: 24

Comment: The EPA is proposing separate subcategories for heavy liquid-fired and light liquid-fired units in addressing PM and CO emissions that are dependent on combustor design (76 FR 80608). Units that burn light vs. heavy liquid fuels have distinct PM emission profiles, with heavy fuels emitting considerably more PM than lighter fuels. Therefore, NESCAUM supports the creation of heavy and light liquid fuel subcategories for PM emissions in the major source rule.

Response: The EPA thanks the commenter for their support.

Commenter Name: Alicia Meads
Commenter Affiliation: National Association of Manufacturers (NAM)
Document Control Number: EPA-HQ-OAR-2002-0058-3515-A1
Comment Excerpt Number: 8

Comment: The NAM supports the EPA's conclusion that certain additional subcategories are warranted. For example, the EPA's division of the liquid subcategory into light and heavy liquid subcategories for PM and CO is warranted because of the differences in equipment design, operations and emissions between the subcategories.

Response: The EPA thanks the commenter for their support.

Commenter Name: Paul Noe
Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.
Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1
Comment Excerpt Number: 70

Comment: EPA has proposed to divide the liquid subcategory into light and heavy liquid subcategories for PM and CO. From an equipment design and operations standpoint as well as an emissions standpoint, there is a clear distinction between boilers and process heaters firing light liquids versus those that fire heavy liquids. Based on a review of the top performing liquid boilers, however, those that are correctly categorized as liquid boilers are typically firing light liquids such as distillate oil (which is equivalent to home heating oil), which indicates a difference in emissions from heavy versus light liquid boilers. For these reasons, and because not all boilers will be able to fuel switch due to fuel availability, EPA has appropriately subcategorized heavy and light liquid boilers.

Response: The EPA thanks the commenter for their support.

Commenter Name: Vickie Woods
Commenter Affiliation: Division of Air Quality, North Carolina Department of Environment and Natural Resources (NCDENR)
Document Control Number: EPA-HQ-OAR-2002-0058-3663-A2
Comment Excerpt Number: 6

Comment: NC DAQ supports adding new sub-categories to the rule, including the proposed new fuel oil subcategories and solid fuel subcategories due to differences in design and emission characteristics. We agree with EPA to include separate subcategories for units designed to combust light liquid fuel oils and units designed to combust heavy liquid fuel oils.

Response: The EPA thanks the commenter for their support.

Commenter Name: Linda Miller
Commenter Affiliation: New Jersey Department of Environmental Protection (NJDEP)
Document Control Number: EPA-HQ-OAR-2002-0058-3664-A2
Comment Excerpt Number: 1

Comment: We support separate categories for heavy fuel oil and light fuel oil for boilers and process heaters.

Response: The EPA thanks the commenter for their support.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 25

Comment: Dividing the liquids subcategory reflects real differences between equipment firing light and heavy liquids.

EPA is proposing to subdivide the current liquid fuels subcategory into separate subcategories for heavy liquid-fired and light liquid-fired BPH for PM and CO, pollutants whose emissions are dependent on combustor design and BPH operation. A single liquid fuels subcategory will remain in place for Hg and HCl, pollutants whose emissions are dependent on fuel composition. Separating subcategories for light and heavy liquid fuels reflects real differences in how light and heavy liquids are handled and differences in fuel system and burner designs associated with the differences in the overall physical properties of the fuel and thus we support this proposed change.

Response: The EPA thanks the commenter for their support.

Commenter Name: David L. Meeker

Commenter Affiliation: National Renderers Association (NRA)

Document Control Number: EPA-HQ-OAR-2002-0058-3476-A1

Comment Excerpt Number: 4

Comment: And thus, by considering liquid biofuels as a light liquid for the Boiler MACT, any boiler or process heater combusting processed fats at a major HAP source is grouped in the "light liquid subcategory" and the "unit designed to burn light liquid subcategory" defined in §63.7575.

The NRA requests that EPA evaluate the impact of this "grouping" and consider the pertinent information presented in this letter that demonstrates that it is both reasonable and technically necessary for EPA to consider processed fats as a separate subcategory that is wholly distinct from petroleum-based oils and other liquid biofuels.

Response: For a response to the request for an additional subcategory for units burning processed fats, please see comment EPA-HQ-OAR-2002-0058-3476-A1, excerpt 7 under the chapter for Liquid.

7D03. Heavy Liquid

Commenter Name: Sarah E. Amick

Commenter Affiliation: Rubber Manufacturers Association (RMA)

Document Control Number: EPA-HQ-OAR-2002-0058-3503-A1

Comment Excerpt Number: 2

Comment: EPA has proposed to divide the liquid subcategory into light and heavy liquid subcategories for PM and CO. From an equipment design and operations standpoint as well as an emissions standpoint, there is a clear distinction between boilers and process heaters firing light liquids versus those that fire heavy liquids. Based on a review of the top performing liquid boilers, however, those that are correctly categorized as liquid boilers are typically firing light liquids such as distillate oil (which is equivalent to home heating oil), which indicates a difference in emissions from heavy versus light liquid boilers. For these reasons, and because not all boilers will be able to fuel switch due to fuel availability, EPA has appropriately subcategorized heavy and light liquid boilers.

Response: The EPA thanks the commenter for their support.

Commenter Name: Sarah E. Amick

Commenter Affiliation: Rubber Manufacturers Association (RMA)

Document Control Number: EPA-HQ-OAR-2002-0058-3503-A1

Comment Excerpt Number: 3

Comment: Residual fuel oils typically contain higher levels of ash and somewhat higher levels of metals than do distillate fuel oils. The combination of these characteristics means that residual fuel oil-fired boilers and process heaters have higher emissions of metal HAPs and PM than boilers and process heaters burning distillate fuel oils (light liquid fuels).

Response: The EPA acknowledges this comment.

Commenter Name: Sarah E. Amick

Commenter Affiliation: Rubber Manufacturers Association (RMA)

Document Control Number: EPA-HQ-OAR-2002-0058-3503-A1

Comment Excerpt Number: 4

Comment: Residual fuel oils also have significantly different firing properties than do distillate fuel oils. The combustion characteristics of light and heavy liquids are different, because these fuels have very different flow/viscosity and atomization characteristics and different energy contents. As a result of these property differences, at a minimum, heavy fuel oil firing requires different burner tips than are needed when firing lighter fuel oils. The heating value and flame height differences between these fuels may also impose unit design and operating constraints.

Response: The EPA acknowledges this comment.

Commenter Name: Sarah E. Amick

Commenter Affiliation: Rubber Manufacturers Association (RMA)

Document Control Number: EPA-HQ-OAR-2002-0058-3503-A1

Comment Excerpt Number: 5

Comment: Residual fuel-fired boilers must operate a soot blowing cycle on a periodic basis to maintain their heat transfer efficiency, during which opacity and PM levels increase. While the database does not appear to include any data characterizing soot blowing emissions from liquid-fired units, the proposed emission limits would apply during that time and thus these emissions must be considered. It is, therefore, clear that metal HAP and PM emissions at least, distinguish residual fuel-fired units from distillate-fired units. Indeed, EPA recognized this fact by creating an implicit subcategory for residual-fuel fired units in the rule by requiring in § 63.7525 that residual oil-fired process heaters and boilers (but not distillate units) install a PM CPMS.

Thus, from an equipment design and operations standpoint as well as an emissions standpoint, there is a clear distinction between boilers and process heaters firing light liquids versus those that fire heavy liquids.

Response: The EPA thanks the commenter for their support.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 26

Comment: *EPA Has Appropriately Subcategorized Light-Liquid and Heavy-Liquid Fuels.*

From the available data, there is a difference in emissions of PM and CO from heavy and light liquid units. Residual fuel oils typically contain higher levels of ash and somewhat higher levels of metals¹⁰ than do distillate fuel oils. The combination of these characteristics means that residual fuel oil-fired boilers and process heaters have higher emissions of metal HAPs and PM than boilers and process heaters burning distillate fuel oils (light liquid fuels). [Footnote 10: See AP-42 factors for oil firing, Section 1.3.1. However, HAP metals content in residual fuel oil is strongly influenced by crude oil processed at a given refinery, because these metals volatilize only at very high temperatures and thus typically stay in the bottoms in crude units or in Vacuum units. Thus, the level of metals in a crude oil will be directly related to the metals in residual fuel oil.]

Response: The EPA thanks the commenter for their support.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 27

Comment: Residual fuel oils also have significantly different firing properties than do distillate fuel oils. The combustion characteristics of light and heavy liquids are different, because these fuels have very different flow/viscosity and atomization characteristics and different energy contents. Per AP-42, typical residual fuel has about 7% more energy per gallon than a distillate fuel oil. As a result of these property differences, at a minimum, heavy fuel oil firing requires different burner tips than are needed when firing lighter fuel oils. The heating value and flame height differences between these fuels may also impose unit design and operating constraints.

Response: The EPA acknowledges this comment.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 28

Comment: In addition, residual fuel-fired boilers must operate a soot blowing cycle on a periodic basis to maintain their heat transfer efficiency, during which opacity and PM levels increase. While the liquids database does not appear to include any data characterizing soot blowing emissions, the proposed emission limits would apply during that time and thus these emissions must be considered. It is, therefore, clear that metal HAP and PM emissions distinguish residual fuel-fired units from distillate-fired units. Indeed, EPA has recognized this fact by creating an implicit subcategory for residual-fuel fired units in the rule by requiring in §63.7525 that residual oil-fired process heaters and boilers (but not distillate units) >250 MMBtu/hr install a PM CPMS.

Thus, from an equipment design and operations standpoint as well as an emissions standpoint, there is a clear distinction between boilers and process heaters firing light liquids versus those that fire heavy liquids. EPA has appropriately subcategorized these units.

Response: The EPA thanks the commenter for their support.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 71

Comment: Residual fuel oils typically contain higher levels of ash and somewhat higher levels of metals³⁸ than do distillate fuel oils. The combination of these characteristics means that residual fuel oil-fired boilers and process heaters have higher emissions of metal HAPs and PM than boilers and process heaters burning distillate fuel oils (light liquid fuels).[Footnote 38: See AP-42 factors for oil firing, Section 1.3.1. However, HAP metals content in residual fuel oil is strongly influenced by crude oil processed at a given refinery, because these metals volatilize only at very high temperatures and thus typically stay in the bottoms in crude units or in Vacuum units. Thus, the level of metals in a crude oil will be directly related to the metals in residual fuel oil. AP-42, Volume I, Fifth Edition, Section 1.3.1, <http://www.epa.gov/ttn/chief/ap42/>]

Response: The EPA acknowledges this comment.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 72

Comment: Residual fuel oils also have significantly different firing properties than do distillate fuel oils. The combustion characteristics of light and heavy liquids are different, because these

fuels have very different flow/viscosity and atomization characteristics and different energy contents. As a result of these property differences, at a minimum, heavy fuel oil firing requires different burner tips than are needed when firing lighter fuel oils. The heating value and flame height differences between these fuels may also impose unit design and operating constraints.

Response: The EPA acknowledges this comment.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 73

Comment: Residual fuel-fired boilers must operate a soot blowing cycle on a periodic basis to maintain their heat transfer efficiency, during which opacity and PM levels increase. While the database does not appear to include any data characterizing soot blowing emissions from liquid-fired units, the proposed emission limits would apply during that time and thus, these emissions must be considered. It is, therefore, clear that metal HAP and PM emissions at least, distinguish residual fuel-fired units from distillate-fired units. Indeed, EPA recognized this fact by creating an implicit subcategory for residual oil-fired units in the rule by requiring in § 63.7525 that residual oil-fired process heaters and boilers (but not distillate units) install a PM CPMS.

Thus, from an equipment design and operations standpoint as well as an emissions standpoint, there is a clear distinction between boilers and process heaters firing light liquids versus those that fire heavy liquids.

Response: The EPA thanks the commenter for their support.

Commenter Name: Kevin Bloomer

Commenter Affiliation: Westlake Chemical Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3535-A2

Comment Excerpt Number: 1

Comment: Westlake supports the development and implementation of separate emission limits for the multiple fuel categories.

Response: The EPA thanks the commenter for their support.

Commenter Name: Dakota Gasification Company Great Plains Synfuels Plant

Commenter Affiliation: David W. Peightal

Document Control Number: EPA-HQ-OAR-2002-0058-3424

Comment Excerpt Number: 3

Comment: EPA should consider allowing an additional subcategory of heavy liquid fuels that combust residual fuels or byproducts to meet the non-continental liquid units CO limit of 18 ppm limit or a 91 ppm limit with an averaging time of 10 days or increase the CO limit for units that combust residual fuels or byproducts to something more applicable to the type of fuels combusted.

Response: The EPA disagrees that separate subcategorization is needed for units combusting process-specific residual-type liquid fuels. The EPA ICR Databases contain emissions data from these units, and the EPA must set emissions limitations based on emissions information available to the Administrator. Based on the data, CO emissions limits were calculated for CO for the heavy liquid subcategory. The EPA established the non-continental liquid subcategory because the non-continental liquid units face several unique challenges that prohibit them from operating similarly to continental liquid units.

Commenter Name: Frank H. Thorn

Commenter Affiliation: Newport News Shipbuilding

Document Control Number: EPA-HQ-OAR-2002-0058-3548-A2

Comment Excerpt Number: 23

Comment: In direct response to EPA's specific request for "comment on whether additional subcategories are appropriate", as alternatives NNS proposes the following:

(1) NNS requests that EPA amend §63.7499 of the Boiler MACT by adding a new subcategory for test steam boilers and that EPA simultaneously establish limited, corresponding requirements for the new test steam boiler subcategory by amending §63.7500, as follows: §63.7499 (t) Test steam boilers used to provide steam for testing the propulsion systems on military vessels. §63.7500 ([paragraph number as appropriate]) Test steam boilers must complete a tuneup as specified in §63.7540 prior to each period of vessel steaming. They are not subject to the emission limits in Tables 1 and 2 to this subpart, the annual tune-up requirement in Table 3 to this subpart, or the operating limits in Table 4 to this subpart.

(2) Or, in the alternative, NNS requests that EPA affirm that NNS' FTFSF test steam boilers are exempt from the Boiler MACT pursuant to the provision at 40 CFR §63.7491(c), in that the FTFSF is test equipment used for research and development.

(3) Or, in the alternative, NNS requests an Applicability Determination by EPA that affirms that NNS' FTFSF test steam boilers are not within the class of industrial, commercial, or institutional boilers that EPA studied in its development of MACT Subpart DDDDD regulations and that EPA intended to regulate under Subpart DDDDD, and accordingly that NNS' FTFSF test steam boilers are not to be included among the sources affected by Subpart DDDDD.

Response: In the final rule, the exemption for boilers or process heaters used specifically for research and development has been revised to clarify that test steam boilers used to provide steam for testing the propulsion systems on military vessels are included in the definition. Please see §63.7491 for the exemption.

Commenter Name: Frank H. Thorn

Commenter Affiliation: Newport News Shipbuilding

Document Control Number: EPA-HQ-OAR-2002-0058-3548-A2

Comment Excerpt Number: 1

Comment: The NNS Floating Test Steam Facility (FTFSF) boilers are marine boilers utilized in a unique manner and are not designed, constructed or operated like industrial, commercial or

institutional boilers. The NNS FTFSF marine boiler facility is the only one of its kind, a unique tool designed to test the steam systems of nuclear powered aircraft carriers after new construction or refueling and overhaul. This facility is unique to NNS, because NNS is the nation's sole manufacturer and refueler of nuclear-powered aircraft carriers. The FTFSF boilers are marine boilers, not conventional industrial boilers. They were manufactured by Combustion Engineering in 1977 and were originally designed and built for shipboard use to propel a bulk oil cargo ship. The FTFSF marine boilers are floating, barge-mounted units. The FTFSF barge includes integral storage of over 500,000 gallons of No. 6 fuel oil below deck. While the FTFSF marine boilers are operating, the FTFSF barge can be resupplied with No. 6 fuel oil from a fuel delivery barge at fuel flow rates exceeding 3,000 gallons per minute. Marine boilers in general have characteristics of design, construction and operation which differ considerably from those of conventional industrial, commercial or institutional boilers.

Response: The EPA acknowledges this comment. For a response to the request for an exemption for the NNS Floating Test Steam Facility boilers and corresponding changes to rule language, please see comment EPA-HQ-OAR-2002-0058-3548-A2, excerpt 23.

Commenter Name: Frank H. Thorn

Commenter Affiliation: Newport News Shipbuilding

Document Control Number: EPA-HQ-OAR-2002-0058-3548-A2

Comment Excerpt Number: 2

Comment: The NNS Floating Test Steam Facility (FTFSF) boilers are marine boilers utilized in a unique manner and are not designed, constructed or operated like industrial, commercial or institutional boilers.

The FTFSF marine boilers are designed to achieve exceptionally high "ramping rates". "Ramping rate" refers to a boiler's ability to respond within seconds to minutes to drastic load transients (changes in steam demand), as would be experienced when a ship is maneuvering (e.g., when a carrier is conducting flight operations). The FTFSF marine boilers meet the following Navy performance requirements (among others which cannot be identified here for national security reasons):

- a. Meet transient loads of a baseload of 20,000 Lb/hr increasing to 100,000 Lb/hr in 2 minutes.
- b. Meet transient loads of a baseload of 20,000 Lb/hr increasing to 200,000 Lb/hr in 4 minutes.
- c. Increase load in 100,000 Lb/hr increments in 45 seconds.
- d. Decrease load from 100% to 0% in 35 seconds.
- e. Transient load change shall be accomplished without a boiler shutdown or delivered steam pressure dropping below 580 psig (pounds per square inch gauge).

Response: The EPA acknowledges this comment. For a response to the request for an exemption for the NNS Floating Test Steam Facility boilers and corresponding changes to rule language, please see comment EPA-HQ-OAR-2002-0058-3548-A2, excerpt 23.

Commenter Name: Frank H. Thorn
Commenter Affiliation: Newport News Shipbuilding
Document Control Number: EPA-HQ-OAR-2002-0058-3548-A2
Comment Excerpt Number: 3

Comment: The NNS Floating Test Steam Facility (FTSF) boilers are marine boilers utilized in a unique manner and are not designed, constructed or operated like industrial, commercial or institutional boilers.

The steam pressure and temperature must be maintained in line to the aircraft carrier during “24/7” testing, as well as when there is no user demand for up to 2 weeks. Industrial boilers would be shut down in such cases. The FTSF marine boilers cannot be shut down and must be maintained in a “ready” state at all times.

Response: The EPA acknowledges this comment. For a response to the request for an exemption for the NNS Floating Test Steam Facility boilers and corresponding changes to rule language, please see comment EPA-HQ-OAR-2002-0058-3548-A2, excerpt 23.

Commenter Name: Frank H. Thorn
Commenter Affiliation: Newport News Shipbuilding
Document Control Number: EPA-HQ-OAR-2002-0058-3548-A2
Comment Excerpt Number: 4

Comment: The NNS Floating Test Steam Facility (FTSF) boilers are marine boilers utilized in a unique manner and are not designed, constructed or operated like industrial, commercial or institutional boilers.

The steam generated by the FTSF marine boilers undergoes proprietary feedwater treatment, superheating and desuperheating to produce steam meeting the Navy’s steam flow and quality specifications, including both purity (ppm solids) and moisture content (% moisture) limits, necessary to protect the specialized equipment onboard the aircraft carrier.

Response: The EPA acknowledges this comment. For a response to the request for an exemption for the NNS Floating Test Steam Facility boilers and corresponding changes to rule language, please see comment EPA-HQ-OAR-2002-0058-3548-A2, Excerpt 23.

Commenter Name: Frank H. Thorn
Commenter Affiliation: Newport News Shipbuilding
Document Control Number: EPA-HQ-OAR-2002-0058-3548-A2
Comment Excerpt Number: 5

Comment: The NNS Floating Test Steam Facility (FTSF) boilers are marine boilers utilized in a unique manner and are not designed, constructed or operated like industrial, commercial or institutional boilers.

Many of the specifications governing the steam delivered by the FTSF marine boilers to an aircraft carrier are prohibited from release by NNS. The protections afforded under EPA

regulations at 40 CFR Part 2 Subpart B - Confidentiality of Business Information do not provide the protections required by the U.S. Department of Defense (DoD) and the Naval Nuclear Propulsion Program. The existence of such specifications further underscores the uniqueness of the FTSF marine boilers and sets them apart from boilers providing steam to industrial manufacturing processes.

Response: The EPA acknowledges this comment. For a response to the request for an exemption for the NNS Floating Test Steam Facility boilers and corresponding changes to rule language, please see comment EPA-HQ-OAR-2002-0058-3548-A2, excerpt 23.

Commenter Name: Frank H. Thorn

Commenter Affiliation: Newport News Shipbuilding

Document Control Number: EPA-HQ-OAR-2002-0058-3548-A2

Comment Excerpt Number: 6

Comment: The NNS Floating Test Steam Facility (FTSF) boilers are marine boilers utilized in a unique manner and are not designed, constructed or operated like industrial, commercial or institutional boilers.

The FTSF marine boilers are designed to achieve a higher “turndown” ratio than is typical or necessary of industrial boilers. “Turndown” is defined as the ratio of a burner’s maximum firing capability (in BTU/hr) to the burner’s minimum firing capability (in BTU/hr). High turndown ratios are intended for boilers that must operate over a wide range of capacities or demands, in contrast to industrial boilers that are intended to operate at steadier loads to achieve optimum efficiency. Conventional industrial watertube boilers firing No. 6 fuel oil would be expected to achieve a turndown ratio of no more than about 4:1 (meaning that the boiler cannot be operated below about 25% of full load without combustion becoming unstable and causing the boiler to shut down). The FTSF marine boilers must achieve a much higher turndown ratio to help ensure that the FTSF boilers do not shut off, or “trip”, when operated over a wide range of rapidly varying steam loads.

Response: The EPA acknowledges this comment. For a response to the request for an exemption for the NNS Floating Test Steam Facility boilers and corresponding changes to rule language, please see comment EPA-HQ-OAR-2002-0058-3548-A2, excerpt 23.

Commenter Name: Frank H. Thorn

Commenter Affiliation: Newport News Shipbuilding

Document Control Number: EPA-HQ-OAR-2002-0058-3548-A2

Comment Excerpt Number: 8

Comment: The NNS Floating Test Steam Facility (FTSF) boilers are marine boilers utilized in a unique manner and are not designed, constructed or operated like industrial, commercial or institutional boilers.

The FTSF marine boilers are approximately half of the size of industrial boilers of the same size firing the same fuel. The compact size of these boilers is necessary for the achievement of the

aforementioned high ramping rates and other performance aspects required to meet aircraft carrier testing protocols.

Response: The EPA acknowledges this comment. For a response to the request for an exemption for the NNS Floating Test Steam Facility boilers and corresponding changes to rule language, please see comment EPA-HQ-OAR-2002-0058-3548-A2, excerpt 23.

Commenter Name: Frank H. Thorn

Commenter Affiliation: Newport News Shipbuilding

Document Control Number: EPA-HQ-OAR-2002-0058-3548-A2

Comment Excerpt Number: 9

Comment: The NNS Floating Test Steam Facility (FTSF) boilers are marine boilers utilized in a unique manner and are not designed, constructed or operated like industrial, commercial or institutional boilers.

In conventional use marine boilers are located onboard a vessel and generate steam used by the vessel's propulsion system for moving the ship through the water, by turbine generators for creating electrical power, by water heating systems for personnel and by other steam-driven systems. It is well established that marine boilers used in such a manner are not considered to be stationary sources and are not regulated by EPA as stationary sources. The FTSF operates in an analogous manner and generates steam for the same general purposes, the difference being that the steam generated onboard the FTSF vessel is not delivered to systems onboard the FTSF as described above, but rather is delivered by flexible piping to the same types of systems onboard an adjacent vessel, an aircraft carrier.

Response: The EPA acknowledges this comment. For a response to the request for an exemption for the NNS Floating Test Steam Facility boilers and corresponding changes to rule language, please see comment EPA-HQ-OAR-2002-0058-3548-A2, excerpt 23.

Commenter Name: Frank H. Thorn

Commenter Affiliation: Newport News Shipbuilding

Document Control Number: EPA-HQ-OAR-2002-0058-3548-A2

Comment Excerpt Number: 10

Comment: The steam condensate systems of the NNS Floating Test Steam Facility (FTSF) boilers differ materially from those of most industrial boilers. Steam condensate generated on an aircraft carrier during normal operation at sea is recycled to the onboard steam generating system. However, during RCOH the steam condensate will contain small amounts of dissolved and particulate matter as new system components and piping are brought online for the first time and flushed with steam. Many aircraft carrier steam plant components have very low tolerance specifications for any foreign materials, preventing the condensate from being recycled in such cases and requiring that the condensate be dumped for extended time periods. Therefore, the FTSF marine boilers are designed to handle and are operated at the full range of condensate return, from zero (dumping all condensate) to 100 percent (full recycle of all condensate), requiring that the boiler feedwater treatment and supply system be over-engineered to handle once-through feedwater at maximum system flow and requiring that special boiler feedwater

treatment chemistry be utilized. This aspect of operation differs significantly from most industrial, commercial or institutional boiler systems, where the amount of condensate return is designed to be within a certain range and where the boiler's associated feedwater and treatment systems are sized for that given amount of condensate return. Industrial, commercial or institutional boiler systems that achieve a substantial amount of condensate return, for example, are not intentionally over-designed to handle once-through feedwater at zero condensate return, as are the FTFSF boilers. Additionally, the return of less than 100 percent of the steam condensate to the FTFSF boilers significantly reduces the energy efficiency of the boilers, demonstrating the limited value of an energy assessment or boiler tune-ups for the FTFSF boilers. The information provided above demonstrates that the FTFSF marine boilers are not within the class of boilers contemplated by EPA to be regulated in the development of MACT regulations for industrial, commercial, and institutional boilers.

Response: The EPA acknowledges this comment. For a response to the request for an exemption for the NNS Floating Test Steam Facility boilers and corresponding changes to rule language, please see comment EPA-HQ-OAR-2002-0058-3548-A2, excerpt 23.

Commenter Name: Frank H. Thorn

Commenter Affiliation: Newport News Shipbuilding

Document Control Number: EPA-HQ-OAR-2002-0058-3548-A2

Comment Excerpt Number: 11

Comment: The energy efficiency of the NNS Floating Test Steam Facility (FTFSF) boilers is not a factor in their design or operation, and operation at highest efficiency is detrimental to their required performance. Industrial, commercial or institutional boilers and the steam systems they supply are designed to operate at or near peak thermal efficiency and with minimal variation in load when possible. Many such steam plants utilize more than one boiler so that most of the boilers can be "base loaded" to achieve the desired efficiency and steady-state operation goals, while utilizing only one or a few boilers to "float" with the variable portion of the facility's steam load. In stark contrast, the FTFSF steam load is intentionally varied over an extremely wide range to simulate aircraft carrier mission requirements. The sole purpose of the FTFSF marine boilers is to provide steam in direct response to an aircraft carrier's demand for steam during testing of its propulsion systems, which simulates steam demand conditions that would be encountered by the carrier in carrying out its military mission. Therefore, the FTFSF marine boilers are designed and operated to reliably respond to extreme variability in steam loads. Prior to each carrier steaming event, the FTFSF boilers are tuned in a specific manner to ensure that they will meet the steam demand requirements over their full range of operation. They are not intentionally operated or maintained at or near their point of highest efficiency or lowest fuel usage and cost, and to do so would preclude their ability to deliver steam in the manner necessary to successfully conduct propulsion plant testing. Combustion efficiency is not a factor that is, or can reasonably be, considered as an operating parameter while operating the FTFSF marine boilers in accordance with aircraft carrier testing requirements. Although it is feasible to conduct the one-time energy assessment and annual boiler tune-ups required by the Boiler MACT, these studies would yield little information useful to minimizing emissions from the FTFSF marine boilers or for adjusting the operation of the boilers to improve efficiency.

Response: The EPA acknowledges this comment. For a response to the request for an exemption for the NNS Floating Test Steam Facility boilers and corresponding changes to rule language, please see comment EPA-HQ-OAR-2002-0058-3548-A2, excerpt 23.

Commenter Name: Frank H. Thorn

Commenter Affiliation: Newport News Shipbuilding

Document Control Number: EPA-HQ-OAR-2002-0058-3548-A2

Comment Excerpt Number: 12

Comment: The NNS Floating Test Steam Facility (FTSF) marine boilers are used in research and development and should not be subject to the Boiler MACT. The FTSF marine boiler barge is essentially considered to be “a piece of test equipment” for the Navy’s fleet of aircraft carriers. As explained above, the sole purpose of the FTSF marine boilers is to provide “test steam” to an aircraft carrier for a temporary period to test its steam-driven equipment and systems. In fact, during original permitting in 1985 the name of this barge-mounted system was intentionally chosen to be “Floating Test Steam Facility”, reflecting its design and use as test equipment. The use of these boilers qualifies as research and development (R&D), because each RCOH includes the design, installation, testing, evaluation and potential redesign of various propulsion system technologies that have been developed over the 25-year period since the carrier was first commissioned and placed into service. The aircraft carrier cannot be returned to the Navy as a fully operating ship until all newly installed technologies have been successfully operated and certified. The Boiler MACT regulations at §63.7491(c) specifically exempt boilers that are used for research and development. Notwithstanding the fact that the FTSF marine boilers are located at a major source and may appear to fit the definitions of “boiler” and “industrial boiler” contained within the Boiler MACT, NNS believes that its FTSF marine boilers are used for research and development and should be exempt from the Boiler MACT pursuant to the provision at 40 CFR §63.7491(c).

Response: The EPA acknowledges this comment. For a response to the request for an exemption for the NNS Floating Test Steam Facility boilers and corresponding changes to rule language, please see comment EPA-HQ-OAR-2002-0058-3548-A2, excerpt 23.

Commenter Name: Frank H. Thorn

Commenter Affiliation: Newport News Shipbuilding

Document Control Number: EPA-HQ-OAR-2002-0058-3548-A2

Comment Excerpt Number: 13

Comment: The NNS Floating Test Steam Facility (FTSF) marine boilers are portable units and are not stationary sources subject to the Boiler MACT. The Boiler MACT emission limitations are established pursuant to §112 of the Clean Air Act, whose scope of authority is limited to stationary sources. As explained earlier, NNS constructed the FTSF as a portable steam generating facility by mounting two residual oil-fired marine boilers on a specially designed barge. When testing of an aircraft carrier's steam-driven systems is ready to begin, the FTSF barge is moved by tugboat over open water from its storage location and is positioned adjacent to the aircraft carrier at its designated waterfront locations. The steam and condensate piping that connects the FTSF to the aircraft carrier is flexible, and the FTSF floats with the tide and is

subject to wave action while operating. As previously described the FTSF is a vessel. It permanently resides in the James River along the NNS shipyard waterfront, except during periods of dry-docking for hull inspection, hull recoating and repairs, and is used in a portable manner to supply steam to another vessel, also located in the James River. Although NNS obtained an air permit to construct and operate the FTSF boilers in 1985 from the Virginia Department of Environmental Quality (DEQ), it is arguable that the FTSF boilers are not stationary sources and should not have received a permit under the stationary source regulations. NNS believes that the fact that the DEQ issued a minor New Source Review permit for the FTSF boilers does not render this argument moot with respect to Boiler MACT applicability, and that the EPA can properly determine that, for the particular purpose of determining Boiler MACT applicability, the FTSF is not a stationary source subject to the Boiler MACT. Notwithstanding the question of applicability of stationary source regulations to the FTSF boilers in general, it remains that the FTSF boilers reside on a portable barge located in the James River and are utilized in a manner unlike any of the industrial, commercial or institutional boilers examined by EPA during its development of the Boiler MACT regulations or contemplated by EPA for regulation under the Boiler MACT. Furthermore, the FTSF marine boilers are utilized only for a limited period on an intermittent schedule repeating every few years, depending on the Navy's schedule for overhauling its fleet of nuclear aircraft carriers, and the FTSF marine boilers are shut down, relocated and made non-operational in the period between carrier overhauls. The periodic operation of the portable FTSF with intervening shutdown periods of several years is normal for these test steam boilers, which is unlike industrial boilers which usually are operated year-round or annually on a seasonal basis.

Response: The EPA acknowledges this comment. For a response to the request for an exemption for the NNS Floating Test Steam Facility boilers and corresponding changes to rule language, please see comment EPA-HQ-OAR-2002-0058-3548-A2, excerpt 23.

Commenter Name: Frank H. Thorn

Commenter Affiliation: Newport News Shipbuilding

Document Control Number: EPA-HQ-OAR-2002-0058-3548-A2

Comment Excerpt Number: 15

Comment: Retrofitting the NNS Floating Test Steam Facility (FTSF) marine boilers to combust natural gas as a compliance option has not been determined to be safe or feasible. If the FTSF marine boilers combusted natural gas or propane, no numeric emission limits would apply pursuant to the Boiler MACT, and compliance with the Boiler MACT would only require an energy assessment and annual tune-ups. Therefore, NNS is currently evaluating the feasibility of converting its FTSF marine boilers from No. 6 fuel oil to natural gas or propane. The original boiler manufacturer, Combustion Engineering, no longer exists, and its successor owner no longer designs, services or supports marine boilers. Therefore, NNS sought and has retained the services of other firms experienced in steam power generation to assist NNS in its evaluation. After ten months of extensive research, NNS is not able to state at this time that such a fuel conversion can be technically and safely accomplished within allowable timeframes. Significant additional study, including collection of boiler internal temperatures and metallurgical data, will be required before a conversion to a gaseous fuel can be determined to be feasible. Due to the Navy's long term planning and contracts, the FTSF marine boilers are already scheduled for specific aircraft carrier steaming events for at least the next ten years (into the year 2021).

During that 10-year timeframe, the FTSF marine boilers are only shutdown and available for maintenance for three separate limited periods. The Navy's schedule allows very little time to remove the boilers from service, make the fuel conversions, test the modified equipment, and return the boilers to successful operation prior to the next scheduled steaming event. For example, combustion of a fuel of a vastly different nature than that for which the FTSF marine boilers were originally designed is not simply a matter of replacing the oil burners with gas burners, but rather requires detailed engineering studies and boiler modifications that will require a significant amount of time to complete. Examples of matters that must be evaluated and resolved include, among others:

- fuel combustion aspects (e.g., differences in gas flame size and shape compared to oil; potential impingement of the gas flame causing damage to the waterwall tubes due to the short firebox design of these boilers; and differences in radiative and convective heat transfer characteristics of the gas flame which presents a possibility of out-of-range operating temperatures in the main combustion zone, the superheater tubes and the main steam generating tubes);
- the need for a thorough inspection of the boilers' internals to determine the boilers' ability to withstand changes in combustion characteristics and internal operating temperatures;
- practical limits on achievable volumetric heat release rate within the existing furnace firebox;
- the potential need for an economizer to allow for any required reduction in burner size driven by the aforementioned heat release rate limitation issues;
- achievable turndown ratio;
- the availability of natural gas in the quantities needed and without supplier interruption during seasonal high-demand periods concurrent with carrier steaming operations;
- the ability of the FTSF marine boilers to meet NSPS Subpart Dc industrial boiler emission limits for NO_x;
- the feasibility of adding post-combustion NO_x controls (such as selective catalytic reduction, or "SCR") if the NSPS Subpart Dc NO_x emission limit cannot be directly achieved by the FTSF marine boilers through burner design and combustion control;
- whether combustion control driven by NO_x emission concerns will affect the ability of the boilers to meet Navy transient steam load specifications;
- the safety of using natural gas in boilers not designed for gaseous fuel; and
- the safety of using natural gas below deck in a barge with numerous confined spaces and ignition sources.

NNS has not yet been able to determine the feasibility of conducting the above work and successfully converting the FTSF marine boilers to gas-1 subcategory units without delaying the Navy's RCOH schedule. Also, NNS cannot yet fully determine the cost of converting the FTSF marine boilers to gas-1 subcategory units, because most of the concerns described above have not yet been resolved. Regardless of the ultimate estimated cost, if add-on SCR emission control equipment were ultimately required to meet NSPS Subpart Dc NO_x emission limits, the cost of

conversion of the FTSF marine boilers to the gas-1 subcategory would be increased by another \$1.5 million to \$2.0 million.

Response: The EPA acknowledges this comment. For a response to the request for an exemption for the NNS Floating Test Steam Facility boilers and corresponding changes to rule language, please see comment EPA-HQ-OAR-2002-0058-3548-A2, excerpt 23.

Commenter Name: Frank H. Thorn

Commenter Affiliation: Newport News Shipbuilding

Document Control Number: EPA-HQ-OAR-2002-0058-3548-A2

Comment Excerpt Number: 16

Comment: Conversion of the NNS Floating Test Steam Facility (FTSF) marine boilers to natural gas or propane would also introduce a fuel availability risk that currently does not exist. Because the existing FTSF contains onboard storage of approximately 500,000 gallons of No. 6 fuel oil, fuel is delivered by the supplier on a periodic basis even though it is being combusted continuously. Fuel delivery delays due to adverse weather conditions or other reasons can be reasonably accommodated without risking interruption of boiler operations and carrier steaming. However, natural gas or propane cannot be stored onsite or onboard the FTSF and must be delivered by pipeline directly to the boiler burners on a continuous, “as-burned” basis. Even a momentary interruption of the gas supply at any point along approximately two miles of pipeline would cause the boilers to immediately shut down and disrupt carrier steaming. Steaming tests of particular equipment and systems run continuously for periods of several days up to a few weeks; interruption of one of these tests would likely require that the test be restarted and entirely repeated. If NNS were to attempt to mitigate this risk by constructing an onsite, compressed gas storage system, the storage system itself would introduce additional safety risks and building code requirements that could prevent or prohibit its construction. Thus, conversion of the FTSF marine boilers to gas-1 subcategory units would force NNS and the Navy to operate at a higher risk of interruption of carrier steaming than is currently experienced. A leak of fuel oil at a flange, valve or vent onboard the FTSF is immediately visible, is limited in extent by the viscosity of the liquid fuel, is not flammable, is relatively safe and simple to clean up with absorbent obtained from the onboard spill kit, and results in no downtime or interruption of boiler operations. In contrast a leak of natural gas is not visible, cannot be seen or heard, is extremely flammable, and presents an explosion potential because the FTSF contains numerous confined spaces, as shown by many of the photographs in Exhibit 4. [See submittal for Exhibit 4]. Furthermore, the lower levels of the FTSF boilers are located below deck and provide numerous potential ignition sources. Even if a leak were to occur with no ignition, immediate shutdown and evacuation of personnel from the FTSF would be required, and confined space regulations would require an exhaustive evaluation of gas levels within all compartments in the FTSF before reoccupancy would be allowed. The FTSF boilers would also need to be purged and restarted, and extensive downtime would result. The use of a gaseous fuel in the FTSF boilers, therefore, presents significant safety concerns that NNS would have to resolve, necessitating thorough study and renovation of the barge as well as the boilers.

Response: The EPA acknowledges this comment. For a response to the request for an exemption for the NNS Floating Test Steam Facility boilers and corresponding changes to rule language, please see comment EPA-HQ-OAR-2002-0058-3548-A2, excerpt 23.

Commenter Name: Frank H. Thorn
Commenter Affiliation: Newport News Shipbuilding
Document Control Number: EPA-HQ-OAR-2002-0058-3548-A2
Comment Excerpt Number: 17

Comment: NNS must ultimately obtain agreement from the Navy that the steam delivered to its aircraft carriers from a significantly altered boiler system would continue to be acceptable to the Navy in all respects. This certification process would require six months to complete, which has a significant potential to delay the steaming of the next aircraft carrier, which is already scheduled and under contract with the Navy. To complicate matters further, the FTSF boiler manufacturer, Combustion Engineering, no longer exists, having been purchased in 1990 and its divisions subsequently acquired by several other companies in later years. As a result of the above circumstances, NNS has not yet been able to confirm definitively that the conversion of its FTSF marine boilers to natural gas or propane is feasible and, therefore, NNS cannot yet commit to conversion to natural gas or propane as its means of achieving compliance of the FTSF marine boilers with the Boiler MACT. NNS continues to diligently and in good faith evaluate the feasibility of this Boiler MACT compliance option.

Response: The EPA acknowledges this comment. For a response to the request for an exemption for the NNS Floating Test Steam Facility boilers and corresponding changes to rule language, please see comment EPA-HQ-OAR-2002-0058-3548-A2, excerpt 23.

Commenter Name: Frank H. Thorn
Commenter Affiliation: Newport News Shipbuilding
Document Control Number: EPA-HQ-OAR-2002-0058-3548-A2
Comment Excerpt Number: 19

Comment: NNS believes that EPA was unaware of the significant distinction between the NNS Floating Test Steam Facility (FTSF) boilers and the class of industrial, commercial and institutional boilers targeted by the Boiler MACT and that EPA did not specifically intend to regulate the FTSF boilers as industrial boilers. On June 19, 2009, NNS received a “§114 letter” from EPA pursuant to an information collection request (ICR), OMB Control No. 2060-0616, requiring emissions and fuel testing on one of the FTSF test steam boilers at NNS, specifically Unit ID FTSF-E1. On July 24, 2009, NNS contacted EPA’s Office of Air Quality Planning and Standards (OAQPS) by telephone and requested approval to substitute an NNS industrial steam boiler for Unit FTSF-E1. In that telephone conversation NNS explained to EPA that Unit FTSF-E1 is a No. 6 fuel oil-fired “test steam boiler” which is used intermittently to supply temporary steam to nuclear-powered aircraft carriers in order to test onboard steam-driven machinery before the nuclear propulsion system is made operational. NNS further explained that Unit FTSF-E1 is bargemounted to facilitate placement in proximity to aircraft carriers at several locations throughout the shipyard, and would not be appropriate to test pursuant to the ICR. NNS thus proposed to substitute one of its NNS No. 6 fuel oil-fired facility Powerhouse steam boilers for this testing. At the conclusion of that conversation EPA approved NNS’ proposal to substitute one of the facility steam boilers for Unit FTSE1. This telephone conversation was memorialized in a follow-up email to OAQPS on July 27, 2009 (copy provided in Exhibit 5 below). [See submittal for Exhibit 5] During EPA’s subsequent review of the voluminous

amount of data it most certainly obtained from the ICR and its development of the Boiler MACT regulations ultimately proposed on March 21, 2011, NNS believes EPA overlooked its early determination that the FTSF test steam boilers were not conventional industrial steam boilers and should not have been included among the class of industrial, commercial or institutional boilers considered for regulation pursuant to the Boiler MACT.

Response: The EPA acknowledges this comment. For a response to the request for an exemption for the NNS Floating Test Steam Facility boilers and corresponding changes to rule language, please see comment EPA-HQ-OAR-2002-0058-3548-A2, excerpt 23.

Commenter Name: Frank H. Thorn

Commenter Affiliation: Newport News Shipbuilding

Document Control Number: EPA-HQ-OAR-2002-0058-3548-A2

Comment Excerpt Number: 21

Comment: The NNS Floating Test Steam Facility (FTSF) boilers are required for only six additional carrier refueling events, after which they are no longer planned to be necessary. Only six aircraft carriers remain in the Nimitz class which will require refueling during a mid-life RCOH: the USS Abraham Lincoln (CVN-72), the USS George Washington (CVN-73), the USS John C. Stennis (CVN-74), the USS Harry S. Truman (CVN-75), the USS Ronald Reagan (CVN-76), and the USS George H.W. Bush (CVN-77). The new Ford class of carriers, beginning with the Gerald R. Ford (CVN- 78), which is currently under construction, incorporates new technologies and will not require mid-life refueling. In addition nuclear-powered submarines, which in the past have occasionally been steamed by the FTSF, are currently being designed to not require mid-life refueling. Therefore, NNS does not expect that Navy propulsion plant testing procedures will require the FTSF or other source of shore steam after the George H.W. Bush (CVN-77) mid-life RCOH.

Response: The EPA acknowledges this comment. For a response to the request for an exemption for the NNS Floating Test Steam Facility boilers and corresponding changes to rule language, please see comment EPA-HQ-OAR-2002-0058-3548-A2, excerpt 23.

Commenter Name: Frank H. Thorn

Commenter Affiliation: Newport News Shipbuilding

Document Control Number: EPA-HQ-OAR-2002-0058-3548-A2

Comment Excerpt Number: 22

Comment: For the reasons set forth herein, NNS requests that EPA amend the Boiler MACT by adding the following provision to the exemptions in §63.7491: ([paragraph number as appropriate]) Any boiler used to provide steam for testing the propulsion systems on military vessels.

Response: The EPA acknowledges this comment. For a response to the request for an exemption for the NNS Floating Test Steam Facility boilers and corresponding changes to rule language, please see comment EPA-HQ-OAR-2002-0058-3548-A2, excerpt 23.

7D04. Non-Continental Liquid

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 5

Comment: EPA's new non-continental subcategory in particular is unlawful and arbitrary. The subcategory includes units designed to burn liquid fuel located in the State of Hawai'i, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands. EPA advances two arguments for the change. First, it claims some such units "cannot physically access natural gas pipelines," and lack port facilities for delivery of crude oil. 76 Fed. Reg. at 15,635. Second, it claims some units lack access to fresh water and thus rely on "fin fan" cooling systems. *Id.* Although a lack of access to ports, natural gas, and water, might hypothetically justify some subcategory for units that truly lack access, the subcategory EPA has created is far broader. The Agency does not claim that its new subcategory contains only units that lack access to ports, natural gas and water or even that it contains only units that face some of these purported challenges. EPA does not claim, for example, that no units in these areas maintain cooling systems or have access to substantial port facilities. Thus, sources (existing or new) that are not even arguably a different class, type, or size and that are fully capable of meeting more protective limits may be included in the new subcontinental subcategory and excused from achieving limits that should apply to them. By defining the sub-category broadly by geography, rather than the alleged technical differences cited as justification for creating it, EPA acts arbitrarily and unlawfully. Finally, EPA admits that it does not have any emissions data for the newly minted "non-continental subcategory" and simply made up emission standards for these sources based on data from sources in other categories. Because EPA's standards for the sources in the non-continental categories do not reflect the actual performance of the best units in this group, or even purport to reflect such performance, they are unlawful and arbitrary.

Response: The EPA disagrees with the commenters assertion that the non-continental subcategory is arbitrary and unlawful. For the reasons outlined in the preamble to the March 21, 2011 final rule notice (76 FR 15608), the EPA continues to believe subcategorization for the non-continental units is justified. While the commenter asserts that some units in this subcategory will not face such obstacles, it provides no information or analysis, including identifying specific such units, to support this assertion.

The EPA believes that the unique considerations faced by noncontinental units warrant a separate subcategory for these units and the data show that the difference in location causes a difference in emissions apparently due to the fuel that is available for such units; thus, the Agency has maintained such a subcategory in the final amended rule. The EPA agrees with other commenters that the unique considerations faced by non-continental refineries, including a limited ability to obtain alternative fuels that lead to different emissions characteristics, continue to warrant a separate subcategory for these units. The EPA believes that units in this subcategory will comply through the use of cleaner oils or, for PM, through the installation of an ESP.

Via additional data submitted by non-continental units, all emission limitations for the subcategory in the final rule have been calculated from available data from actual units in the subcategory. The limits no longer default to the emissions data from another subcategory.

Commenter Name: Mary Sullivan Douglas
Commenter Affiliation: National Association of Clean Air Agencies (NACAA)
Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1
Comment Excerpt Number: 50

Comment: NACAA notes that EPA's rationale for the establishment of a non-continental liquid subcategory (without emission data for each pollutant) is undercut by the use of continental liquid data for missing pollutant data.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3511-A1, excerpt 5.

Commenter Name: Matthew Todd
Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)
Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2
Comment Excerpt Number: 26

Comment: We support the establishment of a non-continental liquids subcategory, but believe the definition should be revised to 1) allow for variability due to the forced use of liquid fuels not pertinent to most continental units, and 2) make it consistent with the "unit designed to burn liquid subcategory" definition.

1. EPA explained the basis for establishing a non-continental liquids subcategory in the preamble to the March 21, 2011 final rule at 76 Fed. Reg. 15635. In part that discussion states:

... it is clear that the unique design of this type of unit warrants a separate subcategory because design constraints would not enable the sources to meet the same standards, particularly for CO, as stateside units.

We concur with this conclusion. Limitations on fuels available and the design impacts of needing to fire either liquids or gases in non-continental BPH as internal fuel gas supplies vary, makes this group of units a distinct subcategory from the continental liquid fuels subcategories for PM and CO.

2. Unlike the other gas and liquid subcategory definitions, the "unit designed to burn liquid fuel that is a non-continental unit" text refers to the unit design rather than to what it actually burns as the basis for subcategory assignment. [See submittal for Table 1. Comparison of BPH NESHAP Gas and Liquid Subcategory Definitions.] Thus, a non-continental unit that exclusively burns gas 1, but was originally designed to burn liquids, would appear to be in the non-continental liquids subcategory rather than in the gas 1 subcategory, while an identical continental unit would be in the gas 1 subcategory. This inconsistency must be addressed. 3. During times of refinery gas shortages (e.g., during a gas producing unit maintenance outage), some non-continental BPH must burn liquid fuels. Such use of liquids is minimized because of the high relative cost of liquid fuels. None-the-less, an allowance is needed to allow for such liquids firing without causing the BPH to be reclassified to the non-continental liquid subcategory for these short time occurrences.

We recommend the “unit designed to burn liquid fuel that is a non-continental unit” definition be revised to the following.

Unit designed to burn liquid fuel that is a non-continental unit means an industrial, commercial, or institutional boiler or process heater ~~designed to burn liquid fuel meeting the definition of the unit designed to burn liquid subcategory~~ located in the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Response: The EPA thanks the commenter for their support of the non-continental liquid subcategory. The EPA also agrees with the commenter's suggestions for revisions that would make the definition consistent with the "unit designed to burn liquid subcategory" definition in order for non-continental Gas 1 units to be treated consistently in regards to periods of gas curtailment as continental Gas 1 units.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 34

Comment: The definition of “unit designed to burn liquid fuel subcategory” in the proposal specifically notes that “Gaseous fuel boilers that burn liquid fuel during periods of gas curtailment or gas supply emergencies of any duration are also not included in this definition.” The driver for this exclusion appears to be based solely on continental units preferentially burning natural gas delivered via a pipeline, except when unavailable, and allowing such units to remain under the “unit designed to burn gas 1 subcategory” despite the occasional need to burn liquids due to supply disruptions. It is entirely reasonable that subcategory assignment reflect the primary and optimized fuel situation for each BPH.

Although non-continental facilities do not have access to natural gas pipelines, many non-continental units are subject to a comparable situation – they may normally burn and be optimized for gaseous fuel, but must rely on residual fuel oil produced on site when refinery gas supply is disrupted. For example, a boiler or process heater at a non-continental refinery may primarily fire refinery gas, but also fires fuel oil when the refinery gas supply is insufficient, such as during production unit turnarounds at the refinery. This is analogous to continental gaseous fuel units firing oil during periods of natural gas curtailment. However, the proposed “unit designed to burn liquid fuel that is a non-continental unit” definition does not provide a comparable exclusion for liquid firing under this situation. An exemption for liquid firing for non-continental gaseous fuel BPH gas curtailments should be added to the period of gas curtailment or supply interruption definition.

Response: For discussion on suggested revisions to the non-continental liquid unit definition to provide exemptions for gaseous fuel boilers which combust residual oil in periods of gas curtailment, please see comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 26.

Commenter Name: Christopher Coleman

Commenter Affiliation: HOVENSA LLC. , Hess Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3673-A2

Comment Excerpt Number: 2

Comment: As cited in our prior comments, HOVENSA had strongly supported the creation of a non-continental subcategory for the BPH MACT and supports EPA's continued adoption of this subcategory.

Response: The EPA thanks the commenter for their support.

Commenter Name: Lisa Barry

Commenter Affiliation: Chevron Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3687-A2

Comment Excerpt Number: 1

Comment: We appreciate that EPA established an island subcategory to more appropriately take into account island boiler/heater design and operating conditions.

Response: The EPA thanks the commenter for their support.

7E. Boilers Used in Place of Flares

Commenter Name: Mary Sullivan Douglas

Commenter Affiliation: National Association of Clean Air Agencies (NACAA)

Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1

Comment Excerpt Number: 54

Comment: EPA has requested comment on a stakeholder proposal that EPA consider creating a subcategory for units that are installed and used in place of flares that are currently used to combust process gases. The stakeholders also suggested that it would be appropriate to assume that the emissions from process gases diverted from flares to boilers have "zero emissions" for the purposes of classifying the boiler in which they are combusted. Since the process gases must be combusted in either event, they requested that the EPA develop an approach where it uses a concept similar to the emissions averaging provisions, for example, to simply assume that combustion of such process gases in a boiler rather than a flare should not be counted as emissions from the boiler because there is no net increase in emissions. NACAA supports the use of well-controlled closed combustion devices in lieu of open. However, it appears that such devices would be governed by Gas 2 limits. EPA provides an exemption for combustion devices used as pollution control devices where 50 percent of the heat value of the device is provided by the exhaust stream that is being controlled. The stakeholder proposal would effectively remove the 50-percent limit. NACAA believes this is excessive and would substantially eliminate HAP emission reductions in the Gas 2 category.

Response: The EPA agrees with the commenter. No provisions or exemptions have been added to the final rule for boilers which are used in place of flares to combust process gases.

Commenter Name: Arthur N. Marin

Commenter Affiliation: Northeast States for Coordinated Air Use Management (NESCAUM)

Document Control Number: EPA-HQ-OAR-2002-0058-3506-A1

Comment Excerpt Number: 28

Comment: The EPA has also requested comment (76 FR 80617, Section V.M.2) on a proposal to assume that units installed to divert process gases from flares to boilers have “zero emissions” for the purpose of classifying the boiler. The EPA reports that stakeholders support this proposal with the reasoning that process gases will be combusted in either case, and thus there is no net increase in emissions. No net increase in emissions does not equate to “zero emissions.” MACT serves to minimize HAP emissions, not just to result in a net decrease in emissions. The NESCAUM states believe that this would run counter to application requirements under the EPA’s federal regulations and would require changes to those regulations and many state implementation plans. Furthermore, this proposed “zero emissions” assignment implicitly assumes that the flare and boiler would be under the same management, which may not always be the case. NESCAUM does not support this proposal.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3525-A1, excerpt 54.

7Z. Out of Scope: Rationale for Subcategories

Commenter Name: Michael Livermore, Jason Schwartz

Commenter Affiliation: Institute for Policy Integrity, NYU School of Law

Document Control Number: EPA-HQ-OAR-2002-0058-3432-A1

Comment Excerpt Number: 1

Comment: The agency does have discretion to divide sources into subcategories based on differences in class, type, or size.⁵ In a recent concurring opinion, however, Judge Williams cautioned that while section 112 of the Clean Air Act “pervasively refers to standards for sources in each ‘category or subcategory,’ . . . the authority to generate subcategories is obviously not unqualified; at the least it must be limited by the usual ideas of reasonableness.”⁶

The proposed source subcategorizations may not represent the groupings that would lead to the most efficient regulatory program. Subcategorizations should be made to the extent that they increase the rule’s net benefits. Setting separate standards for multiple different subcategories incurs administrative costs: collecting separate information, setting the different standards, and monitoring and enforcing different standards. Such costs are only warranted if different sources face sufficiently different costs or could generate sufficiently different benefits such that setting a unique standard would increase overall net benefits.

EPA should justify any subcategorizations it makes along these ground. Its current explanation for the subcategories begins to address the differing costs and benefits of regulating different existing sources. Retrofitting existing plants with control devices or process changes can be costly, and plants designed for different fuel types may face different retrofit costs and may be able to achieve different levels of emissions reductions. But EPA should be more explicit about the costs and benefits it is weighing in making these determinations, should try to quantify the costs and benefits to the extent possible, and should only propose subcategories for existing sources to the extent that different standards will enhance net benefits.

[Footnote 5: *Sierra Club v. EPA*, 551 F.3d 1019 (D.C. Cir. 2008) ("Congress specifically permitted the Administrator to 'distinguish among classes, types, and sizes of sources within a category or subcategory in establishing such standards.'"), cert. denied by *Am. Chemistry Council v. Sierra Club*, 2010 U.S. LEXIS 2265 (2010) (citing 42 U.S.C. § 7412(d)(1); *NRDC v. EPA*, 489 F.3d 1364, 1375 (D.C. Cir. 2007) ("Because Congress has vested EPA with subcategorization authority under Section 112(c)(1), and its exercise of that authority involves an expert determination, [petitioner] carries a heavy burden to overcome deference to the agency's articulated rational connection between the facts found and the choices made.").]

[Footnote 6: *Sierra Club v. EPA*, 479 F.3d 875, 885 (D.C. Cir. 2007) (Williams, J., concurring) ("Section 112(d)(1) authorizes the Administrator to 'distinguish among classes, types and sizes of sources within a category or subcategory,' and the language of subsections 112(d)(2) and (3) pervasively refers to standards for sources in each '*category or subcategory*.' The authority to generate subcategories is obviously not unqualified; at the least it must be limited by the usual ideas of reasonableness Nonetheless, one legitimate basis for creating additional subcategories must be the interest in keeping the relation between 'achieved' [in the MACT floor analysis] and 'achievable' [in the beyond-the-floor analysis] in accord with common sense and the reasonable meaning of the statute.".)]

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Arthur N. Marin

Commenter Affiliation: Northeast States for Coordinated Air Use Management (NESCAUM)

Document Control Number: EPA-HQ-OAR-2002-0058-3506-A1

Comment Excerpt Number: 15

Comment: As we stated in our August 23, 2010 comments on the proposed rule for area and major source boilers (document control number EPA-HQ-OAR-2002-0058-2893.1, excerpt 1), NESCAUM is concerned by the widely varying emission limits proposed for similar units regulated under section 112 of the CAA. In that comment, NESCAUM urged that the MACT and GACT levels be harmonized across all applicable rules, thus resulting in consistent emission limits for similar units. The EPA's response indicated that calculated emissions limits are a function of data availability based on the best performing sources in each subcategory. NESCAUM agrees that this should be the case, but urges the EPA to only create subcategories and associated emissions limits where sufficient data exist to determine an applicable emissions limitation. Where data are insufficient to properly characterize what sources in a sector could do to improve emissions control (i.e., maximum achievable control technology), NESCAUM urges the EPA to set standards for less refined subcategories that have more emissions and control data available.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Alicia Meads

Commenter Affiliation: National Association of Manufacturers (NAM)

Document Control Number: EPA-HQ-OAR-2002-0058-3515-A1

Comment Excerpt Number: 7

Comment: The CAA unequivocally authorizes the EPA to establish appropriate subcategories of sources. CAA §112(c)(1) instructs EPA to establish "categories and subcategories" of sources for regulation under Section 112. CAA §112(d)(1) then further provides that the EPA "may distinguish among classes, types and sizes of sources within a category or subcategory" when establishing MACT standards. These provisions vest the EPA with the clear authority to group like units for purposes of establishing emissions limitations. Further, the EPA's ability to subcategorize is a key tool in ensuring that MACT floors are achievable. *See Sierra Club v. EPA*, 479 F.3d 875, 884-85 (D.C. Cir. 2007) (Judge Williams' concurrence noting the need to use subcategorization to avoid imposing unreasonable or unachievable MACT floors).

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 60

Comment: EPA has developed subcategories of boilers under the proposed rule by fuel type, and in some cases, boiler type. We believe that it is appropriate to develop subcategories based on these criteria, as it recognizes the differences in boiler design, operation, and emissions. For example, a solid fuel-fired unit having the combustion occur on a grate has different challenges for optimizing the fuel-air ratio than that of a unit in which the combustion occurs in suspension. Combustion on a grate is subject to piling and smoldering that cannot simply be controlled by increasing the amount of excess air, yet can cause CO emissions to spike unexpectedly. The use of subcategorization in the proposed rule is amply supported by the language of the statute, the legislative history, applicable case law, and the Agency's own past practices.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Mary Sullivan Douglas

Commenter Affiliation: National Association of Clean Air Agencies (NACAA)

Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1

Comment Excerpt Number: 13

Comment: NACAA supports the development of subcategories in MACT rule development, where such subcategories are based on meaningful differences in anticipated fuels and unit designs. EPA has received a significant number of comments from sources making general assertions and theoretical arguments in support of additional subcategories; accordingly, the agency has proposed to greatly expand the number of subcategories for several pollutants. NACAA agrees that EPA's proposal to establish four broad categories based on fuel type – coal, biomass, liquid and gas – is reasonable.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Mary Sullivan Douglas

Commenter Affiliation: National Association of Clean Air Agencies (NACAA)

Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1

Comment Excerpt Number: 17

Comment: EPA has the means to objectively evaluate requests for subcategories and should do so for all subcategories incorporated in its rule. It should determine through the use of statistical techniques, such as a T-test of significance, that the emissions performance of each proposed subcategory is in fact significantly different from the broader category or subcategory of which it is a member. If a significant difference is shown, EPA should determine whether the difference is a function of the design of the combustion unit itself or is related to the prevalence of post-combustion controls that can be employed throughout the category. Where EPA determines that the emissions performance of the proposed subcategory is, in fact, significantly different from the broader category and is associated with the design of the combustion chamber itself, rather than post-combustion controls, EPA should compute the arithmetic average of the best performing unit(s). However, unless the proposed subcategory has sufficient data (nominally 50 data points) upon which to determine the variability of performance, EPA should apply the variability factor from the broader category to the arithmetic average of the best source(s) in the new subcategory. Where EPA did not collect emissions data from a representative sample of all units within a proposed subcategory, EPA has no basis to assume that any particular unit is in the top 12 percent of that subcategory. It is therefore insufficient to establish a subcategory on the basis that a particular unit's emissions are greater than the top 12 percent of the broader category.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Shawn Good

Commenter Affiliation: Pennsylvania Chamber of Business and Industry

Document Control Number: EPA-HQ-OAR-2002-0058-3671-A2

Comment Excerpt Number: 3

Comment: The Pennsylvania Chamber supports proposed revisions to the rules that add flexibility and avoid unintentional overreaching, and encourages further clarification to accommodate site- or sector-specific concerns. The proposed revised rules reflect EPA's efforts to add greater flexibility and to recognize site-or sector-specific differences among regulated sources. Notably, the Pennsylvania Chamber supports the proposal of several key subcategories, including distinct subcategories for units combusting light liquid fuels and heavy liquid fuels, and a new subcategory for seasonally-operated boilers. However, several points warrant clarification and/or modification to insure that the intended flexibility is achieved and unintentional overreaching is avoided.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

107A01. Limited Use of Liquids in Gas 1 Units [DENIED PETITIONER ISSUE]

Commenter Name: William C. Herz

Commenter Affiliation: The Fertilizer Institute (TFI)

Document Control Number: EPA-HQ-OAR-2002-0058-3448-A1

Comment Excerpt Number: 2

Comment: The change in the definition of a "Unit designed to burn gas 1 subcategory" unfairly prejudices TFI's members because instead of relying on the "at least 90 percent natural gas and/or refinery gas" threshold to remain in the "Unit designed to burn gas 1 subcategory," owners and operators must now prepare and submit to EPA a site-specific fuel analysis plan and demonstrate that the mercury concentration meets the "other gas 1 fuel" limits. Further, based on conversations with laboratories, TFI members are having difficulties locating laboratories to run the designated mercury analysis specified in Table 6.

Because this change will substantively affect TFI members from both a cost and feasibility standpoint; and was made without discussion in the final *Industrial Boiler Major Source NESHAP*, or providing the public with the ability to comment on it.

TFI formally requests that EPA revert to its proposed definition of this subcategory, namely:

Unit designed to burn gas 1 (NG/RG) subcategory includes any boiler or process heater that burns at least 90 percent natural gas and/or refinery gas on a heat input basis on an annual average.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Russell A. Wozniak

Commenter Affiliation: The Dow Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3449-A1

Comment Excerpt Number: 39

Comment: EPA should republish the definition of Liquid Fuel subcategory from the March 21, 2011 final rule.

EPA's March 21, 2011 Federal Register final rule contains the following definition of Liquid Fuel Subcategory:

Includes any boiler or process heater of any design that burns more than 10 percent liquid fuel and less than 10 percent solid fuel, based on the total annual heat input to the unit.

EPA's December 23, 2011 Federal Register reconsideration proposed rule no longer contains this definition. EPA should include this definition into the final rule to address minor periods of time when a predominantly gas fired boiler needs to burn a very small amount of liquid fuel, such as a natural gas condensate stream. Combusting such a small amount of liquid on an

infrequent basis should not require the boiler to be considered as a "Unit designed to burn liquid fuel".

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Sarah E. Amick

Commenter Affiliation: Rubber Manufacturers Association (RMA)

Document Control Number: EPA-HQ-OAR-2002-0058-3503-A1

Comment Excerpt Number: 1

Comment: Boilers at RMA member facilities combust either natural gas or a combination of natural gas and liquid fuel oils. Although boilers at RMA member facilities mainly burn natural gas, these boilers may also burn more than 10% liquid fuel in a given year and therefore would be classified as either light or heavy fuel boilers. We believe the emission limits for light and heavy fuel boilers remain unachievable. It is evident that major capital investments in add-on control technology will be required for continued use of liquid fuel in RMA member boilers. RMA members may choose fuel switching to natural gas as a compliance option. Because fuel costs are one of the top three costs of doing business, RMA members would like to maintain the option to burn more than 10% liquid fuel per year. The stringent emission limits EPA has proposed for light and heavy liquid fuel boilers would create a competitive disadvantage for tire manufacturing facilities located in the United States.

The U.S. tire manufacturing industry faces a withering economic slump and fierce competition from overseas manufacturers. In the face of such existing economic pressure, the proposed rules would make matters far worse by imposing large costs on U.S. tire manufacturers. We believe that EPA still has a lot of work to do in tailoring the rule so that it protects health and the environment without imposing unnecessary control requirements and corresponding costs.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 154

Comment: ***THE DEFINITION OF UNIT DESIGNED TO BURN GAS 1 SUBCATEGORY SHOULD BE REVISED***

In the Reconsideration Proposal at § 63.7575, EPA defines units designed to burn Gas 1 as:

"any boiler or process heater that burns only natural gas, refinery gas, and/or other gas 1 fuels; with the exception of liquid fuels burned for periodic testing not to exceed a combined total of 48 hours during any calendar year, or during periods of gas curtailment and gas supply emergencies."

EPA then defines oil (liquid) unit as:

"any boiler or process heater that burns any liquid fuel, but less than 10 percent coal/solid fossil fuel and less than 10 percent biomass/bio-based solid fuel on an annual heat input basis, either alone or in combination with gaseous fuels. Gaseous fuel boilers and process heaters that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year or during periods of maintenance, operator training, or testing of liquid fuel, not to exceed a combined total of 48 hours during any calendar year are not included in this definition. Gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply emergencies of any duration are also not included in this definition." In the proposed reconsidered area source rule at 40 CFR 63.11237, EPA defines a gas-fired boiler as —any boiler that burns gaseous fuels not combined with any solid fuels, burns liquid fuel only during periods of gas curtailment, gas supply interruption, startups, or periodic testing on liquid fuel. Periodic testing of liquid fuel shall not exceed a combined total of 48 hours during any calendar year.|| (emphasis added) (76 Fed. Reg. 80547, December 23, 2011)

EPA has consistently used 10% as a threshold for movement from one subcategory to another. For example the most stringent – coal – includes units that burn at least 10% coal. The next – biomass – includes units that burn at least 10% biomass and less than 10% coal. The first sentence of the oil (liquid) subcategory includes any liquid fuel, but less than 10 % solid fuel. Therefore, it logically follows that a plain reading of the Gas 1 subcategory would be that EPA intended to include any unit that burns at least 90% gas and less than 10% of any other fuel. EPA should include an allowance for oil firing in the Gas 1 subcategory definition of 10 percent (as allowed in other subcategory definitions). At a minimum, EPA should make the Gas 1 subcategory definition consistent with the area source definition, which places no restriction on oil firing during startup. A new gas-fired boiler that is designed to burn liquid fuel as backup must be allowed to burn oil for more than 48 hours per year in order to ensure that the oil burners are properly tuned during initial startup.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 155

Comment: ACC proposes the following definition for the Gas 1 subcategory:

"Unit designed to burn gas 1 subcategory includes any boiler or process heater that burns at least 90 percent natural gas, refinery gas, and/or other gas 1 fuels on a heat input basis on an annual average and less than 10 percent of any solid or liquid fuel."

This definition change would simplify the process of determining if a unit qualifies for the gas 1 subcategory and would eliminate the need to determine whether periods during which liquid fuel is fired constitute natural gas curtailment, gas supply emergency, or periodic testing. It would also accommodate the need to be able to burn oil during initial startup in order to test and tune the oil burners on a new unit or an existing unit where new burners have been installed. EPA

already acknowledges in §63.7510(a)(2)(i) that units burning a supplemental fuel for startup, shutdown, and transient flame stability purposes are single fuel units, and the supplemental fuel is not subject to fuel analysis requirements.

This change would also be consistent with how EPA has defined the Gas 2 subcategory (the definition includes an allowance for burning 10 percent liquid fuel):

"Unit designed to burn gas 2 (other) subcategory includes any boiler or process heater that is not in the unit designed to burn gas 1 subcategory and burns any gaseous fuels either alone or in combination with less than 10 percent coal/solid fossil fuel, less than 10 percent biomass/bio-based solid fuel, and less than 10 percent liquid fuels on an annual heat input basis."

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Shannon S. Broome

Commenter Affiliation: Auto Industry Forum (AIF)

Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1

Comment Excerpt Number: 51

Comment: EPA Should Amend the Definition to Permit Such Units to Burn Up to 10% Other Fuels.

In the June 4, 2010, proposal for the Boiler MACT, the definition of "unit designed to burn gas 1 subcategory" was formulated as follows:

Unit designed to burn gas 1 (NG/RG) subcategory includes any boiler or process heater that burns at least 90 percent natural gas and/or refinery gas on a heat input basis on an annual average.

*National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, 75 Fed. Reg. 32,006, 32,065 (June 4, 2010) (the "Proposed Boiler MACT") (underline added). The Boiler MACT Reconsideration Proposal contains the following revised formulation to the definition:*³⁴

Unit designed to burn gas 1 subcategory includes any boiler or process heater that burns only natural gas, refinery gas, and/or other gas 1 fuels; with the exception of liquid fuels burned for periodic testing not to exceed a combined total of 48 hours during any calendar year, or during periods of gas curtailment and gas supply emergencies.

Boiler MACT Reconsideration Proposal, 76 Fed. Reg. at 80,655 (underline added to indicate revisions). AIF supports the proposed exclusion in this definition for periods of time that a NGfired unit combusts fuel oil for testing purposes and when needed as an "emergency back-up" fuel. However, AIF is concerned about the 48-hour restriction associated with "periodic testing" and that gas curtailment and/or gas supply emergencies may not address all of the foreseeable emergency situations. Accordingly, AIF urges EPA to amend this definition to allow units in the Gas 1 category to burn up to 10% other fuels annually, thereby returning to the prior formulation

of the definition from the Boiler MACT Proposal. *See Proposed Boiler MACT*, 75 Fed. Reg. at 32,065.

With respect to the 48-hour restriction for “periodic testing,” consider, for example, the request by a state agency to conduct emission testing using fuel oil to demonstrate compliance with emission limits that would be imposed when combusting fuel oil pursuant to state regulations. In AIF members’ experience, boilers in such a circumstance may have to operate on fuel oil for approximately one week to ensure that they have achieved representative operation to allow for an acceptable emission test using the federal reference test methods. It would be inappropriate to then consider the boiler no longer covered by the NG category because of such emission testing. Thus, while 48 hours may be adequate to confirm that a boiler could operate using fuel oil as designed, it is insufficient to provide adequate operation to perform emission testing when required by a state regulatory agency.

With regard to the exclusion of NG curtailment and/or supply emergencies, AIF members recall events during the 1980’s when there was extensive uncertainty regarding the availability of a continuous supply of NG and fear about potential NG shortages and interruptions. To be clear that fuel oil can be used during periods of inadequate NG supply or interruption, AIF believes that the exception provided in the definition needs to be expanded to allow for periods of potential supply interruption.

Therefore, AIF urges EPA to amend the definition to allow for units in the Gas 1 category to burn up to 10% other fuels annually. If EPA does not revise the definition as AIF urges, it will result in taking units that would otherwise fall within the ambit of this definition – and that are designed to burn Gas 1 – outside of it. There is no rational basis for such a result.

[Footnote 34: The formulation for this definition in the Boiler MACT Reconsideration Proposal is consistent with the formulation in the final rule. *See Boiler MACT*, 76 Fed. Reg. at 15,686.]

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 127

Comment: In the proposed rule at 40 CFR 63.7575, EPA defines units designed to burn Gas 1 as: "any boiler or process heater that burns only natural gas, refinery gas, and/or other gas 1 fuels; with the exception of liquid fuels burned for periodic testing not to exceed a combined total of 48 hours during any calendar year, or during periods of gas curtailment and gas supply emergencies." EPA then defines oil (liquid) unit as: "any boiler or process heater that burns any liquid fuel, but less than 10 percent coal/solid fossil fuel and less than 10 percent biomass/bio-based solid fuel on an annual heat input basis, either alone or in combination with gaseous fuels. Gaseous fuel boilers and process heaters that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year or during periods of maintenance, operator training, or testing of liquid fuel, not to exceed a combined total of 48 hours during any calendar year are not included in this definition.

Gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply emergencies of any duration are also not included in this definition."

In the area source rule at 40 CFR 63.11237, EPA defines a gas-fired boiler as "any boiler that burns gaseous fuels not combined with any solid fuels, burns liquid fuel only during periods of gas curtailment, gas supply interruption, startups, or periodic testing on liquid fuel. Periodic testing of liquid fuel shall not exceed a combined total of 48 hours during any calendar year." (emphasis added)

EPA has been very consistent throughout the proposal to use 10% as a threshold for movement from one subcategory to another. For example the most stringent threshold – coal – includes units that burn at least 10% coal and less than 10% biomass. The next –biomass – includes units that burn at least 10% biomass. The first sentence of the oil (liquid) subcategory includes any liquid fuel, but less than 10% solid fuel.⁵⁶ Therefore, it logically follows that a plain reading of the Gas 1 subcategory would be that EPA intended to include any unit that burns at least 90% gas and less than 10% of any other fuel. EPA should include an allowance for oil firing in the Gas 1 subcategory definition of 10 percent (as allowed in other subcategory definitions).

[Footnote 56: As discussed immediately below, that definition should also be revised to avoid conflict with the current definition of the Gas 2 subcategory (and the definition of the Gas 1 subcategory as we propose it be revised).]

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 128

Comment: At a minimum, EPA should make the Gas 1 subcategory definition consistent with the area source definition, which places no restriction on oil firing during startup. A new gas-fired boiler that is designed to burn liquid fuel as backup must be allowed to burn oil for more than 48 hours per year in order to ensure that the oil burners are properly tuned during initial startup.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 129

Comment: We propose the following definition for the Gas 1 subcategory:

"Unit designed to burn gas 1 subcategory includes any boiler or process heater that burns at least 90 percent natural gas, refinery gas, and/or other gas 1 fuels on a heat input basis on an annual average and less than 10 percent of any solid or liquid fuel."

This definition change would simplify the process of determining if a unit qualifies for the gas 1 subcategory and would eliminate the need to determine whether periods during which liquid fuel is fired constitute natural gas curtailment, gas supply emergency, or periodic testing. It would also accommodate the need to be able to burn oil during initial startup in order to test and tune the oil burners on a new unit or an existing unit where new burners have been installed. EPA already acknowledges in §63.7510(a)(2)(i) that units burning a supplemental fuel for startup, shutdown, and transient flame stability purposes are single fuel units, and the supplemental fuel is not subject to fuel analysis requirements.

This change would also be consistent with how EPA has defined the Gas 2 unit subcategory at §63.7575:

"Unit designed to burn gas 2 (other) subcategory includes any boiler or process heater that is not in the unit designed to burn gas 1 subcategory and burns any gaseous fuels either alone or in combination with less than 10 percent coal/solid fossil fuel, less than 10 percent biomass/bio-based solid fuel, and less than 10 percent liquid fuels on an annual heat input basis."

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Douglas Price

Commenter Affiliation: Tesoro Companies, Inc

Document Control Number: EPA-HQ-OAR-2002-0058-3630-A2

Comment Excerpt Number: 3

Comment: *Include a 10 Percent Liquid Fuel Burning Allowance for the Gas 1 Subcategory*

As discussed in more detail in the API/AFPM comment letter dated February 21, 2012. Tesoro is very concerned about the re-proposed rule's definition of "unit designed to burn gas 1 subcategory."

Previous versions of 40 C.F.R. Subpart DDDDD demonstrate that the EPA has intended to allow gas-fired boilers or process heaters to burn up to 10 percent of liquid fuels on an annual average heat input basis and still remain within a gas-fired subcategory. For example, in the preamble of the March 21, 2011 final 40 C.F.R. Subpart DDDDD rule, it states the following:

"If your facility is located in the continental United States and your new or existing boiler or process heater burns at least 10 percent liquid fuel (such as distillate oil, residual oil) and less than 10 percent coal and less than 10 percent biomass, on an annual average heat input basis, your unit is in the liquid subcategory. "

Also, the current re-proposed 40 C.F.R. Subpart DDDDD rule allows for a 10 percent liquid fuel burning allowance in the definition of "Unit designed to burn gas 2 (other)" which is as follows:

Unit designed to burn gas 2 (other) subcategory includes any boiler or process heater that is not in the unit designed to burn gas 1 subcategory and burns any gaseous fuels either alone or in combination with less than 10 percent coal/solid fossil fuel, less than 10 percent biomass/bio-based solid fuel, and less than 10 percent liquid fuels on an annual heat input basis.

These two references clearly demonstrate EPA's intent to allow for the use of a 10 percent annual heat input allowance for liquid fuel burning. Therefore, this allowance should be included in the "unit designed to burn gas 1 subcategory" definition of the currently re-proposed 40 C.F.R. Subpart DDDDD.

Tesoro owns and operates two refineries located in the continental United States that have the permitted flexibility to burn liquid fuels on a very limited basis. For example, Tesoro's Mandan Refinery's boilers and process heaters primarily burn refinery fuel gas or natural gas. However, one boiler has the capability and is allowed to burn liquid fuel during periods of documented natural gas curtailment *and* as necessary to ensure that the refinery can use fuel oil during periods of natural gas curtailment. With the current design of the fuel oil system, a certain small amount of fuel oil is burned frequently in order to ensure the system is ready and can come online quickly during a curtailment period. Without this small amount of on-going burning, the fuel oil circulation system would be susceptible to plugging and the refinery may not be able to respond quickly in the event of a gas supply emergency. While this fuel oil use amounts to a limited amount of liquid fuel burning on an annual basis, the current definition of "unit designed to burn gas 1 subcategory" would require this practice to stop quickly after 48 hours of a limited amount of liquid fuel being fired. In addition, Tesoro's Anacortes Refinery relies on a limited amount of permitted fuel oil firing in certain units to maintain the safe and reliable operation of the refinery during certain maintenance activities, in addition to natural gas curtailment periods and routine testing.

The inclusion of a 10 percent annual heat input liquid fuel allowance is the more appropriate approach for allowing some level of required liquid fuel burning, but still ensuring the use is limited enough to remain in the gas 1 subcategory.

Recommendation: For the reasons described above, Tesoro requests that the 10 percent annual heat input allowance for liquid fuel burning be included in the "unit designed to burn gas 1 subcategory" definition.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Christopher Coleman

Commenter Affiliation: HOVENSA LLC. , Hess Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3673-A2

Comment Excerpt Number: 3

Comment: While the Reproposed BPH MACT appears to make some effort to make the supply disruption definition applicable to those maintenance or other activities that may cause a temporary increase in oil usage at a non-continental facility, the language is far from clear and is muddled by the "beyond the control" language. HOVENSA suggests that this definition be made applicable by language creating a clear safe harbor, similar to the following:

"For non-continental boilers and process heaters, supply interruption also includes periods where on site supplies of gas fuels are reduced because operations of gas producing process units have been halted or reduced due to turnarounds, maintenance, unanticipated shutdown or gas transmission bottlenecks or disruptions."

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Christopher Coleman

Commenter Affiliation: HOVENSA LLC. , Hess Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3673-A2

Comment Excerpt Number: 4

Comment: HOVENSA supports API/NFPM comments on the application of the 10% allowance. We believe this is necessary and appropriate because units burning small amounts of liquid along with Gas 1 have approximately the same emissions profile and should be treated the same for regulatory purposes. This can be accomplished either by (i) including it in the Gas1 definition or (ii) the "Units designed to burn liquids subcategory" definition and coordinating noncontinental, heavy and light liquid subcategories so that units that are NOT liquid units as defined cannot be in those subcategories. HOVENSA notes that even the relatively simple use of the subcategory descriptions in Table 1 and 2 for solid fuel "Units in all subcategories designed to burn solid fuel" would help make it clearer that the "Units designed to burn liquids subcategory" is the subcategory superset and the light, heavy and non-continental units are subsets of that category.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Christopher Coleman

Commenter Affiliation: HOVENSA LLC. , Hess Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3673-A2

Comment Excerpt Number: 5

Comment: It is essential that both the 10% allowance and the supply curtailment provisions work together to treat non-continental units in a manner similar to mainland units. HOVENSA typically burned far more than 90% refinery fuel gas and propane and far less than 10% liquids in its BPH on an annualized basis. The emissions profile of HOVENSA BPH would be very similar to and have the same emissions measurement issues as do units in the Gas 1 category. The only time this situation changes is a fuel gas supply disruption, primarily if the Coker or FCCU are taken off line for scheduled or unscheduled maintenance. In this case, one or more BPH could switch categories from Gas 1 to Non-continental, and then switch back in a year, creating significant confusion as to what emissions limits and controls might apply and at what time. As our comments and those of API and AFPM have stated, this is essentially the same situation a continental refinery faces when supply of natural gas is curtailed. HOVENSA recommends that fuel oil burned during periods of curtailment not be included in the 10% allowance.

As an alternative, HOVENSA has suggested using a three year averaging period instead of a one year period for determining the 10% threshold. This approach is consistent with the exemption from the EGU category for natural gas fired units, which can average 10% over a three year period.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 28

Comment: The 10% minimum liquid fuel criterion for the “units designed to burn liquid subcategory” was removed in finalizing the March 21, 2011 BPH NESHAP with no explanation or justification and no opportunity for public comment. In fact, that rule preamble indicated the 10% criterion remains. That change is carried through into this proposal. EPA must return that 10% allowance or provide justification for the revision for notice and comment. It also must revise the unit designed to burn gas 1 subcategory definition to reflect the 10% allowance.

Table 1 [See submittal for Table 1. Comparison of BPH NESHAP Gas and Liquid Subcategory Definitions] compares the gas and liquid subcategory definitions from the June 4, 2010 BPH NESHAP proposal, the March 21, 2011 final rule, and the current proposal.

The 10% liquid allowance is contained in the definition of “liquid fuel subcategory” in both the June 4, 2010 original proposal and the March 21, 2011 final rule. It was also contained in the “unit designed to burn oil subcategory” in the original proposal. However, neither of these terms is used in the March 21, 2011 final rule or in the current proposal when imposing requirements (e.g. Tables 1 and 2). Rather the term “unit designed to burn liquid subcategory” is the term used in the final rule and the current proposal and that definition does not contain the 10% allowance.

Similarly, the gas 1 subcategory definition was changed to drop the 10 percent allowance between proposal and final, while the allowance was added to the gas 2 subcategory definition. The final rule gas subcategory definitions were carried forward into this proposal.

On page 15637 of the March 21, 2011 final rule preamble, EPA describes the liquid and gas subcategories as follows.

The subcategories for the combustion based pollutants are now determined in the following manner. ... If your facility is located in the continental United States and your new or existing boiler or process heater burns at least 10 percent liquid fuel (such as distillate oil, residual oil) and less than 10 percent coal and less than 10 percent biomass, on an annual average heat input basis, your unit is in the liquid subcategory. If your non-continental new or existing boiler or process heater burns at least 10 percent liquid fuel (such as distillate oil, residual oil) and less than 10 percent coal and less than 10 percent biomass, on an annual average heat input basis, your unit is in the non-continental liquid subcategory. Finally, for the combustion-based

pollutants, if your unit combusts gaseous fuel that does not qualify as a “Gas 1” fuel, your unit is in the Gas 2 subcategory.

Clearly, the promulgated gas 1 and liquids subcategory definitions did not reflect the preamble descriptions or the proposal relative to the 10% liquids criterion. Since removing the 10% criterion from the gas 1 and continental liquids subcategory and not including it in the non-continental subcategory was not discussed in the record and is not a logical outcome of the proposal, the definitions in the March 21, 2011 BPH NESHAP were not been properly promulgated and the definitions in the current proposal should correct that error or EPA should explain the basis for the change in a new notice and request comment.

The 10% allowance is needed because the testing and gas curtailment exclusions in this proposal and in the March 21, 2011 final rule are inadequate because they do not provide for liquid fuel firing by primarily gas-fired BPH in all the situations where it is necessary or desirable.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 29

Comment: Liquid firing is needed on some typically gas fired BPH in the following situations.

- When refinery gas is curtailed, when the curtailment is due to a situation that might be deemed to be under the control of the facility, such as shutdown or cutback (either planned or unplanned) of a refinery gas producing unit or the gas treating and transport system or where maintenance is needed on the gas system. In most cases, natural gas is used to replace refinery gas when a site refinery gas producer is not available (e.g., undergoing maintenance) or at reduced rates (e.g., because of product demand). However, for non-continental refineries and some continental ones, adequate natural gas supply is not available⁹ and liquids must be used to make-up for a refinery gas shortfall. Under the existing and proposed §63.7575 definition of “period of gas curtailment or supply interruption,” outages of on-site gas production due to process maintenance or product demand mismatch would not be considered curtailments and thus any liquid firing during that period would make the impacted BPH liquid subcategory units rather than gas subcategory units.
- Where liquid fuel is the backup for gas 1 fuel emergency outages, facilities often need to introduce small amounts of liquid continuously into the burner to assure the liquid fuel will be instantaneously available should an emergency or malfunction cause an unexpected loss of fuel gas¹⁰. The 48 hour allowance in the proposal is inadequate for this situation, particularly since most of the 48 hours could be needed for testing and training. Maintaining boiler operation in such emergencies can be critical to avoiding emergency shutdowns of processes and to providing steam to prevent flare smoking.
- In some cases, small amounts of non-hazardous secondary materials are used as supplemental fuel in BPH. Where such fuels meet the criteria in Part 241, such an operation

would be subject to this regulation. Recovery of energy from such streams is environmentally desirable and should be encouraged. Allowing for up to 10% liquids before a BPH is reclassified to the liquid subcategory fosters this energy recovery.

[Footnote 9: For continental refineries, natural gas supply can be limited by delivery piping constraints.]

[Footnote 10 One refinery reports the following configuration. Under normal operating conditions, oil is circulated through a piping loop in which a 1 gpm slipstream is continuously sent to the burners of the boiler to be burned while the remaining oil returns to the storage tank. Oil circulation through the loop with a minimum oil burn rate has allowed this system to remain in standby service should either a natural gas curtailment or fuel gas supply emergency require its use to maintain boiler operation. In the case in which continuous burning is no longer permitted, the oil circulation system would be susceptible to plugging, especially in the stagnant, un-insulated lines and valves. Pluggage of any of these lines or valves would result in a non-operational oil fuel system should it be needed. A reliable and operational oil system could very well save refinery operations in the event of a fuel supply emergency.]

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

107A02. Automatically Include Other Gases in Gas 1 Definition [DENIED PETITIONER ISSUE]

Commenter Name: William C. Herz

Commenter Affiliation: The Fertilizer Institute (TFI)

Document Control Number: EPA-HQ-OAR-2002-0058-3448-A1

Comment Excerpt Number: 8

Comment: TFI requests that EPA revise the *Industrial Boiler Major Source NESHAP* to explicitly recognize purge gas from an ammonia plant as an "other gas 1 fuel" in EPA's regulations without the need for (1) preparation and submission to EPA of a site-specific fuel analysis plan, and (2) sampling and analysis of the purge gas stream to demonstrate that the mercury concentration meets the "other gas 1 fuel" limits. There is no benefit to developing and implementing a sampling plan for this purge gas stream when it is just unreacted desulfurized natural gas in the first instance.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: William C. Herz

Commenter Affiliation: The Fertilizer Institute (TFI)

Document Control Number: EPA-HQ-OAR-2002-0058-3448-A1

Comment Excerpt Number: 9

Comment: As further support for TFI's request, EPA states in the preamble to the Proposed Rule that "The emissions data for natural gas-fired units show the overwhelming majority of

emissions to be below the level that can be accurately quantified by the available test methods." In addition, ammonia plant operators are provided with periodic analyses of the constitution of the natural gas feed; and these indicate that contaminants are typically *de minimus*.

As ammonia plants utilize this purge gas stream which is simply unreacted desulfurized natural gas, TFI requests that an exemption be granted for purge gas utilization in this context.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Peter Pagano

Commenter Affiliation: American Iron and Steel Institute (AISI)

Document Control Number: EPA-HQ-OAR-2002-0058-3490-A1

Comment Excerpt Number: 17

Comment: The definition of "other gas 1 fuels" should be amended so that process gases covered by parts 60, 61, or 63 are covered without demonstrating they contain less than 40 ug/m³ mercury. Members of the iron and steel industry send process gases, including coke oven gas and blast furnace gas, to boilers and process heaters, that are equivalent to, if not superior to traditional environmental controls. They beneficially reuse these gases for their heat content, conserve energy, reduce the use of other fuels in the operation of boilers and process heaters, and reduce overall emissions. Process gases should be accorded the same treatment as natural gas and refinery gas in this provision and the definition of "other gas 1 fuels" in section 63.7575 should be amended to reflect this.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Shannon S. Broome

Commenter Affiliation: Auto Industry Forum (AIF)

Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1

Comment Excerpt Number: 15

Comment: While AIF Supports EPA's Proposal to Eliminate the H₂S Specification, Given Landfill Gas' Relative Equivalence to Natural Gas and Refinery Gas in Relevant Emission Measures, EPA Should Automatically Classify Landfill Gas as a Gas 1 Fuel.

In the reconsideration proposal, EPA does not propose to change the Gas 1 category to automatically include LFG; it still proposes to classify use of LFG in the Gas 2 category. *See Boiler MACT Reconsideration*, 76 Fed. Reg. at 80,641, 80,652, 80,655. Yet, as EPA offers no sound science or policy rationale supporting its proposed listing of LFG as a Gas 2 fuel, AIF urges EPA to automatically identify LFG in the Gas 1 fuel category in the final reconsideration rule.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Shannon S. Broome
Commenter Affiliation: Auto Industry Forum (AIF)
Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1
Comment Excerpt Number: 16

Comment: As noted above, [See DCN EPA-HQ-OAR-2002-0058-3512-A1.] July 15, 2011, comments concluded that LFG is comparable to the Gas 1 fuels NG and RG in the relevant emission measures. In the [See DCN EPA-HQ-OAR-2002-0058-3512-A1.], dated December 2011, CH2M Hill provides further support as to its relative equivalence. *See* [See DCN EPA-HQ-OAR-2002-0058-3512-A1.] (December 2011), (attached to these comments). CH2M Hill conducted a comparison of the emission properties of boilers firing LFG as fuel to those of boilers firing Gas 1 fuels NG and RG, and examined the readily available public information to compare those fuels. As reflected in the report, CH2MHill concludes that sufficient data were readily available for EPA to establish that LFG is comparable to NG and RG with regard to HAP emissions, and that both emissions and raw gas analysis data support classification of LFG as a Gas 1 fuel. Accordingly, EPA cannot reasonably treat LFG differently from the Gas 1 fuels NG and RG. It should identify LFG as a Gas 1 fuel in the final reconsideration rule.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Shannon S. Broome
Commenter Affiliation: Auto Industry Forum (AIF)
Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1
Comment Excerpt Number: 17

Comment: *As Extensive Data Reflect Hg Concentrations in Landfill Gas as Consistently and Considerably Below the 40 µg/m³ Limit in the “Other Gas 1 Fuel” Specification, EPA Should Automatically Classify Landfill Gas as a Gas 1 Fuel.* As discussed in greater detail below, EPA proposes to eliminate the H₂S fuel specification and use a fuel specification for “other Gas 1 fuel” based only on the Hg level in the gaseous fuel (using the same level as EPA included in the final rule). *See Boiler MACT Reconsideration Proposal*, 76 Fed. Reg. at 80,653. EPA proposes a new definition of “other Gas 1 fuel” in 40 C.F.R. § 63.7575 as: a gaseous fuel that is not natural gas or refinery gas and does not exceed the maximum concentration of 40 micrograms/cubic meters of mercury.

Id. Under this proposal, LFG – as well as other gaseous fuels besides NG and RG – still would still initially fall under a Gas 2 fuel classification but could now gain classification in the “other Gas 1 fuel” category with a demonstration of not exceeding the previously published Hg limit of 40 µg/m³.

The large quantity of available data, including data developed by EPA in 2008, demonstrates that LFG consistently tests for concentrations of Hg well below the 40 µg/m³ threshold.⁸ The Hg concentrations reported in the numerous studies listed in Attachment D (attached to these comments) provide sufficient evidence, in accordance with § 63.7521(i), and without the need to conduct further studies, to identify LFG as a Gas 1 fuel along with NG and RG. As is articulated in Attachment D, based on the individual data measurements reported in the numerous published

studies, the mean concentration of Hg in LFG is 2 µg/m³ and the 95% upper confidence limit is 2.7 µg/m³—*i.e.*, well below the 40 µg/m³ threshold.⁹

The abundant published data on Hg levels in LFG, including the many studies sponsored by EPA, support an automatic Gas 1 categorization for LFG as a Gas 1 fuel. The data demonstrate that Hg concentrations in LFG are consistently below the 40 µg/m³ fuel specification level. There are far more data on the record demonstrating LFG as containing concentrations of Hg well below the 40 µg/m³ threshold than data demonstrating, for example, concentrations of RG as falling below that threshold. EPA’s determination to automatically classify RG as a Gas 1 fuel based on that dataset indicates that LFG should be treated similarly given the dataset on its emissions levels.¹⁰ There is no rational basis to subject units that utilize LFG to the certification and monthly testing provisions of the demonstration mechanism (discussed in more detail in the succeeding sections).

[Footnote 8: This data is outlined in greater detail in the attached document entitled “Studies of Mercury Concentrations in Landfill Gas,” Attachment D (attached to these comments).]

[Footnote 9: The overall mean concentration of Hg in LFG and the highest 95% upper confidence limit, calculated from one study that presents only summary statistics as opposed to individual test results, is 4 µg/m³ and 12 µg/m³, respectively.]

[Footnote 10: The AIF agrees that RG should be treated as Gas 1. EPA should treat similar fuels similarly and cannot justify imposing a higher testing or “proof” standard to LFG.]

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Shannon S. Broome

Commenter Affiliation: Auto Industry Forum (AIF)

Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1

Comment Excerpt Number: 18

Comment: *Compelling Policy Reasons Support EPA Automatically Classifying Landfill Gas as a Gas 1 Fuel.*

LFG functions as a viable replacement for fossil fuel and AIF’s members have chosen to purchase LFG and utilize it as an alternate fuel to NG, in part *in response to EPA programs* encouraging its use in this manner. For some members, this can function as a key element in their corporate sustainability goals. The imposition of new and unreasonable regulatory burdens on LFG combustion would undercut LFG’s viability as a renewable alternative fuel and the investment made in its use by many companies, including AIF’s members. EPA’s failure to identify LFG as a Gas 1 fuel would subject units utilizing LFG to stringent emission limits, which many facilities, including those owned and/or operated by AIF members, would struggle to meet, thereby creating strong disincentives to the use of LFG in boilers.¹¹ Such an outcome would conflict with EPA’s stated policy of encouraging the beneficial use of LFG. *See LMOP, supra.* Under the Boiler MACT, units designed to burn Gas 2 fuels are subject to strict numeric emission limits for certain HAPs. By EPA’s own analysis, the estimated control costs for Gas 2 units are higher than the combined compliance capital costs for boilers and process heaters in all

other categories. *See* LMOP, *supra*. Many of the facilities owned and/or operated by AIF members would be forced to consider using only NG or some other fossil fuels if LFG-firing in boilers is subjected to Gas 2 emission limits.

Discouraging the use of LFG as an alternate to NG could lead to detrimental environmental impacts. As of September 20, 2011, EPA's LMOP contained data on 60 boiler projects and 17 boiler-steam turbine projects that utilize LFG. EPA estimates reflect the 60 boiler projects as utilizing approximately 1900 Million British Thermal Units per hour ("MMBtu/hr") of LFG and the 17 boiler-steam turbine projects as utilizing approximately 2400 MMBtu/hr of LFG.¹² If those project owners and/or operators were to stop combusting LFG and instead combust NG, the landfills could not simply cease producing the LFG those projects use; rather, the landfills would have to combust the neglected LFG, increasing emissions of greenhouse gases and criteria pollutants. Based on EPA's own calculations, the resulting net increase in overall fossil fuel-based CO₂ emissions from those boiler and boiler-turbine projects would be 2,025,698 tons. Further, the nation would experience additional emissions of 12,841 tons of CO, 291 tons of PM and 684 tons of NO_x, as well as slight increases in SO₂ and Hg emissions.

Unless EPA amends the reconsideration proposal, the regulated community, including AIF's members, would likewise incur significant financial costs combusting NG rather than LFG to comply with the Boiler MACT. For boiler and boiler-turbine projects now using LFG, the order-of-magnitude estimate of the total direct costs of switching to NG is \$ 1.064 billion. *See* CH2M Hill, *Boiler MACT Economic Impact Evaluation* (Nov. 9, 2011), Attachment B (attached to these comments). Moreover, project owners would lose the value of the LFG processing and transport equipment that they would have to abandon in ceasing to use LFG. *See id.* The total estimated capital assets lost for existing projects would be \$87 million. *See id.*

These compelling policy reasons indicate that EPA should automatically identify LFG as a Gas 1 fuel in the final reconsideration rule.

[Footnote 11: AIF members with units presently utilizing LFG anticipate they would not be able to meet the Gas 2 category's stringent emission limits (*e.g.*, for CO), particularly in the case of units designed and permitted to minimize emissions of NO_x (for ozone attainment).]

[Footnote 12: *See EPA Landfill Methane Outreach Program (LMOP) Environmental Analysis* (provided to Waste Management), Attachment A (attached to these comments).]

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Richard Krock

Commenter Affiliation: The Vinyl Institute

Document Control Number: EPA-HQ-OAR-2002-0058-3526-A1

Comment Excerpt Number: 10

Comment: EPA's revisions, however, do not go far enough. The fuel gas specification should be amended to remove mercury when the gas in question is hydrogen. Hydrogen is a very clean fuel and as a consequence few labs are experienced in analyzing and testing hydrogen gas, nor are they equipped to do so because of its explosible nature. To the VI's knowledge, there is only

one mercury cell chlorine plant left in the U.S. that generates hydrogen gas that might be used in boilers or process heaters. Many other plants produce hydrogen byproducts that could be burned in boilers or process heaters, but have no contact with mercury in their processes. EPA should amend the fuel specification to allow hydrogen gas to qualify as a Gas 1 fuel without mercury testing where the facility's processes could not contaminate the hydrogen gas with mercury.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 9

Comment: In its Petition for Reconsideration, CIBO stated that landfill gas should be categorized as a Gas 1 gaseous fuel. In its Proposed Reconsidered rule, however, EPA has excluded landfill gas from the Gas 1" category. 76 Fed. Reg. 80,655. Units that combust landfill gas should be treated as Gas 1 units because landfill gas emissions are comparable to emissions from Gas 1 gases – natural gas and refinery gas – and therefore there is no rational basis to treat landfill gases differently, as noted in CIBO's Petition for Reconsideration.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 11

Comment: In applying these fuel specifications to landfill gas, data show that landfill gas consistently contains less Hg than the permitted 40 mm/m³. Therefore, landfill gas should be given a categorical exemption from the certification and testing requirements of the fuel specification mechanism.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Edward W. Repa

Commenter Affiliation: National Solid Wastes Management Association (NSWMA)

Document Control Number: EPA-HQ-OAR-2002-0058-3539-A1

Comment Excerpt Number: 4

Comment: NSWMA recommends that LFG be classified as a Gas1 fuel in the proposed reconsideration rule based on the above data for H₂S and Hg. If a boiler user switches from LFG to either RG or NG to avoid the overly stringent proposed regulations of LFG, criteria pollutants and greenhouse gases will increase. This fuel switching does not benefit other EPA programs or the environment.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Edward W. Repa

Commenter Affiliation: National Solid Wastes Management Association (NSWMA)

Document Control Number: EPA-HQ-OAR-2002-0058-3539-A1

Comment Excerpt Number: 5

Comment: Under proposed Section 63.730(g), other gaseous fuels must meet the Hg standard during an initial test and if the fuel varies above the initial test additional Hg testing must be performed monthly. This section also requires that the other gas fuel not exceed the standard and requires a "Notification of Compliance Status." Based on the data in Table 2, these requirements should not apply to LFG. [see submittal Table 2] Furthermore, applying monthly testing of LFG is onerous, costly, and not supported by the data.

Again, NSWMA recommends that LFG be classified as a Gas 1 fuel. However, before EPA imposes these requirements on LFG, EPA needs to justify such action. We also recommend that EPA revise the language in the section such that a designated representative can actually sign the notification without undo legal or fiduciary risk.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Edward W. Repa

Commenter Affiliation: National Solid Wastes Management Association (NSWMA)

Document Control Number: EPA-HQ-OAR-2002-0058-3539-A1

Comment Excerpt Number: 8

Comment: The proposed rule does not subject RG and NG, both designated Gas 1 fuels, to the same standards as LFG. NSWMA's Landfill Institute again recommends that EPA classify LFG as a Gas 1 fuel.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Angela D. Marconi

Commenter Affiliation: Delaware Solid Waste Authority (DSWA)

Document Control Number: EPA-HQ-OAR-2002-0058-3545-A2

Comment Excerpt Number: 1

Comment: LFG should be classified as a "gas I" in the final rule publication. As presently written, only natural gas (NG) and refinery gas (RG) qualify as 'gas I' fuels. As such, boilers using NG or RG and subject to work practice standards rather than emission standards. RG is defined in the Boiler MACT as follows:

Refinery gas means any gas that is generated at a petroleum refinery and is combusted. Refinery gas includes natural gas when the natural gas is combined and combusted in any proportion with

a gas generated at a refinery. Refinery gas includes gases generated from other facilities when that gas is combined and combusted in any proportion with gas generated at a refinery.

In "Refinery Gas Category Analysis and Hazard Characterization" the American Petroleum Institute (API) discusses the production and variability of RG. Stating that RG:

are primarily produced in petroleum refineries as the light end fractions of numerous distillation and cracking processes, or in gas plants that separate natural gas and natural gas liquids. These gases exist as substances in closed systems in the refinery, with none being sold as finished products because one or more constituents of refinery gases make them unsuitable for commercial sale (pg4).

RG is typically used to generate power in the refinery. When this is not possible the gases are flared to control emissions.

Similarly, LFG must be flared when it cannot be beneficially used. It is essential to consider that if onerous regulations preclude the beneficial use of LFG, no emission reductions will be gained because the LFG will be controlled by flaring. In fact, the use of fossil fuels in place of LFG (while flaring LFG) will increase emissions, therefore LFG use is preferable.

Although LFG is capable of qualifying as an "other gas 1" by either certifying the quality or subjecting to monthly testing, categorizing LFG as either "gas 2" or "other gas 1" puts an undue burden on landfills and the industries that utilize LFG. Imposing these additional requirements has the potential to severely hinder the beneficial use of LFG because many LFGTE projects are only marginally economically viable. The reconsideration should not limit the utilization of LFG or otherwise discourage its beneficial use. The most direct way of ensuring this is to extend the definition of "gas 1" to include LFG.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Kerry Kelly

Commenter Affiliation: Waste Management (WM)

Document Control Number: EPA-HQ-OAR-2002-0058-3681-A2

Comment Excerpt Number: 1

Comment: From an environmental and economic perspective, the combustion of LFG in boilers is a positive alternative to control of LFG in flares. Failure to categorize LFG as a "Gas 1" fuel will subject LFG boilers to stringent emission limits, thereby creating strong disincentives to the use of LFG in boilers and hampering many private, local government and federal government facilities' sustainability efforts and significantly disrupting domestic renewable energy production. The U.S LFG to energy sector is a significant portion of the domestic renewable energy sector, producing more than 7 times the energy output of the entire domestic solar energy sector².

[Footnote]

(2) U.S. Energy Information Administration Independent Statistics and Analysis, 2009

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Kerry Kelly

Commenter Affiliation: Waste Management (WM)

Document Control Number: EPA-HQ-OAR-2002-0058-3681-A2

Comment Excerpt Number: 2

Comment: Under the proposed Boiler MACT Reconsideration Rule, units designed to burn Gas 1 fuel (including natural gas and refinery gas) are not subject to emission limits, while units designed to burn “Gas 2” fuels are subject to strict numeric emission limits for PM, HCL, Mercury and CO. By EPA’s own analysis, the control costs for Gas 2 boilers are estimated to be higher than the combined compliance capital costs for boilers and process heaters in all other categories. WM’s LFG customers have indicated that they may not be able to meet the proposed Gas 2 emission limits (e.g., for CO) particularly for units designed and permitted to minimize NOx emissions (for ozone attainment). Therefore, the boiler owners may be forced to switch to natural gas if LFGfired boilers are subject to “Gas 2” emission limits. EPA’s creation of such disincentive for use of LFG is contrary to the Agency’s own stated policy of encouraging the beneficial use of LFG³. The environmental consequences of creating barriers to using LFG are very detrimental. As of September 20, 2011, EPA’s LMOP has data on 60 U.S. boiler projects and 17 projects that utilize LFG in boiler-steam turbines. EPA estimates that the 60 boiler projects utilize approximately 1900 Million British Thermal Units (MMBtu) per hour of LFG, and that the 17 boiler-steam turbine projects utilize approximately 2400 MMBtu per hour of LFG. If the project owners switch from LFG to natural gas, LFG will still be generated by the landfills and therefore must be combusted, increasing emissions of greenhouse gases and criteria pollutants. EPA calculated the net increase in overall fossil fuel based CO2 emissions from boiler and boiler – turbine projects would be 2,025,698 tons. The nation would also realize an additional 12,841 tons of CO, 291 tons of PM and 684 tons of NOx. SO2 and mercury emissions would also increase slightly by 10.2 and 0.0052 tons, respectively. [See submittal for Attachment A –EPA LMOP Environmental Analysis provided to WM]

[Footnote]

3 USEPA, Landfill Methane Outreach Program, <http://www.epa.gov/lmop/basic-info/index.html>, February 2012

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Kerry Kelly

Commenter Affiliation: Waste Management (WM)

Document Control Number: EPA-HQ-OAR-2002-0058-3681-A2

Comment Excerpt Number: 3

Comment: The financial costs associated with switching from LFG to natural gas to comply with the Boiler MACT Reconsideration Rule as proposed, are also quite significant. For boiler and boiler-turbine projects now using LFG, the order-of-magnitude estimate of the total direct

costs of switching from LFG to natural gas is estimated to be \$ 1.064 billion. In addition, project owners will lose the value of the LFG processing and transport equipment that must be abandoned when fuel switching from LFG. The total estimated capital assets lost for existing projects is \$87 million. [See submittal for Attachment B – CH2M Hill Boiler MACT Economic Impact Evaluation]

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Kerry Kelly

Commenter Affiliation: Waste Management (WM)

Document Control Number: EPA-HQ-OAR-2002-0058-3681-A2

Comment Excerpt Number: 4

Comment: EPA has already evaluated, and regulated, hazardous air pollutant (HAP) emissions that may result from the two circumstances under which LFG may be used in a boiler under the Landfill NSPS and the Landfill MACT. First, LFG fired directly to a boiler operating as a control device is subject to the non-methane organic compounds (NMOC) emission standard that was established pursuant to the Landfill NSPS and determined under the Landfill MACT to adequately address HAP emissions. Imposition of additional emission limits from such control devices would constitute an impermissible duplication of emission limits under Section 112 of the CAA. Second, the Landfill NSPS and the Landfill MACT require that LFG used as a fuel must be treated and processed in a manner that ensures proper combustion in accordance with specifications required by the receiving combustion unit. Imposition of emission limits under the Boiler MACT Reconsideration Rule, as proposed for this use of LFG, where natural gas and refinery gas are not subject to such limits, would create an extreme disincentive to the use of LFG for energy recovery. For these reasons, the Gas 2 emission limits in the Boiler Rule should not apply to LFG-fired boilers. The emission limits established for Gas 2 units are technically infeasible and cost prohibitive to promoting renewable sources of energy. As previously stated, WM’s LFG customers have indicated that they may not be able to meet the Gas 2 emission limits particularly units designed and permitted to minimize NO_x emissions (for ozone attainment). Therefore, they may be forced to switch to natural gas if LFG-fired boilers are subject to “Gas 2” emission limits.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Kerry Kelly

Commenter Affiliation: Waste Management (WM)

Document Control Number: EPA-HQ-OAR-2002-0058-3681-A2

Comment Excerpt Number: 5

Comment: In our Petition for Reconsideration of the Boiler MACT Rule, WM requested that the Agency reconsider its categorization of LFG as “Gas 2” and amend the rule to clarify that LFG constitutes a “Gas 1” fuel for which the imposition of emission limits is infeasible and impracticable. EPA’s proposed Boiler MACT Reconsideration Rule fails to do so. Furthermore,

the proposed Boiler MACT Reconsideration Rule offers no sound science or policy rationale for continuing to list LFG as a Gas 2 fuel.

WM contracted with CH2M Hill to conduct a comparison of the emissions properties of boilers firing LFG as fuel to those of boilers firing Gas 1 fuels, and to examine the publicly available information to compare LFG to Gas 1 fuels, specifically natural gas and refinery gas. [See submittal for Attachment C – Boiler MACT Fuel Classification Review for Landfill Gas] CH2MHill concluded that sufficient data were readily available for EPA to establish that LFG is comparable to natural gas and refinery gas with regard to HAP emissions, and that both emissions and raw gas analysis data support the conclusion that LFG should be classified as a Gas 1 fuel. A brief summary of the report conclusions follows. Table 3 from the CH2M Hill report provides a comparison of the readily available data for total mercury in LFG to comparable data for natural gas and refinery gas. [See for Table 3 of Attachment C]

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Kerry Kelly

Commenter Affiliation: Waste Management (WM)

Document Control Number: EPA-HQ-OAR-2002-0058-3681-A2

Comment Excerpt Number: 6

Comment: EPA’s 2008 effort to establish an appropriate default parameter for Hg in LFG found no instances of LFG exceeding the fuel specification value of 40 micrograms per cubic meter ($\mu\text{g}/\text{m}^3$) among the numerous tests conducted that EPA reviewed. Data developed by EPA in its 2008 BID support the conclusion that the mercury levels in LFG are consistently much lower than the Gas 1 fuel specification level of 40 $\mu\text{g}/\text{m}^3$, which should serve as a basis for listing LFG in the same Gas 1 category as natural gas and refinery gas. The data for mercury in LFG supports its characterization as a Gas 1 fuel. Mercury levels in raw LFG from 15 landfills reported in EPA’s BID (2008) indicated a range of total mercury levels comparable to levels found in the available data for mercury in natural gas. Because of the dearth of available data for HAP and surrogate parameters in the Gas 1 fuels, one cannot effectively compare the constituents of raw LFG to the recognized Gas 1 fuels for those parameters. However, a comparison of the readily available emissions data for boilers fueled by only LFG indicates that the ranges of reported results for mercury, PM, CO, and dioxin/furans are within or below the ranges of those parameters for one or both of the recognized Gas 1 fuels, natural gas and refinery gas. No HCl data were available for refinery gas for comparison to LFG. However, the few HCl emissions data available from LFG-fueled boilers (0.00321 to 0.00398 pounds per million British thermal units [lb/MMBTU]) are lower than the Boiler MACT emission limits for both new and existing solid fuel-fired units (0.022 lb/MMBTU).

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Kerry Kelly

Commenter Affiliation: Waste Management (WM)

Document Control Number: EPA-HQ-OAR-2002-0058-3681-A2

Comment Excerpt Number: 7

Comment: Numerous Published Studies Have Measured Mercury Concentrations in LFG. A large dataset of mercury concentrations in LFG is available from numerous published studies and reports. In the proposed rule, however, it appears the Agency considered only three LFG samples and these were evaluated on a lb/MMBtu basis (Excel Spreadsheet. MACT Floor Memo Appendixes C, D, and E. Boiler Maximum Achievable Control Technology docket site, EPA Docket No. EPA-HQOAR- 2002-0058-1388.1).⁴ Although emission limits are evaluated on a lb/MMBtu basis, the fuel specification limit is based on the mercury concentration in LFG reported in units of micrograms per cubic meter ($\mu\text{g}/\text{m}^3$). The published studies that have included sampling of mercury in LFG are shown in the table below. [See pg 5 of the submittal for the table of studies] Samples have been collected from more than 30 landfills located throughout the United States and the United Kingdom. All of these studies are readily available through the internet and, in fact, several were conducted for EPA. This wealth of information should be considered by the Agency as part of this proposed rule.

[Footnote]

(4) The three mercury measurements, collected from a single landfill gas unit at a BMW facility, were incorrect. EPA indicated in its response to comments that this error has been corrected (See comment and response on May 18, 2011 reconsideration notice in 76 FR 28662 at EPA Docket Control No. EPA-HQ-OAR-2002-0058-2775.1).

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Kerry Kelly

Commenter Affiliation: Waste Management (WM)

Document Control Number: EPA-HQ-OAR-2002-0058-3681-A2

Comment Excerpt Number: 8

Comment: Mercury Concentrations in LFG Are Consistently Below the 40 $\mu\text{g}/\text{m}^3$ Fuel Specification Limit. As noted above, a large dataset of mercury concentrations in LFG is available from numerous published studies and reports, including many studies conducted for EPA (USEPA 2005, 2007, 2008, 2009, 2012; Frontier 2003; Lindberg et al. 2005; Netcen 2003; UKEA 2004). These data have been collected from 30 landfills located throughout the United States and 12 landfills in the United Kingdom. Overall, these studies provide a robust database of more than 150 measurements that reliably characterizes the levels of mercury in LFG. To demonstrate that a gaseous fuel other than natural gas or refinery gas qualifies as a Gas 1 fuel (76 FR 80633), the rule requires that a fuel specification analysis be conducted. The analysis must characterize mercury concentrations in the fuel, demonstrate that mercury concentrations do not exceed 40 $\mu\text{g}/\text{m}^3$, and address a variety of associated requirements related to sampling and analysis (e.g., descriptions of sample locations, procedures for collecting and analyzing samples). The existing database of mercury LFG measurements complies with the objectives of the proposed Boiler MACT Reconsideration Rule regarding a fuel specification analysis. In fact, this database presents a more comprehensive characterization of mercury in LFG than would be

developed for any individual fuel source. The sample size of the existing dataset is substantially greater than the number of samples that would be collected under the proposed rule. Indeed, the proposed rule appears to indicate that collection of three samples from each fuel type would be adequate for a fuel specification analysis and Section §63.7521(h) implies that even one sample may be adequate. In addition, each of the published LFG studies provides descriptions of sample locations, sample collection and analysis methods, and assessments of data quality. These elements address the fuel specification requirements laid out in §63.7521(g)(2). The mercury concentrations reported in the existing database provide sufficient evidence, in accordance with §63.7521(i) and without the need to conduct further studies, to qualify LFG as a Gas 1 fuel. These data consistently demonstrate that concentrations are below the 40 µg/m³ fuel specification limit. All of the measurements reported in the published literature are below 40 µg/m³. Additionally, the mean concentration of mercury in LFG is 2 µg/m³ and the 95% upper confidence limit is 2.7 µg/m³, based on the individual data measurements reported in the many published studies noted above. The overall mean concentration of mercury in LFG and the highest 95% upper confidence limit, calculated from one study which presents only summary statistics and not individual test results, is 4 µg/m³ and 12 µg/m³, respectively. In sum, the Agency should consider the abundant published data on mercury levels in LFG in this rulemaking, including the many studies that it has sponsored. These data demonstrate that mercury concentrations in LFG have been proven to be consistently below the 40 µg/m³ fuel specification limit and support the characterization of LFG as a Gas 1 fuel. Based on the above analysis, WM strongly recommends that LFG be categorized as Gas 1 under the Boiler MACT Reconsideration Rule. The data for mercury and hydrogen sulfide (H₂S) in LFG support its characterization as a Gas 1 fuel.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Dan F. Hunter

Commenter Affiliation: ConocoPhillips Company

Document Control Number: EPA-HQ-OAR-2002-0058-3689-A2

Comment Excerpt Number: 2

Comment: Although ConocoPhillips believes the fuel used for boilers and process heaters (BPH) at many oil and natural gas facilities will fall into the definition of natural gas, we are concerned that some natural gas plants use a gas stream containing higher concentrations of ethane, propane, and butane, and may not meet the definition of natural gas because the gas contains less than 70% methane or does not fit into the heating value range of 910 to 1,150 Btu/SCF. We request for EPA to classify fuel gas at natural gas plants not meeting the definition of a natural gas, to be classified as "other gas 1" and not be required to verify mercury content. This change would make the process gas at natural gas plants more consistent with refinery fuel gas which is defined separately.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Elizabeth McMeekin
Commenter Affiliation: PPG Industries, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-3778-A1
Comment Excerpt Number: 5

Comment: PPG, like many integrated chemical plants, uses process gases from processing areas as fuels in boilers and process heaters. PPG's process gas is a clean-burning hydrogen. The use of this hydrogen is critical to maintaining energy efficiency and cost efficiencies at our sites. Based on the extremely low numeric standards proposed for Gas 2 units and the uncertainty surrounding the efficacy of expensive add-on controls, PPG would likely be forced to burn these process gases in a non-optimal manner, such as routing this fuel to flares or other combustion sources at the site, and replacing the lost fuel value by burning more natural gas. Forcing this switch is contrary to the nation's goal of reducing fossil fuel use and encouraging use of alternate energy sources.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

107A03. Re-Evaluate Gas 2 Subcategory [DENIED PETITIONER ISSUE]

Commenter Name: Peter Pagano
Commenter Affiliation: American Iron and Steel Institute (AISI)
Document Control Number: EPA-HQ-OAR-2002-0058-3490-A1
Comment Excerpt Number: 30

Comment: The MACT floor for Gas 2 units is based on insufficient data.

EPA's reconsidered rule magnifies an error that AISI identified in its comments on the previous Boiler MACT proposed rule submitted on August 23, 2010. EPA improperly relies on a single source to set the Gas 2 MACT Floor emission rates. In the reconsidered rule, EPA now relies on a single source for *all* of the Gas 2 emission limits. We understand and support EPA's decision to reduce the size of the Gas 2 subcategory in the reconsidered proposed rule. However, Congress directed EPA to use a group of sources to set existing source MACT standards as distinct from the best single source, which Congress reserved for the new source MACT standard. Cf. §§ 112(d)(3)(A) and (B). EPA must recalculate the Gas 2 MACT Floors to reflect more than one source for a subcategory that now contains 129 sources by EPA's count.

In fact, Congress preferred that EPA use a minimum of five sources when setting the MACT Floor emission limits for a source category. The word "sources" as used in the last clause of §§112(d)(3)(A) and (B) to describe the size of the subcategory at issue does not specify whether it refers to "sources" for which data exist or the total number of sources in the subcategory. However, the word "sources" in the earlier facets of those sections clearly refers to the sources for which EPA has emissions information. Thus, it is reasonable to conclude that Congress intended the word "sources" to have a consistent meaning within these subsections and that the reference "30 or more sources" at the end of § 112(d)(3)(A) and "fewer than 30 sources" at the end of § 112(d)(3)(B) reasonably means sources for which EPA has emissions information. That interpretation allows EPA to read the statute such that Congress' chosen line between new and

existing source-setting methodology is not blurred. Alternately, EPA's use of at least 5 sources could also be justified under the "absurd results" doctrine. Congress clearly expected enough emissions information to be available for larger source categories to generally cause more than 5 sources to constitute the top 12%. It makes no sense for Congress to specify a minimum number of sources for source categories with few sources, but then to create a rule that would allow for standards to be set using data from fewer than 5 sources in larger source categories. Using no less than 5 sources would give effect to the clear intention of Congress.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Peter Pagano

Commenter Affiliation: American Iron and Steel Institute (AISI)

Document Control Number: EPA-HQ-OAR-2002-0058-3490-A1

Comment Excerpt Number: 31

Comment: A single source used to establish the MACT Floor raises a number of additional concerns. First, the single source cannot adequately represent the variability across sources within a subcategory based on design, age, load, or location. Second, a single source MACT Floor offers no check on irregularities or anomalies in the stack test sampling or laboratory analysis for the data that EPA is using to set the standard. If multiple sources are used to set the MACT Floor, clear outliers or data errors can be better assessed and are mitigated by the averaging across different sources using different stack testing companies and laboratories. Finally, the single source may prove to be in an entirely different subcategory. The single source used for Gas 2 MACT Floors is a coke plant in Follansbee West Virginia that burns coke oven gas or a mixture³⁹ containing coke oven gas in its affected boiler. In its November 2011 MACT Floor Memo, at page 4, EPA states, "We did not assume that coke oven gas would be able to meet the fuel specification that is in the proposed rule, although some coke oven gas may meet the specification." If the Follansbee boiler burns coke oven gas that meets the Gas 1 specification, the entire Gas 2 MACT Floor analysis is without basis. EPA should revisit the quality and quantity of data that it relied on in setting the MACT Floor for the Gas 2 subcategory.

[Footnote]

(39) EPA's gas 2 subcategory includes affected gas-fired units (not otherwise exempt) that burn any amount of a Gas 2 fuel. *See* 76 FR 80655 (Dec 23, 2011) (defining "*unit designed to burn gas 2 (other) subcategory*"). It follows that the MACT Floor for the Gas 2 subcategory could be based on test data from units burning primarily natural gas or other gas 1 fuel. EPA should identify the mixed gas ratio for the unit establishing the gas 2 MACT Floor so we can assess its relevance to the gas 2 subcategory.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Bruce A. Steiner

Commenter Affiliation: American Coke and Coal Chemical Institute (ACCCI)

Document Control Number: EPA-HQ-OAR-2002-0058-3547-A2

Comment Excerpt Number: 8

Comment: If EPA Decides That Gas 2 Numerical Emission Limits Apply to Coke Oven Gas-Fired Units, a Separate Subcategory for Coke Oven Gas-Fired Units Should Be Considered EPA has proposed the Gas 2 subcategory to encompass all gaseous fuels that are not natural gas or refinery gas. This catch-all subcategory includes landfill gas, coke oven gas, coal-derived gas, biogas, and other process gases. EPA offers no justification for combining these disparate gases into a single subcategory but it may have been driven by a lack of data. With just five sources in the Gas 2 subcategory with dioxin-furan data and just eight sources with data for Hg and HCl, EPA had tied its own hands by not collecting sufficient data to properly distinguish between fuels with significantly different chemical compositions, heating values, and combustion characteristics. EPA's decision to lump these Gas-2 sources together based on what they are not (e.g., because they are not burning natural or refinery gas) is arbitrary and unlawful. Gas 2 fuels are not interchangeable. These gaseous fuels are combusted at or near their point of generation and used to reduce reliance on fossil fuels. Therefore, a Gas 2 source cannot decide to burn landfill gas to help meet the Hg emission standards if they are not in the vicinity of a landfill. Similarly, coke oven gas is only available in the vicinity of coke batteries. Thus, most of the 199 Gas 2 sources cannot use coke oven gas to help other Gas 2 emission limits. Nor does it make environmental or economic sense to displace process gases with natural gas, because flammable process gases must be combusted to meet health and safety requirements. Flaring process gases and burning natural gas to reduce emissions at the boiler increases facility-wide emissions, decreases energy independence, and wastes opportunities for energy efficiency. Process gas-fired sources are not candidates for fuel switching. EPA must, as a result, evaluate and understand the emission characteristics of each process gas fuel to determine if its Gas 2 subcategory is properly defined as a reasonable aggregation of similar sources. EPA has proposed an arbitrary aggregation of dissimilar fuels in the Gas 2 subcategory, which would result in emission limits that are not achievable when burning some process gases even when implementing all available control measures. This should be a strong signal that further subcategorization is warranted prior to the promulgation of the final Boiler MACT rule. If EPA will be setting numeric emission limits for coke oven gas-fired boilers, then these units need a separate subcategory because they have no pathway to attain emission limits established by dissimilar landfill gas and biogas-fired units.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Bruce A. Steiner

Commenter Affiliation: American Coke and Coal Chemical Institute (ACCCI)

Document Control Number: EPA-HQ-OAR-2002-0058-3547-A2

Comment Excerpt Number: 10

Comment: To gain a better understanding of the potential risk faced by coke oven gas-fired units under the broad Gas 2 subcategory proposed by EPA, an ACCCI member company conducted stack tests on four coke oven gas-fired boilers in July 2010. These test results were reported in our August 23, 2010 comments on the originally proposed rule and will not be repeated in detail here. Suffice it to state that the test results confirm that the proposed Gas 2

emission limits for HCl, Hg, and CO are not achievable for these coke oven gas-fired boilers using commercially available emission control technologies. The levels of HCl, Hg, and CO exceed the proposed Gas 2 limits by such a large margin that available emission control measures would be insufficient to achieve the proposed Gas 2 limits. Even if optimistic assumptions for control efficiency are applied to the uncontrolled levels measured in these tests, it is clear that the Gas 2 emission limits cannot be reliably achieved. Based on this analysis, it is technically infeasible for coke oven gas-fired boilers to achieve the proposed Gas 2 emission limits. Therefore, in the event that numerical emission limits are imposed on coke oven gas-fired units over our prior noted objections, we recommend that EPA consider developing a separate subcategory for coke oven gas-fired units to accommodate their unique chemical composition and emission profile.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

107A04. Metal Process Furnace Definition [DENIED PETITIONER ISSUE]

Commenter Name: William C. Herz

Commenter Affiliation: The Fertilizer Institute (TFI)

Document Control Number: EPA-HQ-OAR-2002-0058-3448-A1

Comment Excerpt Number: 1

Comment: When EPA proposed the *Industrial Boiler Major Source NESHAP* (75 Fed. Reg. 32006 (June 4, 2010)), the Agency recognized that the designation of subcategories for boilers and process heaters should be based on the "primary fuel" that the boiler or process heater is designed to burn.² To that end, the Agency recognized when defining a number of the subcategories that a boiler or process heater may burn fuels other than the primary fuel, so long as the other-than-primary fuels are burned at no more than 10 percent of the heat input to the unit. Several examples are cited below: *Blast furnace gas fuel-fired boiler or process heater* means an industrial/commercial/institutional boiler or process heater that receives 90 percent or more of its total heat input (based on an annual average) from blast furnace gas.

Liquid fuel subcategory includes any boiler or process heater of any design that burns more than 10 percent liquid fuel and less than 10 percent solid fuel, on an annual heat input basis.

- and relevant to TFI members -

Units designed to burn gas 1 (NG/RG) subcategory includes any boiler or process heater that burns at least 90 percent natural gas and/or refinery gas on a heat input basis on an annual average.³

In the final *Industrial Boiler Major Source NESHAP* and the Proposed Rule, EPA retains the flexibility for units to remain within a subcategory while also burning other fuels, so long as the other-than-primary fuels are burned at no more than 10 percent of the heat input to the unit.

As examples:

Blast furnace gas fuel-fired boiler or process heater means an industrial/commercial/institutional boiler or process heater that receives 90 percent or more of its total annual gas volume from blast furnace gas.

Liquid fuel subcategory includes any boiler or process heater of any design that burns more than 10 percent liquid fuel and less than 10 percent solid fuel, based on an total annual heat input to the unit.

However, relevant to TFI members, in the final *Industrial Boiler Major Source NESHAP* and the Proposed Rule, EPA deletes the no more than 10 percent other-than-primary fuels flexibility for units to remain within the "Unit designed to burn gas 1 subcategory":

Unit designed to burn gas 1 subcategory includes any boiler or process heater that burns only natural gas, refinery gas, and/or other gas 1 fuels; with the exception of liquid fuels burned for periodic testing not to exceed a combined total of 48 hours during any calendar year, or during periods of gas curtailment and gas supply emergencies.

Notably, in neither the preamble to the final *Industrial Boiler Major Source NESHAP* nor the preamble to the Proposed Rule discussing changes to the definitions section of the rule does EPA discuss why it removed the flexibility for gas 1 subcategory units to burn no more than 10 percent of fuels other than natural gas or refinery gas and still remain in this subcategory. [Footnote 2: 75 Fed. Reg. at 32017.]

[Footnote 3: 75 Fed. Reg. at 32063 – 32065 (proposed for codification at 40 C.F.R. § 63.7575) (emphasis added).]

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Peter Pagano

Commenter Affiliation: American Iron and Steel Institute (AISI)

Document Control Number: EPA-HQ-OAR-2002-0058-3490-A1

Comment Excerpt Number: 11

Comment: The definition of metal process furnaces and EPA's metal process furnace subcategory needs to be more inclusive to apply to the iron and steel industry and other process gas industries.

AISI previously provided comments to EPA regarding the impractical scope of its Metal Process Furnace Subcategory as proposed in the June 4, 2010, proposed rule. AISI does not believe the scope of the subcategory adequately addresses EPA's intent. To more accurately capture EPA's intention of developing the Metal Process Furnace Subcategory as it would apply to the iron and steel industry, EPA should include furnaces that combust process gases that would otherwise be flared. The steel industry employs numerous metal process furnaces, including reheat furnaces, annealing furnaces, and heat treating operations. Some of these are direct-fired and are not covered by the rule, but others are indirect-fired units, which would cause them to be classified as process heaters. AISI supports the separate classification of "metal process furnaces," which EPA found to be a "class of natural gas-fired process heaters that are designed and operated

differently compared to typical process heaters."²¹ As explained in the EPA's prior proposed rule from June 4, 2010:

A review of information gathered on process heaters used in the metal processing industries shows that these process heaters typically are designed with multiple burners that fire into individual combustion chambers. These individual burners are operated to cycle on and off to maintain the proper temperatures throughout the various zones of the process heater. Thus, due to their design, these process heaters rarely operate in a steady-state condition due to burners constantly starting up and shutting down. This results in emissions characteristics different from the process heaters used in other industries.²²

That passage correctly identifies the technological and operational issues that justify creation of a metal process heaters subcategory. However, the current proposed rule circumscribes that rationale by defining the subcategory to include only units that combust natural gas. While many metal process furnaces do use natural gas, others beneficially combust process gas, such as coke oven gas, to reduce the amount of additional natural gas needed to operate these units. Combusting process gases in metal process furnaces lowers emissions and increases energy efficiency by supplementing natural gas with a gas that would otherwise be flared.

[Footnotes]

(21) 75 Fed. Reg. 32005,32071 (June 4, 2010).

(22) 75 Fed. Reg. 32005,32071 (June 4, 2010).

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Peter Pagano

Commenter Affiliation: American Iron and Steel Institute (AISI)

Document Control Number: EPA-HQ-OAR-2002-0058-3490-A1

Comment Excerpt Number: 12

Comment: The type of gas combusted in a given metal process heater has nothing to do with the technical and operational distinctions that render them unique, including the distinctions that they are designed with multiple burners in a single unit and rarely operate in a steady-state condition. Rather, those same findings apply equally to all metal process heaters combusting any gaseous fuel. As such, there is no legitimate basis for limiting this subcategory to natural gas-fired units and EPA should redefine this subcategory to include furnaces combusting any gaseous fuel. Such a redefinition would also be in agreement with EPA's goals of reducing emissions and increasing energy efficiency.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Peter Pagano

Commenter Affiliation: American Iron and Steel Institute (AISI)

Document Control Number: EPA-HQ-OAR-2002-0058-3490-A1

Comment Excerpt Number: 14

Comment: In addition, AISI requests that EPA revise the definition of metal process furnace to include the phrase "includes, but is not limited to" to acknowledge the fact that there may be other furnaces that should be excluded for the same reasons that the specifically mentioned examples are exempt. Specifically, in addition to annealing, preheat, reheat, aging, heat treat, and homogenizing furnaces, the following furnaces should be exempt:

Stress relief furnaces, which are similar to aging and heat treat furnaces in that they are used to heat and cool metal to eliminate stresses from forging and similar activities.

Galvanizing/galvanneal furnaces, which are similar to annealing furnaces in purpose and operation, but operate on a continuous (strip) rather than batch (coil) basis. Like annealing furnaces, these units fire sporadically as necessary to achieve an annealed consistency in the metal.

Alternatively, we request that EPA specifically add both of these units to the list of "metal process furnace" examples included in proposed §63.7575 and amend the definition as follows:

Metal Process furnaces include natural gas-fired annealing furnaces, preheat furnaces, reheat furnaces, aging furnaces, heat treat furnaces, and homogenizing furnaces, stress relief furnaces, and galvanizing/galvanneal furnaces.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

107B. Designed to Burn Subcategorization [DENIED PETITIONER ISSUE]

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 1

Comment: In its new proposal, EPA expands the number of subcategories to thirty-eight, nineteen subcategories for both new and existing sources. All of EPA's subcategories are unlawful and arbitrary for the reasons given in the comments of Clean Air Task Force, Earthjustice, Natural Resources Defense Council and Sierra Club ("2010 Comments"), which are attached hereto and incorporated by reference as if fully stated herein and reiterated with respect to the agency's 2011 final rule and the most recently created subcategories in its reconsideration proposal as well as the subcategories EPA initially proposed in 2010. *See* 2010 Comments at 6-8. In particular, units are not of a different "class, type, or size" merely because they are allegedly "designed to burn" a type of fuel when: (1) they are otherwise the same as or closely similar to units that are allegedly "designed to burn" another type of fuel; (2) these units do in fact burn more than one type of fuel; and (3) these units may actually burn a majority of fuel that is not the type they are allegedly "designed to burn." For example, it is unlawful and arbitrary to set different standards for units allegedly "designed to burn" biomass but capable of burning (or actually burning) just 11% biomass and 89% coal on the one hand and for similarly designed

units allegedly “designed to burn” coal and but capable of burning (or actually burning) 9% biomass and 91% coal on the other. Indeed, EPA freely admits that sources can “switch categories” based on the fuel they choose to burn at any given time. Revised MACT Floor Analysis (2011) at 6. Because such units are not of a different “class, type, or size,” EPA lacks authority to set separate emission standards for them and any claim that they are of a different class, type or size is arbitrary.

The unlawfulness and arbitrariness of EPA’s subcategories is exacerbated by the agency’s approach to establishing the statutory minimum stringencies (“floors”) for its standards. To generate its existing-source floors, the Agency restricted its analysis to units burning 90% of the specified fuel. *Id.* New source floors are based on units burning 100% of the specified fuel. *Id.* As a result, the standards which apply to one set of sources (e.g., units burning no more than 10% biomass and more than 10% coal) are generated from the actual emissions of an entirely different group of sources (those burning 90% or 100% coal). That divergence violates the Act, which requires MACT standards to be at least as stringent as the best performing source or sources for the specified category. 42 U.S.C. § 7412(d). Assuming *arguendo* that EPA’s subcategories are valid and can be maintained, the agency’s standards for each one must reflect the emission level achieved by the relevant best performing sources in that specific subcategory. Because EPA has chosen to base floors not on the best performers in its chosen subcategories but instead on a group within the category that is using a certain type of fuel or mix of fuels, EPA’s standards contravene that requirement.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial. In particular, EPA disagrees that EPA’s rationale for subcategorizing boilers based on unit design is inconsistent with the Clean Air Act. The commenter first claims that units designed to burn different fuels are in fact “the same as or closely similar to” each other. As explained in the preamble to today’s action, that is not the case. Different provisions for fuel handling and preparation, fuel combustion, heat recovery, among other things, are needed when burning different fuels. In addition, boiler systems can encounter operational problems if operated on a different fuel than specified for that boiler design. The commenter provides no specific characteristics that to support its assertion that boilers burning different fuels are in fact the same. Further, section 112(d) provides EPA with broad discretion to subcategorize based on class, size, or type. For example, differences between given types of units can lead to corresponding differences in the nature of emissions and the technical feasibility of applying emission control techniques. . It is certainly possible that boilers can have some similar characteristics, but still be of sufficiently different classes, sizes, or types to warrant placing them in different subcategories.

The commenter also states that boilers may burn more than one type of fuel or a mixture of fuels. The commenter claims that it is “unlawful and arbitrary” to create different subcategories for units that are capable of burning more than one fuel or a mixture of fuels because such units are not of different classes, sizes, or types. EPA disagrees with the commenter. Given the broad statutory discretion to create subcategories, and the fact that some boilers do burn different fuels or a mixture of fuels at certain times, it is reasonable for EPA to establish criteria to distinguish among the different types of boilers, including boilers that combust different or a mixture of fuels at certain times. The definition of “Unit designed to burn ...” in the final rule is based on the actual annual heat input of the specific fuel type. Thus, we disagree with the comment that

“EPA freely admits that sources can switch categories ... at any given time. In the final rule, a source compliance demonstration depends on the subcategory it was in based on the fuels it burned the previous 12 months. We also disagree with the commenter assertion that it is arbitrary to set different standards for units designed to burn biomass but capable of burning just 11% biomass and 89% coal. First, as stated previously in the preamble, boiler systems are designed for specific fuel types and will frequently encounter combustion, slagging, fouling, or ash handling problems if a fuel with characteristics other than those originally specified is fired. Based on the technical literature, our engineering judgement is that a boiler will be burning a fuel type at more than 10% on an annual heat input basis only if it was designed for that specific fuel type. The National Energy Technology Laboratory of the Department of Energy has recommended when co-firing with coal, biomass or other co-firing materials should be limited to 10 percent to reduce or eliminate operation problems. (National Energy Technology Laboratory, 2009). In addition, test burn data from a coal-fired boiler co-firing biomass showed that the CO emission increased by 200 percent (from 98 ppm at 100% coal to 286 ppm at 90% coal/10% biomass) when co-firing 10 percent biomass. One of the criteria for subcategorization is differences in the nature of emissions. The subcategories were defined in such a manner so that all combination fuel-fired boilers would be covered by one of the subcategories. We believe it is unlikely that a boiler designed to burn coal would operate at 11% biomass and 89% coal just to be covered by one of the biomass subcategories. First, the unit may experience operational problems or need to be derated because biomass tends to have a high moisture content which reduces heating value and requires a larger volume boiler with larger auxiliary equipment (e.g., fans). In addition, the unit would be subject to the same mercury and HCl emission limits regardless of its fuel mix. The main difference would be the CO emission limit it is subject to which is appropriate because it is the combustion related pollutants that was the basis for the subcategorization.

As previously stated in the June 2010 proposal preamble (75 FR 32016-32017) and the March 2011 final rule preamble (76 FR 15635), the CAA allows EPA to divide source categories into subcategories based on differences in class, type, or size. For example, differences between given types of units can lead to corresponding differences in the nature of emissions and the technical feasibility of applying emission control techniques. The design, operating, and emissions information that EPA has reviewed indicates differences in unit design that distinguish different types of boilers. Data indicate that there are significant design and operational differences between units that burn coal, biomass, liquid, and gaseous fuels. [\[1\]](#)

Industrial boilers use heat to convert water into steam for a variety of applications. Steam flow rates and operating conditions (e.g., temperature and pressure) are the principal design considerations. The primary fuel has perhaps the most significant impact on the boiler configuration and design. When fossil or biomass fuels are burned, widely differing provisions are made to account for differences in fuel handling and preparation, fuel combustion, heat recovery, fouling of heat transfer surfaces, corrosion of materials, and emission controls. For example, in a natural gas-fired boiler, only a small furnace (i.e., combustion chamber) is needed for combustion and closely spaced heat transfer surfaces may be used because of a lack of ash deposits (fouling). For units firing a solid fuel such as coal (which can contain a significant amount of noncombustible ash), the systems must include a much larger furnace, more widely spaced heat transfer surfaces, and an ash removal system. The fuel and the combustion system define the design geometry of the furnace. The furnace volume is set to allow complete fuel

combustion. Adequate clearances are specified to prevent flame impingement on the furnace surfaces, which could overheat the tubes and cause tube failures.[2]

A variety of boiler systems are used to handle the variety of fuel characteristics and boiler sizes. Boiler systems that are designed for burning coal include pulverized coal (PC) units, stokers, and fluidized-bed combustion (FBC) units. Boiler systems that are designed for burning biomass fuels include stokers, Dutch ovens (pile burners), suspension burners, grate burners, and fluidized bed burners. All of these boiler designs have their strengths and weaknesses depending on the particular application.

Boiler systems are designed for specific fuel types and will frequently encounter combustion, slagging, fouling, or ash handling problems if a fuel with characteristics other than those originally specified is fired.[3] For example, the fuel feed rate for wood for a given heat input is about twice that of coal on a weight basis, and more than four times that of coal on a volume basis. Also, a combination of wood and coal firing often produces worse slagging and fouling conditions than coal firing alone. Wood combustion requires more excess air and more overfire air than coal combustion.[4] The National Energy Technology Laboratory of the Department of Energy has recommended when co-firing with coal, biomass or other co-firing materials should be limited to 10 percent on a weight basis to reduce or eliminate operation problems. (National Energy Technology Laboratory, 2009) The fuel has a major impact on boiler design due to fouling and erosion characteristics of the flyash and heat transfer properties of the fuel gas (including moisture content). Biomass requires significantly different combustion systems than coal, oil, or gas and can also result in different boiler corrosion characteristics. Changes to the fuel type would generally require extensive changes to the fuel handling and feeding system (*e.g.*, a stoker using wood as fuel would need to be redesigned to handle fuel oil or gaseous fuel). Additionally, the burners, combustion chamber, and combustion air system (*i.e.*, fans) would need to be redesigned and modified to handle different fuel types and account for increases or decreases in the fuel volume. In some cases, the changes may reduce the capacity and efficiency of the boiler or process heater. An additional effect of these changes would be extensive retrofitting needed to operate using a different fuel.

The design of the boiler or process heater, which is dependent in part on the type of fuel being burned, impacts the degree of combustion. Boilers and process heaters emit a number of different types of HAP emissions. Organic HAP are formed from incomplete combustion and are influenced by the design and operation of the unit. The degree of combustion may be greatly influenced by three general factors: time, turbulence, and temperature. In any energy application the combustion unit is designed to make the best use of time, turbulence, and temperature. All three of these aspects relate directly to the properties of the fuel to be used (moisture content, particle size, ash content, and heat value). On the other hand, the formation of fuel-dependent HAP (metals, mercury, and acid gases) is dependent upon the composition of the fuel. These fuel-dependent HAP emissions generally can be controlled by either changing the fuel property before combustion or by removing the HAP from the flue gas after combustion.

We first examined the HAP emissions results to determine if subcategorization by unit design type was warranted. We concluded that the data were sufficient for determining that a distinguishable difference in performance exists based on unit design type. Therefore, because different types of units have different emission characteristics which may influence the feasibility of effectiveness of emission control, they should be regulated separately (*i.e.*,

subcategorized). Accordingly, we subcategorized boilers and process heaters based on unit design in order to account for these differences in emissions and applicable controls.

For the fuel-dependent HAP (metals, mercury, acid gases), we identified five basic unit types as subcategories. These are the following: (1) units designed to burn coal, (2) units designed to burn biomass, (3) units designed to burn liquid fuel, (4) units designed to burn natural gas/refinery gas, and (5) units designed to burn other process gases. Within the basic unit types there are different designs and combustion systems that, while having a minor effect on fuel-related HAP emissions, have a much larger effect on organic HAP emissions due to the geometry of the combustion chamber and how combustion air is introduced into the boiler. Organic HAP are unburned fuel or the products of incomplete combustion. Therefore, we decided to further subcategorize based on these different unit designs in establishing standards for organic HAP emissions. We have identified the following 11 subcategories for organic HAP:

- Pulverized coal units,
- Stokers designed to burn coal,
- Fluidized bed units designed to burn coal,
- Stokers designed to burn biomass,
- Fluidized bed units designed to burn biomass,
- Suspension burners/Dutch Ovens designed to burn biomass,
- Fuel Cells designed to burn biomass,
- Units designed to burn liquid fuel,
- Units designed to burn natural gas/refinery gas,
- Units designed to burn other gases, and
- Metal process furnaces.

These subcategories are the different boiler system (designs) types used primarily in the source category and are based on the primary fuel that the boiler or process heater is designed to burn. Therefore, the subcategories are defined to account for the fact that boilers designed for a specific fuel type will encounter operational problems if another fuel type, that was not considered in its design, is fired at more than 10 percent of the heat input to the boiler. Units designed as “combination boilers”

Generally, boilers are designed based on a specific fuel type. However, certain industrial sectors employ “combination boilers” that are designed for fuel flexibility to burn both coal and biomass. These combination boilers require a compromise in its design, adopting design features of "coal units" and "biomass units". These design features often result in performance (e.g., combustion/boiler efficiency) compromises but are adopted for fuel flexibility in order to maintain steam production if the primary fuel supply is curtailed. These combination boilers are generally of the stoker design. One compromise is in the design of the stoker. The design of the stoker width and depth is related to the specific fuel. A high heating value, low moisture fuel (i.e., coal) would require a wider, less deep stoker because coal will tend to burn more rapidly. A low heating value, high moisture fuel (i.e., wood/biomass) would require a narrow, deeper

stoker because more residence time on the stoker is usually needed. Another compromise needed is in the fuel feeding system. When biomass is burned with coal in a stoker, the biomass is introduced to the furnace through a separate conveying system. Also, the amount of ash from coal is greater than the amount from biomass. Therefore, the design parameters for the coal (slagging and fouling) will govern the design. Another compromise is in the design of the combustion system. The split between undergrate air and overfire air flows in a stoker type boiler depends largely upon fuel size, volatility and moisture content. For biomass firing, a higher portion of the combustion air requirement is supplied as overfire air than when firing coal. The design of these combination boilers effects the organic HAP emissions.

Because combination boilers are designed to burn both biomass and coal, either alone or as a mixture, it would not be appropriate to classify combination boilers as being in one of the “coal” subcategories because the boiler design is such that when burning greater than 10% biomass, even at a mixture of 11% biomass/89% coal, the combination boiler has an organic HAP/CO emission profile that is similar to units designed to burn 100% (or nearly 100%) biomass. Whereas, a boiler designed to burn coal as it primary fuel could not combust more than 10% biomass or a boiler designed to burn biomass could not combust more than 10% coal without significant retrofitting or design changes. Therefore, to account for these combination boilers in the appropriate subcategories, we continue to define boilers and process heaters that burn at least 10 percent biomass (on an annual heat input basis) as being in one of the biomass subcategories. We also continue to define boilers and process heaters that burn at least 10 percent coal but less than 10 percent biomass (on an annual heat input basis) as being in one of the coal subcategories. We define boilers and process heaters that burn at least 10 percent liquid fuel, and less than 10 percent solid fuel and less than 10 percent biomass (on an annual heat input basis) as being in the liquid subcategory. We continue to define boilers and process heaters that burn only natural gas and/or refinery gas (on an annual heat input basis) as being in the Gas 1 subcategory. This would ensure that each boiler and process heater is subject to emissions standards calculated on the basis of the best performing units with similar design and operation. The remaining boilers and process heaters would be in the Gas 2 subcategory.

[1] EPA did not, as some commenters suggest, subcategorize boilers and process heaters based on fuel type. However, EPA disagrees that subcategorizing based on material inputs would be inconsistent with the CAA. Nothing in the statute prohibits EPA from subcategorizing based on material inputs. *See Sierra Club v. Costle*, 657 F.2d 298, 318-19 (D.C. Cir. 1981) (differing pollutant content of input material can justify a different standard based on subcategorization authority to “distinguish among classes, types and sizes within categories of new sources”). Had Congress intended to prohibit subcategorization based on material inputs, it would have clearly stated that prohibition in the statute. Instead, it used the broad terms “class, type, or size” to authorize EPA to subcategorize sources. Given that the authority to subcategorize is discretionary, as evidenced by the use of the word “may” in section 112(d), the Agency does believe that it could decline to exercise that authority even if the potential result would be the prohibition of use of certain materials, if the circumstances warranted.

[2] Steam/its generation and use, Edition 41, The Babcock & Wilcox Company, a McDermott Company

[3] Steam/its generation and use, Edition 41, page 19-4, The Babcock & Wilcox Company, a McDermott Company

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 6

Comment: The "designed to burn" concept underlying all of EPA's fuel-based subcategories is further undermined by the agency's definition of this same term to mean "can burn" or "does burn" in its proposed revisions to the non-hazardous secondary material (NHSM) definition. 76 Fed. Reg. 80,452, 80,480-80,481 (December 23, 2011). There, the agency claims that a unit is "designed to burn" a given fuel so long as it "can burn" that fuel or "does burn" that fuel, regardless of whether its air permit lists that fuel. *Id.* That claim belies the agency's previous claim that sources that can and do burn different materials as fuel are a different class type or size of source because they are allegedly "designed to burn" a specific fuel. As EPA itself recognizes in the NHSM rule, the "designed to burn" concept is essentially meaningless and gives way to what sources actually can and do burn when it suits the agency's policy interests. The conflicting meanings that EPA gives the term "designed to burn" in its boilers and NHSM rules and EPA's failure to reconcile the conflict renders both rules arbitrary and capricious.

Response: The NHSM rule was issued pursuant to the Resource Conservation and Recovery Act (RCRA), and does not relate to EPA's discretion to establish subcategories under section 112 of the CAA. Under section 112, EPA may distinguish between sources based on class, type, or size, and as explained elsewhere in the record for today's action, EPA's has done so in establishing subcategories within the boiler and process heater source category. These subcategories are based on EPA's evaluation of information relating to the different types of boilers and process heaters, as well as emissions test data identifying differences in emissions due to differences in types of boilers. The NHSM rule, in contrast, establishes EPA's interpretation of the RCRA-defined term "solid waste" for non-hazardous secondary materials. Thus, the purpose of the NHSM rule -- to identify non-hazardous secondary materials that are solid waste -- is different than that of this action. The contaminant comparison criterion in that rule is part of the overall approach developed to distinguish between materials that are solid waste when combusted and those that are not, and is unrelated to distinguishing between classes, types, and sizes of boilers and process heaters as well as to establishing emissions limits for these sources.

However, we disagree that the concept underlying the subcategorization that boilers are designed for specific fuel types is undermined by the EPA's definition of designed to burn in the NHSM definition. As stated in the June 2010 proposal preamble (75 FR 32017) and in various technical document (see "Steam/its generation and use" by The Babcock & Wilcox Company), boiler systems are designed for specific fuel types and will encounter problems if a fuel with characteristics other than those originally specified is fired. The design of the boiler, including the size and shape of the furnace, the spacing of the boiler tubes, and the size and location of the combustion air system, is a function of the combustion characteristics, fouling and slagging characteristics, ash analysis, etc. of the fuel type selected. Burning another fuel type would be

physically impossible with modification to the boiler and fuel handling system. For example, in firing biomass in a boiler designed for coal, wood (i.e., biomass) fuel feed rate for a given heat input is about twice that of coal on a weight basis, and more than four times that of coal on a volume basis. In addition, wood combustion requires more excess air and more overfire air than coal combustion and a combination of wood and coal firing often produces worse slagging and fouling conditions than coal firing alone.

The definition of “Unit designed to burn ...” in the final rule is based on the actual annual heat input of the specific fuel type. Based on the technical literature, our engineering judgement is that a boiler will be burning a fuel type at more than 10% on an annual heat input basis only if it was designed for that specific fuel type. The NHSM definition of “designed to burn” is for determining if the secondary material is comparable in contaminants to a tradition fuel. NHSM definition of contaminants is:

Contaminants means any constituent in non-hazardous secondary materials that will result in emissions of the air pollutants identified in Clean Air Act section 112(b) or the nine pollutants listed under Clean Air Act section 129(a)(4)) when such non-hazardous secondary materials are burned as a fuel or used as an ingredient, including those constituents that could generate products of incomplete combustion.

Thus, if the secondary material is determined to be comparable, the secondary material when combusted would have similar emissions to the traditional fuels and under the Boiler MACT would be considered, that is, meets the definition of, either a “Solid fossil fuel,” “Biomass or bio-based solid fuel,” or “Liquid fuel.”

Commenter Name: Mary Sullivan Douglas

Commenter Affiliation: National Association of Clean Air Agencies (NACAA)

Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1

Comment Excerpt Number: 14

Comment: EPA proposes, however, to subdivide these broad categories into 38 subcategories for existing and new units. In support of the explosion in the number of subcategories, EPA explains the differences in design between, for example, a coal-fired stoker boiler and a coalfired pulverized coal (“PC”) boiler. However, large boilers do not come off an assembly line¹² and can last for up to 50 years. Almost every large boiler will have differences in design from every other large boiler. Even smaller boilers will have differences in design from small boilers produced by other manufacturers. As a result, it is insufficient to simply identify design differences. Where EPA seeks to establish additional subcategories it must explain why those differences matter and point to information in the record that supports its conclusion. For example, within the Boiler MACT “coal-fired” category, EPA proposes separate subcategories for stoker, fluidized bed and pulverized coal designs. However, we know of no reason why well-controlled units of these designs should differ significantly in levels of HAP emissions.

[Footnote]

(12) Even mass-produced automobiles will exhibit design differences within and between models and manufacturers.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Mary Sullivan Douglas

Commenter Affiliation: National Association of Clean Air Agencies (NACAA)

Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1

Comment Excerpt Number: 33

Comment: When a source combusts only one type of fuel at all times, determining which emission limit to apply is straightforward. However, many sources combust different types of fuels at different times and a substantial number of sources combust different mixtures of these fuels at different times. In developing its Model Permit Guidance,³⁵ NACAA attempted to address this issue by examining test results where only one type of fuel is employed to set the recommended range of suggested limits. It was anticipated that state and local permitting authorities would then determine the appropriate procedure for establishing permit limits on a case-by-case basis, either by applying the limit that was the most stringent at all times, by determining the weighted average of relevant limits or by requiring a compliance demonstration based on full utilization of one fuel. EPA has taken a different approach. It has adopted a “designed to combust” test and a hierarchical scheme for determining the fuel category of a source.

1. If a source generates more than 10 percent of its heat from biomass, it is in the biomass category.
2. If it uses less than 10 percent biomass and more than 10 percent coal it is in the coal category.
3. If it burns oil, but less than 10 percent coal and less than 10 percent biomass it is in the liquid-fired category.
4. If it burns any amount of gas other than natural gas (Gas 1) it is in the Gas 2 category.

EPA has not explained the rationale for this approach, which places many sources in fuelcategories other than those that dominate emissions. This approach also appears to invite “category shopping” and does not seem to address all possible combinations. For example, if a fluidized bed boiler burns 91 percent coal and 9 percent biomass, the proposed CO limits are 56 ppm. If that same boiler combusts 90 percent coal and 10 percent biomass, the proposed CO limits are 370 ppm. This change is far larger than what one would expect based on such a small difference in the fuel combusted.

[Footnote]

(35) See <http://www.4cleanair.org/Documents/RHAP.pdf>.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Work Practices

8A. Tune-Up Requirements

Commenter Name: William C. Herz

Commenter Affiliation: The Fertilizer Institute (TFI)

Document Control Number: EPA-HQ-OAR-2002-0058-3448-A1

Comment Excerpt Number: 4

Comment: The Proposed Rule also includes a contradiction regarding the timing for a tune-up. As set forth in the Proposed Rule's regulatory language: "As applicable, inspect the burner, and clean or replace any components of the burner as necessary (you may delay the burner inspection until the next scheduled or unscheduled unit shown)."¹² On the other hand, the preamble to the Proposed Rule appears to limit the tune-up only to scheduled shutdowns: "Instead, we are proposing that burner inspections that cannot be completed during a tune-up can be delayed until the next scheduled shutdown."

Response: Section 63.7540(a)(10)(i) of the final rule as been revised to be consistent with EPA's intent, as explained in the preamble to the proposed rule. That is, the burner inspection can be delayed until the next scheduled unit shutdown.

Commenter Name: William C. Herz

Commenter Affiliation: The Fertilizer Institute (TFI)

Document Control Number: EPA-HQ-OAR-2002-0058-3448-A1

Comment Excerpt Number: 5

Comment: Unscheduled shutdowns may only last a very short duration and this duration would not allow adequate time for the burner inspection to be completed. EPA includes a definition of shutdown in the Proposed Rule as follows, "Shutdown means the period that begins when a unit last operates at 25 percent load and ending with a state of no fuel combustion in the unit."¹⁴ As an example, for steam methane reformers, which are found in both refineries and ammonia plants, an "unscheduled" shutdown may only last a few minutes, but the burner inspections could take more than 10 days. Thus, using the definition of "shutdown" provided in the Proposed Rule and applying it to the discussion of "unplanned shutdowns" may require the unit to be taken out of service for an extended period of time. This does not appear to be EPA's intent.

TFI supports EPA's preamble language discussion limiting the tune-up to the next scheduled shutdown and requests that EPA revise the regulatory language to that end.

Response: We agree; see the response to comment EPA-HQ-OAR-2002-0058-3448-A1, excerpt 4.

Commenter Name: Russell A. Wozniak

Commenter Affiliation: The Dow Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3449-A1

Comment Excerpt Number: 6

Comment: EPA's proposed rule in 40 CFR 63.7540(a)(10)(i) regarding annual or biennial burner inspection requirements states that the owner/operator may delay the burner inspection until the next scheduled or unscheduled unit shutdown. Dow generally supports these provisions, but is concerned with the new requirement to address the burner inspection, cleaning, or replacement components of the burner during an unscheduled shutdown. When an unscheduled shutdown occurs, typically our sites will need to return the boiler or process heater back to operation as soon as possible to minimize the impact of steam loss or the loss of a process heater. EPA's rule amendments should include the 36 month concept that was contained in the March 21, 2011 final rule to allow some flexibility when dealing with unplanned shutdown. The owner/operator should not be required to conduct a burner inspection during an unscheduled shutdown if a burner inspection has occurred in the previous 36 months. Suggested rule text is provided below:

(1) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (you may delay the burner inspection until the next scheduled or unscheduled unit shutdown). A burner inspection is not required during an unscheduled unit shutdown if the most recent burner inspection has occurred within the last 36 months).

Response: See the response to comment EPA-HQ-OAR-2002-0058-3448-A1, excerpt 4.

Commenter Name: Jessica Bridges

Commenter Affiliation: United States Clean Heat & Power Association (USCHPA)

Document Control Number: EPA-HQ-OAR-2002-0058-3501-A1

Comment Excerpt Number: 8

Comment: We appreciate EPA removing the every 36-month inspection provision if it would require the unit to shut down when it would not have otherwise been required to power down. It is appropriate to propose that burner inspections that cannot be completed during tune-up should be delayed until the next scheduled shutdown.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3448-A1, excerpt 4.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 47

Comment: Burner inspections should not be required for unplanned BPH outages, unless the inspections can be performed without extending the outage or causing other problems.

§63.7540(a)(10)(i) specifies that burner inspections for BPH that cannot be performed with the BPH in-service must be performed at the next planned or unplanned outage. Requiring these inspections in the event of any unplanned boiler or process heater outage has potentially serious economic and unit integrity ramifications and the tune-up inspections should only be required for unplanned outages where the BPH will be totally cooled and only if the unplanned outage is of long enough duration to allow the inspections without extending the outage and if it is consistent

with good engineering judgment (e.g., will not cause safety, equipment damage or other problems).

Response: See the response to comment EPA-HQ-OAR-2002-0058-3448-A1, excerpt 4.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 48

Comment: We strongly support EPA's sensible decision not to require BPH shutdowns in order to perform burner inspections (part of the tune-up). As EPA describes on page 80614 of the proposal preamble, it is reasonable that "burner inspections that cannot be completed during a tune-up can be delayed until the next scheduled shutdown." For clarity, we request EPA make clear in the regulatory language that this delay is allowed until the next scheduled shutdown of the BPH and is not required if other portions of the associated process are shutdown. Unnecessary shutdowns of BPH are to be avoided because of the potential damage to the boiler or process heater (particularly to the refractory) when it undergoes a cool down and heat up cycle. Thus, it should be clear that the delayed burner inspections are only required if the boiler or process heater is shutdown and cooled off for other reasons.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3448-A1, excerpt 4.

Commenter Name: William C. Herz

Commenter Affiliation: The Fertilizer Institute (TFI)

Document Control Number: EPA-HQ-OAR-2002-0058-3448-A1

Comment Excerpt Number: 3

Comment: Both the final *Industrial Boiler Major Source NESHAP* and the Proposed Rule contain an annual inspection program for units in the Gas 1 subcategory.⁷ The final *Industrial Boiler Major Source NESHAP* allows the annual burner inspection to be delayed until the next scheduled shutdown of the unit, provided the inspection occurs at least once every 36 months.⁸ In the Proposed Rule, the "at least once every 36 months" requirement is proposed for removal.⁹ TFI supports this part of the Proposed Rule.

In its comments on the proposed *Industrial Boiler Major Source NESHAP*, TFI urged EPA to recognize limitations associated with inspecting the burners in a reformer on an annual basis.¹⁰ As noted by TFI, burner adjustments or pulling burners while units or associated process equipment are operating may present worker and/or safety hazards. Further, not all boilers and process heaters can be readily shutdown, which is required for reformers, and the reformer cannot be spared or shutdown without shutting down the entire ammonia manufacturing process.

In its response to TFI's comments on this issue, EPA stated "[a]s long as owners/operators complete the parts of the tune-up that can be completed, they can postpone impractical requirements until the next scheduled outage."¹¹ This suggests that the time period between outages is determined by the owner/operator of the unit, or based on industry-recognized

standards such as ASME Section 1. However, as previously discussed, the regulatory language in the final *Industrial Boiler Major Source NESHAP* (at 40 C.F.R. § 63.7540(a)(10)(i)) provides contrary language – that the inspection must occur at least every 36 months.

Response: The EPA thanks the commenter for their support. Section 63.7540(a)(10)(i) in the final amended rule is consistent with what was proposed. That is, 63.7540(a)(10)(i) in the final amended rule reads as follows:

(i) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (you may delay the burner inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the burner inspection until the first outage, not to exceed 36 months from the previous inspection. At units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or process equipment;

Commenter Name: John C. Hendricks

Commenter Affiliation: American Electric Power (AEP)

Document Control Number: EPA-HQ-OAR-2002-0058-3455-A1

Comment Excerpt Number: 2

Comment: American Electric Power (AEP) supports the clarifications made to the tune-up provisions in the IB Boiler MACT Rule. The actions being enacted by this rule are consistent with the inspections and maintenance usually performed to maintain an efficiently operating boiler. AEP agrees the descriptions in this proposal are proper for industrial and commercial boilers that operate on an intermittent basis and not the primary energy source for the facility.

Response: The EPA thanks the commenter for their support.

Commenter Name: Lee Zeugin and Lauren Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1

Comment Excerpt Number: 8

Comment: UARG also supports the changes that EPA proposes to make to the tune-up work practice requirements. In particular, UARG supports changes that do not cause units to shutdown solely for the purpose of conducting burner inspections and that do not require physical burner inspections where those inspections cannot be reasonably completed.

Response: The EPA thanks the commenter for their support.

Commenter Name: Jessica Bridges

Commenter Affiliation: United States Clean Heat & Power Association (USCHPA)

Document Control Number: EPA-HQ-OAR-2002-0058-3501-A1

Comment Excerpt Number: 10

Comment: EPA is correct in clarifying that when a burner inspection is difficult or impossible to meet they will not require a physical inspection “that cannot reasonably be completed.”

Response: The EPA thanks the commenter for their support.

Commenter Name: David A. Buff, Golder Associates Inc.
Commenter Affiliation: Florida Sugar Industry (FSI)
Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1
Comment Excerpt Number: 43

Comment: The FSI supports the proposed changes to the boiler tune-up requirements because they provide more flexibility for the regulated community.

Response: The EPA thanks the commenter for their support.

Commenter Name: Michael L. Krancer
Commenter Affiliation: Pennsylvania Department of Environmental Protection (DEP)
Document Control Number: EPA-HQ-OAR-2002-0058-3507-A1
Comment Excerpt Number: 15

Comment: The EPA has proposed several changes to the tune-up requirements and timing of completing the various aspects of tune-ups. The reconsidered proposal removes the "every 36 months" burner inspection requirement. In response to petitioners, burner inspections that cannot be completed during a tune-up can be delayed until the next scheduled shutdown. The petitioners also requested that CO adjustments as part of a tune-up be allowed to be completed within 30 days of the tune-up. Additionally, EPA is clarifying that a physical inspection of the burner that cannot reasonably be completed is not required.

The DEP agrees with the proposed revisions to the tune-up provisions.

Response: The EPA thanks the commenter for their support.

Commenter Name: Mary Sullivan Douglas
Commenter Affiliation: National Association of Clean Air Agencies (NACAA)
Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1
Comment Excerpt Number: 48

Comment: NACAA agrees with the industry suggestion and EPA proposal that sources be allowed 30 days to make the adjustments in order to allow for multiple adjustments to optimize CO emissions.

Response: The EPA thanks the commenter for their support.

Commenter Name: Richard Krock
Commenter Affiliation: The Vinyl Institute
Document Control Number: EPA-HQ-OAR-2002-0058-3526-A1
Comment Excerpt Number: 7

Comment: The VI also supports the ability to delay the burner inspection required as part of the tune-up until the next scheduled or unscheduled unit shutdown, to prevent unnecessary disruption of operations.

Response: The EPA thanks the commenter for their support.

Commenter Name: Linda Miller

Commenter Affiliation: New Jersey Department of Environmental Protection (NJDEP)

Document Control Number: EPA-HQ-OAR-2002-0058-3664-A2

Comment Excerpt Number: 4

Comment: We support the proposed tune up work practice standard for ICI boilers. New Jersey has similar requirement already in place.

Response: The EPA thanks the commenter for their support.

Commenter Name: Pamela Lacey

Commenter Affiliation: American Gas Association (AGA)

Document Control Number: EPA-HQ-OAR-2002-0058-3672-A2

Comment Excerpt Number: 3

Comment: AGA supports EPA's proposals to make the tune-up requirements more workable and to avoid unintended consequences, as requested by other petitioners. See 76 Fed. Reg. 80614.

Response: The EPA thanks the commenter for their support.

Commenter Name: Heather Parent

Commenter Affiliation: Maine Department of Environmental Protection

Document Control Number: EPA-HQ-OAR-2002-0058-3691-A2

Comment Excerpt Number: 15

Comment: Maine DEP supports EPA's proposed 30 day allowance for completing any required CO adjustments to a unit following completion of a tune-up in order to allow sufficient time for multiple adjustments and optimization of CO emissions to occur.

Response: The EPA thanks the commenter for their support.

Commenter Name: Jessica Bridges

Commenter Affiliation: United States Clean Heat & Power Association (USCHPA)

Document Control Number: EPA-HQ-OAR-2002-0058-3501-A1

Comment Excerpt Number: 9

Comment: EPA is correct in setting a period of 30 days after the tune-up for making CO adjustments and optimization.

Response: Section 63.7540(a)(13) of the final rule has been revised to be consistent with the proposal preamble language for allowing 30 days after startup to conduct the tune-up.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 50

Comment: Allowing 30 days for CO adjustments to be completed after the tune-up inspections and adjustments is a very important change, since many tune-ups will be done with the BPH out-of-service, making CO adjustments impossible until the unit is back in service and because the tune-up inspections may result in burner changes that impact emissions. We strongly support this reasonable change.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3501-A1, excerpt 9.

Commenter Name: Arthur N. Marin

Commenter Affiliation: Northeast States for Coordinated Air Use Management (NESCAUM)

Document Control Number: EPA-HQ-OAR-2002-0058-3506-A1

Comment Excerpt Number: 23

Comment: NESCAUM urges the EPA to require tune-ups for wood-fired boilers. As currently proposed by the EPA, the tune-up requirements for other boiler types are not appropriate for wood-fired boilers. As an alternative, NESCAUM is currently working with EPA Region 1 to develop regional guidance for what would constitute appropriate requirements for tuning a biomass boiler. NESCAUM recommends that the EPA adopt this regional guidance as national guidance for biomass boiler tune-ups.

Response: EPA is not adopting a tune-up requirement that is specific for wood-fired boilers which generally are stokers. The tune-up requirement in 63.7540 is general with certain requirement only required (e.g., inspect the burner) if applicable. The EPA appreciates NESCAUM's effort to develop a regional guidance for biomass boiler tuneup and we will post it on the EPA webpage when it has been developed.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 79

Comment: *ACC SUPPORTS MODIFICATIONS TO TUNE-UP FREQUENCY AND PROCEDURES FOR VERY LIMITED USE UNITS*

EPA should also reconsider and modify the tune-up provisions for process heaters that operate on a very limited basis. The Reconsideration Proposal includes a requirement that a limited use process heater must conduct a tune-up biennially as specified in § 63.7540. Implementation of all of the tune-up requirements for process heaters that are operated on a very limited basis is

problematic due to the few hours per year that some of these devices operate. In some cases, small start-up heaters run for about one hour at a time and they typically only run a handful of times a year at random times on an as needed and often unplanned basis. They are only and can only be used during a very limited time, i.e., startup of the process to pre-heat a process material prior to the reactor coming on line. Because of the shortness of this time period, it is not possible to optimize the system to reduce CO emissions and conduct CO emission screening before and after the adjustments. The Dow Chemical Company, an ACC member company, advocated in its comments that these limited use process heaters should only be subject to a recordkeeping requirement.²⁶ At a minimum, the tune-up requirements in §63.7540(a)(10) need to be modified to reflect the fact that the only element of the work practice that can be executed for these very limited use process heaters is § 63.7540(a)(10)(i) regarding burner inspections and replacements.

[Footnote 26: See Docket ID No. EPA-HQ-OAR-2002-0058-2632]

Response: We agree and §63.7540(a)(12) of the final rule has been revised to require tune-ups for limited-use units every 5 years instead of biennial. The proposed rule would have been more burdensome on units with short seasonal, or limited, operations than on units operating year round. The seasonal/limited use nature means that each unit must undergo tune-ups every two to three months of operation. This is far more frequent than envisioned by the proposed rule of conducting a tune-up every 12 months of operation. We have revised the final rule to address the issue by requiring limited-use units to complete subsequent tune-up every five years.

We understand that there may be certain process heaters for which scheduling a tune-up may be difficult. However, giving a blanket exception is not appropriate nor necessary to address the scheduling concerns. Requiring tune-ups every 5 years for limited-use units should provide sufficient time in which to schedule and conduct a tune-up.

Commenter Name: Sarah Hedrick

Commenter Affiliation: Verso Paper Corp.

Document Control Number: EPA-HQ-OAR-2002-0058-3537-A2

Comment Excerpt Number: 5

Comment: Section 63.7540 a(12) of the draft rule requires limited use boilers to perform biennial tune-ups.

63.7540 a(12) references the requirements in 63.7540 a(10) which specify that the biennial tuneup include measurements of CO, records of CO measurements before and after the adjustments made during the tune-up, and inspections of flame patterns. It is too costly to require a very large limited use boiler to start up and run just to meet the requirement to perform biennial tune-ups, as explicitly outlined in the rule. Some limited use boilers will not run at any point during a two year period. (Paragraph 13 of this section does provide some relief in that if a boiler is not operating on the date required for a tune-up, then the tune-up needs to be conducted within one week of startup.)

Limited use boilers often do not run continuously for long enough periods to conduct a live tuneup where CO data can be collected. There is a large energy penalty associated with running a very large boiler solely for tune-up purposes when it is not needed for steam demand. The rule needs to be modified to not explicitly specify how maintenance activities or tune-ups will occur.

The rule does not realistically consider boilers which are maintained in a moth-balled or ready state for emergency use or in order to support maintenance activities on other boilers. Discretion in maintenance activities needs to be left to the facilities.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 79.

Commenter Name: Chris M. Hobson

Commenter Affiliation: Southern Company

Document Control Number: EPA-HQ-OAR-2002-0058-3520-A1

Comment Excerpt Number: 8

Comment: Southern urges EPA to modify the frequency of the boiler tune-up work practice standard to better coincide with outage schedules. Large biomass boilers that serve electricity for sale may not require annual outages and would therefore need to be taken off-line for the sole purpose of an annual tune-up. Southern suggests that EPA modify the requirements such that the tune-up is required at each outage, but no later than once every 36 months. This frequency would be consistent with the requirements of the final Utility MACT standard that EPA finalized on February 16, 2012.⁵

[Footnote]

(5) 77 Fed. Reg. at 9493

Response: We understand the issue with electricity only units and we agree. We have revised Table 3 to be consistent with the requirement in the MATS rule. Our intent was that this work practice standard could be performed in conjunction with routine maintenance operations at a facility and be a logical extension of routine best practices for boiler inspection and optimization. Based on the comments received on this rulemaking and on the MATS rulemaking, for units that produce electricity, the final rule [63.7540(a)(10)(i)] has been revised to allow for the inspection to be delayed until the first outage but not to exceed 3 years from the previous inspection.

Commenter Name: Mary Sullivan Douglas

Commenter Affiliation: National Association of Clean Air Agencies (NACAA)

Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1

Comment Excerpt Number: 49

Comment: NACAA agrees with the suggestion that, where burner inspection is impossible without destroying the unit, it should not occur. In such instances, however, the source should conduct CO monitoring to determine whether the burner has deteriorated to the point that it should be replaced. We do not believe that burner inspections should be waived where they are merely “difficult” as this term is unenforceable. We suggest that such sources be allowed to determine CO baseline emissions after a tune up and thereafter substitute CO testing in lieu of inspection if they prefer.

Response: The EPA thanks the commenter for their support. Under the tune-up provision, if the burner inspection is not possible, the tune-up requirement [63.7540(a)(10)(iv)] of measuring and

optimizing CO emissions must still be conducted. 63.7540(a)(10)(i) only allows for the burner inspection to be delayed, not other parts of the tune-up requirements.

Commenter Name: Bart Sponsellar

Commenter Affiliation: Wisconsin Department of Natural Resources (DNR)

Document Control Number: EPA-HQ-OAR-2002-0058-3527-A1

Comment Excerpt Number: 9

Comment: [If EPA does not exempt small biomass units from regulation], we request that EPA incorporate rule language exempting sources from measuring CO and O₂ flue gas concentrations in cases where it is technically infeasible or it is not pertinent to the boiler tuning over time.

Response: We disagree. Measurements of CO and oxygen can be performed with portable hand-held analyzers. Using performance stack test methods and procedures are not required for the tune-up.

Commenter Name: John M. Cullen

Commenter Affiliation: Masco Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3661-A2

Comment Excerpt Number: 11

Comment: EPA has not changed the proposed work practice requirement for natural gas-fired boilers and process heaters in §63.7540(a)(10)(vi)(C) that would require a source to include in the on-site annual report the "type and amount of fuel used over the 12 months to the annual adjustment". Masco continues to view this requirement as unnecessarily burdensome as most facilities do not presently have such meters installed.

Response: We disagree that this is unnecessarily burdensome. §63.7540(a)(10)(vi)(C) allows for estimating fuel use if such meters are not installed.

Commenter Name: John M. Cullen

Commenter Affiliation: Masco Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3661-A2

Comment Excerpt Number: 12

Comment: Masco continues to assert that a boiler or process heater that has not operated in the previous year should be allowed to forego the annual tuneup requirements.

Response: The final rule already addresses this situation. §63.7540(a) (13) allows for units to delay the tune-up until it is operated.

Commenter Name: Robin Mills Ridgway

Commenter Affiliation: Purdue University

Document Control Number: EPA-HQ-OAR-2002-0058-3668-A2

Comment Excerpt Number: 7

Comment: It is Purdue's understanding that in the proposed rule, tune up records for the work practice standard are only to remain available on site, not to be turned into the agency. Please confirm this is the correct interpretation.

Response: The commenter is correct. 63.7540(a)(10)(vi) only requires that the tune-up records be maintained on site and submitted only upon request by the Administrator.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 49

Comment: We believe the allowance for delay needs to be expanded to include other aspects of the tune-up that also cannot always be done with the unit in service. For instance, proposed 63.740(a)(10)(iii) states: "Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly." Depending upon the equipment design, this requirement may only be able to be safely and effectively completed while the boiler or process heater is shut down. For instance, to determine if a draft controller is operating properly or calibrated properly may require it be moved to a position that would cause an upset to the units operation. Forcing unnecessary boiler or process heater shutdowns in order to complete any of the tune-up requirements is equally unreasonable as forcing shutdowns for burner inspections and thus should also be allowed to be delayed when necessary.

Response: We agree with the commenter that other aspects of the tune-up requirement in addition to the boiler inspection cannot be performed when the unit is operating. For example, inspection of the system controlling the air-to-fuel ratio. In the final amended rule, 63.740(a)(10)(iii) has been revised in the final rule to be similar to 63.740(a)(10)(i).

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 51

Comment: Some process heaters cannot be accessed on even a five year cycle and further delay of repair should be allowed for them. For instance, some process heaters are installed in tanks and entry into the tank to access the heater may not occur within a five year period. Where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections should only be required when the process equipment interior is accessed for other reasons (i.e., only during planned entries into the storage vessel or process equipment).

Response: We understand the concerns raised by the commenter about shutting down process equipment in order to enter them to conduct the inspection of the process heater contained within. We have revised 63.7540(a)(10)(i) in the final rule to address the issue to include the statement "At units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned

entries into the storage vessel or process equipment." However, the main aspects of the tune-up, measuring and optimizing CO emissions to manufacturer's specifications, must still be conducted on the frequency as required by the final amended rule.

Commenter Name: Samuel H. Bruntz

Commenter Affiliation: Alcoa Power Generating, Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3755-A1

Comment Excerpt Number: 13

Comment: Tune-up of Solid Fuel Boilers with a Heat Input Capacity greater than 250 mm Btu/hr.

Table 3 is applicable for any new or existing boiler or process heater with heat input capacity of 10 mm Btu/hr., or greater, and requires that the tune-up requirements proposed in 63.7540, which are designed for the natural gas and metal process furnace subcategories, also be applied for large solid fuel boilers.

The large solid fuel boilers need different tune-up criteria, due to their requirements to *also* comply with low NOx emission limits, and the nature of outages they take.

Alcoa~ Warrick thus proposes that Table 3 be amended to specify the following tune-up requirements for solid fuel boilers with a heat input capacity in excess of 250 mm Btu/hr., as follows:

[See page 7 of the submittal for Table of language suggested by the commenter]

Response: We are aware that some units, not just large solid fuel boilers, will be subject to either Federal or State NOx requirements. The tune-up requirements in 63.7540(a)(10) do not prevent a unit from complying with NOx emission limits. However, in the final rule, 63.7540(a)(10)(iv) has been revised to clarify that "This optimization should be consistent with manufacturer's specification, if available, and with any NOx requirement to which the unit is subject."

Commenter Name: Michael Cassidy

Commenter Affiliation: Kohler Co.

Document Control Number: EPA-HQ-OAR-2002-0058-3803-A1

Comment Excerpt Number: 1

Comment: In the proposed Boiler MACT rule, "tune up" means "adjustments made to a boiler in accordance with procedures supplied by the manufacturer to optimize the combustion efficiency." Many boilers employ "full-metered, cross-limited" combustion control systems. Full-metered control means that both fuel and airflow are continuously measured and controlled separately. Metered control recognizes that variations in fuel feed pressure affect fuel flow and variations in draft pressure affect combustion airflow. Full-metered control permits the independent adjustment of combustion air and fuel flows in order to maintain optimum air/fuel ratio. The benefit of this control system is improved boiler efficiency on a continuous basis.

Cross-limited control is “safety logic” superimposed on a full-metered control system. In the event of a mechanical failure (e.g. jammed fuel valve, blocked air damper), it is possible to create a fuel rich combustion mixture. Cross-limited control prevents combustion airflow from falling below fuel flow and fuel flow from exceeding airflow. Full-metered, cross-limited control systems improve boiler efficiency by continuously compensating for variations in fuel and combustion airflows, and they improve boiler safety with active constraints over the air/fuel combustion mixture. This type of control system employs oxygen trim and fuel/air sensors to continuously monitor fuel flow, air flow, and exhaust gas recirculation flow to continuously ensure the highest possible combustion efficiency. Full-metered, cross-limited control systems are recommended by boiler manufacturers to continuously monitor combustion efficiency, so boiler operators can react to changes that reduce combustion efficiency immediately, for economic and safety reasons.

Kohler Co. believes that boilers utilizing a full-metered, cross-limited combustion control system maintain peak combustion efficiency on a real-time and continuous basis. As these control systems trigger boiler adjustments on an as needed and continual basis, they represent a superior approach to maintaining peak combustion efficiency and minimizing combustion emissions versus the requirement in the proposed MACT rule for a once-per-year boiler tune-up. The annual tune-up requirement in the proposed rule will require many sources with this control technology to expend significant funds with no improvement in efficiency or environmental benefit (reduced emissions). As such, Kohler Co. requests that full-metered, cross-limited control systems be included as a compliance alternative to the annual tune-up requirement in the proposed rule. Specifically, for boilers with full-metered, cross-limited combustion controls, 40 CFR §63.7540(10), items (i) through (vi) can be replaced with requirements to: (i) calibrate weekly the oxygen trim sensors, (ii) calibrate annually the air/fuel control system components, and (iii) maintain on-site records of calibrations and maintenance activity, as well as data storage of the oxygen trim and air/fuel control systems operation and performance.

Response: We agree that units with oxygen trim systems or "full-metered, cross-limited" combustion control systems that maintain optimum air/fuel ratio may not benefit from annual tune-ups because these systems trigger boiler adjustments on an as needed basis. 63.7540 of the final rule has been revised to required units with these types of combustion control systems to conduct a tune-up on a less frequent basis (i.e., once every 5 years) which is deemed sufficient to verify calibration of the trim or combustion control system.

8B. Small Unit Tune-up

Commenter Name: Dakota Gasification Company Great Plains Synfuels Plant

Commenter Affiliation: David W. Peightal

Document Control Number: EPA-HQ-OAR-2002-0058-3424

Comment Excerpt Number: 10

Comment: DGC agrees with EPA on the tune-up work practice standard for small and limited use units to have a tune-up every 5 years.

Response: The EPA thanks the commenter for their support.

Commenter Name: Felix Mestey, on behalf of Donald R. Schregardus
Commenter Affiliation: Clean Air Act Services Steering Committee, Department of Defense (DoD)

Document Control Number: EPA-HQ-OAR-2002-0058-3427

Comment Excerpt Number: 15

Comment: DoD also supports EPA's decision to reduce the required tune-up frequency for Gas 1 boilers rated less than 5 MMBtu/hr heat input to once every five years;

Response: The EPA thanks the commenter for their support.

Commenter Name: Bruce W. Ramme

Commenter Affiliation: Wisconsin Electric Power Company (WE Energies)

Document Control Number: EPA-HQ-OAR-2002-0058-3452-A1

Comment Excerpt Number: 4

Comment: We Energies supports EPA's proposal to reduce the frequency of a boiler tuneup requirement for small and limited-use boilers and process heaters from once every two years to once every five years as justified in the proposed rule.

Response: The EPA thanks the commenter for their support.

Commenter Name: Barry Christensen

Commenter Affiliation: Occidental Chemical Corporation (OCC)

Document Control Number: EPA-HQ-OAR-2002-0058-3477-A1

Comment Excerpt Number: 3

Comment: OCC supports longer times between tune-ups for the small and liquid fired units, as well as postponement of tune-ups for valid reasons. This includes extending the *tune-up frequency from the proposed annual* requirement to a maximum of 5 years for these boilers. In addition, if a burner inspection can not be accomplished until the next scheduled maintenance outage, a site should be able to delay that tune-up activity up to a maximum of 5 years.

Response: The EPA thanks the commenter for their support.

Commenter Name: Jessica Bridges

Commenter Affiliation: United States Clean Heat & Power Association (USCHPA)

Document Control Number: EPA-HQ-OAR-2002-0058-3501-A1

Comment Excerpt Number: 7

Comment: With EPA rejecting Petitioners requests to exempt small natural gas and light oil fired units (2 MMBtu/hr to 10 MM/Btu/hr) from the rule it correctly decreases the frequency requirement to every five years from every two years for tune-up of smaller natural gas, refinery gas and other clean fuels that meet the fuel specification. However we support setting the upper limit at ≤ 10 MMBtu/hr.

Response: The EPA thanks the commenter for their support.

Commenter Name: Timothy Serie

Commenter Affiliation: American Coatings Association (ACA)

Document Control Number: EPA-HQ-OAR-2002-0058-3502-A1

Comment Excerpt Number: 10

Comment: ACA generally supports the following proposed changes in the Boiler MACT rule:

Proposal that tune-ups for units (equal to or less than 5 MMBtu/hr.) will now only be required by the compliance date and every five years thereafter.

Response: The EPA thanks the commenter for their support.

Commenter Name: Michael L. Krancer

Commenter Affiliation: Pennsylvania Department of Environmental Protection (DEP)

Document Control Number: EPA-HQ-OAR-2002-0058-3507-A1

Comment Excerpt Number: 14

Comment: The EPA has proposed to change the annual tune-up requirement for natural gas, refinery gas, other clean gas, and light liquid-fired units equal to or less than 5 MMBtu/hr to once every five years.

The DEP supports the reduced tune-up frequency for small and limited-use units. DEP believes that requiring a tune-up every five years for these affected sources is reasonable considering the logistical burden for facility owners and operators with a large number of small units.

Response: The EPA thanks the commenter for their support.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 78

Comment: *ACC SUPPORTS THE TUNE-UP FREQUENCY CHANGE FOR SMALL UNITS*

EPA has proposed to change the frequency for tune-ups (following the initial tune-up) for gas and light liquid boilers and process heaters that are equal to or less than 5 MMBtu/hr to a tune-up once every 5 years. (76 Fed. Reg. 80614.) For new units, EPA has proposed to remove the requirement for the initial tune-up, considering that new units will likely be tuned during the initial startup process as part of commissioning. For facilities with a large number of small units, completion of tune-ups on a biennial basis can quickly become a logistics issue, due to the need to schedule periods where the boilers can be tuned without undue disruption to the operation of the facility. ACC believes that a tune-up every 5 years is appropriate for gas and light liquid units 5 MMBtu/hr or less in size, as emissions from these boilers are small, and allowing a reduced tuning frequency will reduce the cost of the rule. Therefore, ACC supports these changes, as they minimize the compliance burden for small units with minimal emissions impact.

Response: The EPA thanks the commenter for their support.

Commenter Name: Shannon S. Broome

Commenter Affiliation: Auto Industry Forum (AIF)

Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1

Comment Excerpt Number: 40

Comment: *In the Alternative, AIF Supports a Less-Frequent Tune-Up Requirement for Certain Units with Heat Input Capacities of 5 MMBtu/hr or Less.*

To the extent that, in lieu of promulgating a *de minimis* exemption, EPA elects to retain work practice standards for most units with heat input capacities of 10 MMBtu/hr or less, AIF supports EPA's proposed change of the biennial tune-up requirement for certain units²⁷ with heat input capacities equal to or less than 5 MMBtu/hr. As explained above, this proposed change fails to account for AIF's analysis that, due to the insignificance of emissions from those units and the considerable administrative burdens associated with regulating them,²⁸ EPA should exempt from the final reconsideration rule NG-fired hot water and process heaters with heat input capacities up to 10 MMBTU/hr. To the extent that EPA finalizes the work practice standards, however, there is a rational basis for decreasing the frequency of the tune-ups for NG-fired, RG, other clean gas such as LFG (that meets the "other Gas 1 fuel" specification) and light liquid-fired units with heat-input capacities of 5 MMBtu/hr or less. In the alternative, then, EPA should finalize the proposed, less-frequent tune-up requirement for those units.²⁹

[Footnote 27: NG-fired, RG, other clean gas such as LFG (that meets the fuel specification) and light liquid-fired units.]

[Footnote 28: Expounding on the cost analysis outlined above, a typical, well-tuned 1 MMBtu/hr burner emitting HAPs at the rate published in EPA's AP-42 NG emissions factor tables, *see Compilation of Air Pollutant Emission Factors, supra*, would emit around 16 pounds of HAP per year. Although highly unlikely, a poorly-tuned unit of this size could emit HAPs at about twice the rate of a well-tuned unit. Then, a facility with twenty poorly-tuned 1 MMBtu/hr burners could collectively emit HAP at a rate of about 1/8 ton per year in excess of well-tuned units. Therefore, using the typical costs noted above, the cost of inspections on a five-year schedule for such units would effectively cost at least \$64,000 per ton abated (or \$160,000 to \$320,000 per ton abated if one assumes a more-typical tuning profile). A hypothetical facility operating two 100 MMBtu/hr boilers and three 12 MMBtu/hr boilers, in addition to the twenty 1 MMBtu/hr burners in the example above, would be spending around 50% of its tune-up budget on the small units to minimize 8% of its HAP emissions due to tune-up requirements. AIF believes that units are generally not "poorly tuned," so the cost per ton, in fact, will be dramatically higher than even estimated here.]

[Footnote 29: Moreover, to the extent that EPA finalizes its proposed work practice standards in lieu of emission limits for certain units, EPA clearly possesses the authority under Section 112(h) of the CAA to issue such standards. The plain text of Section 112(h) provides that EPA may adopt work practice standards instead of emission standards "if it is not feasible in the judgment of the Administrator to prescribe or enforce an emission standard for control of a [HAP]." CAA § 112(h)(1); 42 U.S.C. § 7412(h)(1). The section further explains that it is "not feasible" to set an

emission standard when the “application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations.” CAA § 112(h)(2)(B); 42 U.S.C. § 7412(h)(2)(B). AIF supports the explanation put forth by EPA that it is not feasible with the meaning of the CAA to prescribe or enforce an emission standard for the control of HAP as to the source categories and subcategories for which EPA has prescribed work practice standards in lieu of emission standards.]

Response: The EPA thanks the commenter for their support.

Commenter Name: Robert R. Perry

Commenter Affiliation: FirstEnergy Generation Corp (FGCO)

Document Control Number: EPA-HQ-OAR-2002-0058-3518-A1

Comment Excerpt Number: 3

Comment: If EPA still finds it necessary to impose the burden of tune-up work practice requirements on the regulated community, we support allowing tune-ups once every 5 years. There is no evidence that frequent tune ups will have any impact on emissions.

Response: The EPA thanks the commenter for their support.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 11

Comment: EPA has proposed to change the frequency for tune-ups (following the initial tune-up) for gas and light liquid boilers that are equal to or less than 5 MMBtu/hr to a tune-up once every 5 years (76 Fed. Reg. 80614, Dec. 23, 2011). For new units, EPA has proposed to remove the requirement for the initial tune-up, considering that new units will likely be tuned during the initial startup process as part of commissioning. For facilities with a large number of small units, completion of tune-ups on a biennial basis can quickly become a logistics issue, due to the need to schedule periods where the boilers can be tuned without undue disruption to the operation of the facility. We believe that a tune-up every 5 years is appropriate for gas and light liquid units 5 MMBtu/hr or less in size, as emissions from these boilers are small, and allowing a reduced tuning frequency will reduce the cost of the rule. Therefore, we support these changes, as they minimize the compliance burden for small units with minimal emissions impact.

Response: The EPA thanks the commenter for their support.

Commenter Name: Richard Krock

Commenter Affiliation: The Vinyl Institute

Document Control Number: EPA-HQ-OAR-2002-0058-3526-A1

Comment Excerpt Number: 6

Comment: The VI agrees that tune-ups do not need to be performed annually for small natural gas, refinery gas, other clean gas (that meets the fuel specification) and light liquid-fired units. For these small units (equal to or less than 5 MMBtu/hr), tune-up requirements are appropriately

proposed as once every 5 years, with the initial tune-up required by the compliance date and subsequent tune-ups required at intervals no greater than 5 years from the previous tune-up.

Response: The EPA thanks the commenter for their support.

Commenter Name: Bart Sponsellar

Commenter Affiliation: Wisconsin Department of Natural Resources (DNR)

Document Control Number: EPA-HQ-OAR-2002-0058-3527-A1

Comment Excerpt Number: 7

Comment: EPA in several cases reconsidered the schedule of requirements for smaller oil boilers and limited use boilers. The Department agrees that the frequency of tune-ups for these sub-categories should be reduced because these sources are relatively low emitters. In this context we believe that EPA also needs to apply some bottom threshold at which boilers are subject to the rule requirements. Currently, boiler categories are defined by thresholds such as less than 10 mmBtu/hr or less than 5 mmBtu/hr. This means that even the smallest boiler at an area or major source is subject to the requirement. EPA does not supply a justification for regulating the very smallest emission sources in such an open-ended manner and needs to establish thresholds at which boilers are too small to be subject to the requirements. Clearly, at some level these sources do not contribute to the sources emissions in a significant manner. Further, we find it hard to resolve this issue when all Gas 1 and 2 boilers are subject to requirements under the major source rule while they are not regulated under the area source rule. These sources are exempt under the area source rule because their emissions are deemed to be minor if not insignificant.

Response: The EPA thanks the commenter for their support for the proposed tune-up frequency requirements. However, EPA disagrees that smaller boilers should be exempt from the requirements of the final rule. While emissions from such units may be lower than from larger units, smaller boilers do emit HAP. As explained in the record for the March 2011 final rule, EPA established work practice standards for smaller units in lieu of numeric emissions limits.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 14

Comment: EPA rejected a request to exempt very small (between 2 and 10 MM Btu/hr) oil-fired units. However, EPA has proposed to change the frequency for tune-ups (following the initial tune-up) for boilers or process heaters that are less than 5 MMBtu/hr to a tune-up once every 5 years (76 FR 80644, Dec. 23, 2011). For new units, EPA has proposed to remove the requirement for the initial tune-up, considering that new units will likely be tuned during the initial startup process as part of commissioning. For facilities with a large number of small units, completion of tune-ups on a biennial basis can quickly become a logistics issue, due to the need to schedule periods where the boilers and process heaters can be shutdown and tuned without undue disruption to the operation of the facility. For such small boilers and process heaters, we believe that a reduction in the tune-up frequency from every two years to every 5 years is appropriate, as emissions from these boilers and process heaters are small, and allowing a

reduced tuning frequency will reduce the cost of the rule. Therefore, we support these changes, as they minimize burden on small sources with minimal emissions impact.

Response: The EPA thanks the commenter for their support.

Commenter Name: Vickie Woods

Commenter Affiliation: Division of Air Quality, North Carolina Department of Environment and Natural Resources (NCDENR)

Document Control Number: EPA-HQ-OAR-2002-0058-3663-A2

Comment Excerpt Number: 19

Comment: Small and gas-fired units. EPA is proposing to change requirement for natural gas-, refinery gas, other clean gas (meeting fuel specification) and light liquid-fired units equal to or < 5 MMBtu/hr to tune-up once every 5 years, with initial tune-up required by compliance date and subsequent tune-ups required at intervals no > 5 years from previous tune-up.

NC DAQ supports this change to the requirements for tune up of clean gas fired and light liquid fired small boilers to once every 5 years after the initial tune-up. NC DAQ agrees that these boilers have smaller potential for emissions issues given their fuel characteristics and use.

Response: The EPA thanks the commenter for their support.

Commenter Name: Robin Mills Ridgway

Commenter Affiliation: Purdue University

Document Control Number: EPA-HQ-OAR-2002-0058-3668-A2

Comment Excerpt Number: 8

Comment: EPA has proposed to change the frequency for tune-ups (following the initial tune-up) for gas and light liquid boilers and process heaters that are equal to or less than 5 MMBTU/hr from every two years to a tune-up once every 5 years following the initial tuneup (76 FR 80614; §63.7500(d) and Table 3(1)). For new units, EPA has proposed to remove the requirement for the initial tune-up, considering that new units will likely be tuned during the initial startup process as part of commissioning. For facilities with a large number of small units, such as the 95 small units at Purdue University's West Lafayette campus, completion of tune-ups on a biennial basis can quickly become a logistics issue, due to the need to schedule periods where the boilers can be tuned without undue disruption to the operation of the facility. Purdue believes that a tune-up every 5 years is appropriate for natural gas boilers and heaters 5 MMBTU/hr or less in size, as emissions from these boilers are small, and allowing a reduced tuning frequency will reduce the implementation cost of the rule. Therefore, Purdue support these changes, as they minimize the compliance burden for small units with minimal emissions impact.

Response: The EPA thanks the commenter for their support.

Commenter Name: Pamela Lacey

Commenter Affiliation: American Gas Association (AGA)

Document Control Number: EPA-HQ-OAR-2002-0058-3672-A2

Comment Excerpt Number: 2

Comment: We agree with your proposal to vary the frequency of these tune-ups with the size of the unit. Large boilers and process heaters with a heat input capacity of 10 million Btu per hour (MMBtu/hr) or greater that are fired with natural gas would be subject to annual tune-ups, whereas those between 5 and 10 MMBtu would be tuned up every two years. We appreciate your proposal to extend the tune-up frequency for very small units with heat input capacity of 5 MMBtu/hr or less from biennial to every 5 years. The agency accepted comments demonstrating that it is logistically burdensome to conduct biennial tune-ups because a single institution may have several hundred of these smaller units. To reduce this burden, EPA proposes to require these smaller units to have a tune-up by the rule's compliance date and then at intervals up to 5 years thereafter. See 76 Fed. Reg. at 80614. AGA supports this common sense proposal.

Response: The EPA thanks the commenter for their support.

Commenter Name: Douglas A. McWilliams

Commenter Affiliation: American Municipal Power

Document Control Number: EPA-HQ-OAR-2002-0058-3685-A2

Comment Excerpt Number: 46

Comment: AMP Supports a 5-year Tune-up Frequency for Gas- and Light Liquid-fired Units Less Than or Equal to 5 mmBtu/hr

EPA proposed changing the frequency for tune-ups (following the initial tune-up) for gas and light liquid boilers that are equal to or less than 5 MMBtu/hr to a tune-up once every five years. This tune-up frequency is appropriate for these units. Municipal utilities that operate these small units do so to provide supplemental power and heating when the main boilers are not operating. Operation of these units may be infrequent, and a biennial testing requirement may force these units to operate more often than necessary simply to comply with the tune-up requirement. This would cause an increase in emissions that would not occur but for the Boiler MACT tuning requirement. Furthermore, emissions from these boilers are small, and allowing a reduced tuning frequency will minimize the compliance burden for small units with minimal emissions impact. AMP supports the five-year tune-up frequency for these units.

Response: The EPA thanks the commenter for their support.

Commenter Name: Heather Parent

Commenter Affiliation: Maine Department of Environmental Protection

Document Control Number: EPA-HQ-OAR-2002-0058-3691-A2

Comment Excerpt Number: 14

Comment: Maine DEP supports the extended time allowed between tune-ups for gas and light liquid-fired units that are ≤ 5 MMBtu/hr.

Response: The EPA thanks the commenter for their support.

Commenter Name: William C. Herz
Commenter Affiliation: The Fertilizer Institute (TFI)
Document Control Number: EPA-HQ-OAR-2002-0058-3448-A1
Comment Excerpt Number: 12

Comment: If EPA is not willing to provide a categorical exemption, TFI would like to make the following comment. In the Proposed Rule, EPA added a requirement for natural gas and certain other units that are less than or equal to 5 MMBtu/hr to conduct a required tune-up at least once every five years.¹⁸ TFI requests that EPA add units that have a federally enforceable operating limit of less than or equal to 100 hrs/yr to this five-year tune-up requirement. EPA has previously used the 100 hrs/yr threshold for defining a limited-use unit in its Reciprocating Internal Combustion Engine rule at 40 C.F.R. § 63.6675.

Response: Units that have a federally enforceable operating limit of less than or equal to 100 hrs/yr would meet the definition of "Limited-use boiler or process heater" in the final amended rule and final amended rule has been revised to require a tune-up for limited-use units once every 5 years.

Commenter Name: Lenny Dupuis
Commenter Affiliation: Dominion Resources Services, Inc.
Document Control Number: EPA-HQ-OAR-2002-0058-3486-A1
Comment Excerpt Number: 7

Comment: EPA should also apply more flexible work practice standards to limited use units, including oil-fired auxiliary boilers (regardless of size). The requirement for these units to perform annual tune-ups (if greater than or equal to 10 mmBtu/hr) is excessive since these units operate so infrequently. EPA should decrease the required frequency of tune-ups from annual to every 5 years. In the alternative, or at a minimum, EPA should apply the same triennial cycle (tune-ups every 3 years) that is established for limited use oil units in the final Utility MATS rule for oil-fired auxiliary boilers.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3448-A1, excerpt 12.

Commenter Name: Eric Guelker, Alliant Energy Corporate Services, Inc.
Commenter Affiliation: Interstate Power and Light Company (IPL) and Wisconsin Power and Light Company (WPL), Alliant Energy Corp.
Document Control Number: EPA-HQ-OAR-2002-0058-3492-A1
Comment Excerpt Number: 11

Comment: Alliant Energy recommends that the biennial tune-up requirement should be revised to every five years. This frequency is more appropriate given the very low utilization of limited use units and also eliminates costly testing, especially given that there may be periods with one or more years of no operation.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3448-A1, excerpt 12.

Commenter Name: Russell A. Wozniak
Commenter Affiliation: The Dow Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3449-A1
Comment Excerpt Number: 7

Comment: EPA should consider modifications to the tune-up provisions for process heaters that operate on a very limited basis. The proposed rule has a new provision that allows a very small process heater (< 5 MMBTU/Hr) to conduct a tune-up every five years. However, implementation of all of the tune-up requirements for process heaters that are operated on a very limited basis remains problematic due to the few hours per year that some of these devices operate. In some cases, small start-up heaters run for about one hour at a time and they typically only run 5 or 6 times a year and at random times on an as needed and often unplanned basis. They are only and can only be used during start up of the process to pre-heat a process material prior to the reactor coming on line and this has a very limited maximum time and cannot be false loaded or extended. Thus, the act of optimizing the system to reduce CO emissions and conducting CO emission screening before and after the adjustments is not possible during the short timeframe when the process heater is operating.

At a minimum, the tune-up requirements in 63.7540(a)(10) need to be modified for this isolated case of a very limited use process heater. The only elements of the work practice that can be executed for these very limited use process heaters are 63.7540(a)(10)(i) and (ii) regarding burner inspections and flame pattern inspections. There simply isn't sufficient operating time to measure CO concentration before and after burner adjustments since the device only runs for ~ 1 hour at a time.

Response: We understand the concern with units that are only used for starting up a large utility boiler or a industrial process and operated for only a few hours at a time. We believe that all units should be properly operated and maintained. A tune-up helps to ensure that a unit is properly operated and maintained. We proposed a five year schedule for tuning a limited-use unit because they operate infrequently. We continue to believe this is appropriate for limited-use units. In addition, measurements of CO and oxygen as part of the tune-up requirement are not required to be taken as required for a performance stack test, but may be taken using a portable hand-held CO/oxygen analyzer.

Commenter Name: Shannon S. Broome
Commenter Affiliation: Auto Industry Forum (AIF)
Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1
Comment Excerpt Number: 41

Comment: A final, related, technical issue for comment is that EPA states in the preamble that it is changing the tune-up frequency for units that are *equal to or less than* 5 MMBtu/hr, the proposed regulatory language applies only to units *less than* 5 MMBtu/hr. EPA should revise the final regulatory language to reflect the change to the tune-up frequency for those units as stated in the preamble.

Response: Table 3 of the final rule has been revised to be consistent with EPA's intent, as explained in the preamble to the proposed rule.

Commenter Name: Lenny Dupuis
Commenter Affiliation: Dominion Resources Services, Inc.
Document Control Number: EPA-HQ-OAR-2002-0058-3486-A1
Comment Excerpt Number: 6

Comment: We support the more flexible work practice provisions in the revised proposal that would change the cycle of required unit tune-ups from every 2 years to every 5 years for small boilers and process heaters. However, EPA proposes to apply this more flexible provision only for units under 5 mmBtu/hr. Since a 110 mmBtu/hr threshold has been used throughout this rule to distinguish between small and large sources and define certain subcategories, EPA should extend these provisions to all units below 10 mmBtu/hr so that all units within a defined subcategory at a given facility are subject to the same work practice standards and subject to the same frequency/cycle of scheduled tune-up requirements.

Response: The EPA thanks the commenter for their support but we disagree that the threshold should be raised to 10 million Btu per hour for conducting a tune-up every 5 years. The commenter provides no explanation or information to support its recommendation that the threshold should be changed.

Commenter Name: Mary Sullivan Douglas
Commenter Affiliation: National Association of Clean Air Agencies (NACAA)
Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1
Comment Excerpt Number: 47

Comment: NACAA recommends that the frequency of mandated tune ups be based on objective data concerning decay of performance after a tune up.

Response: The requirement to conduct an annual tune-up, or at other frequencies, to demonstrate compliance with the work practice is based on information available to the agency showing the increase in fuel use each year that the boiler is not serviced (tuned). The frequencies established are based on duty cycle (year round operation vs. limited use operation) and to provide ease of scheduling the required tune-up for facilities that have numerous small boilers and process heaters. In addition, the rationale for establishing the work practice of the tune-up instead of emission limits was that measuring emissions was impractical due to technical and economic limitations. The commenter did not provide an explanation or information to support its recommendation.

Commenter Name: Bart Sponsellar
Commenter Affiliation: Wisconsin Department of Natural Resources
Document Control Number: EPA-HQ-OAR-2002-0058-3527-A2
Comment Excerpt Number: 22

Comment: EPA is proposing that small gas and oil fired sources smaller than 5 mmbtu/hr be required to perform tune-ups once every 5 years. Petitioners originally requested EPA to consider reducing the tune-up frequency for boilers smaller than 10 mmbtu/hr or which are limited use.

The Department supports reducing the tune-up frequency for boilers smaller than 5 mmbtu/hr. We believe the majority of these units operate at a single setting or over a small load range which reduces the likelihood for combustion conditions to vary over time. On this basis, Department believes EPA should consider reducing the tune-up frequency for larger units which also operate at a single or preset level. Such units may include metal treating furnaces or annealing processes and small biomass boilers. The operators of these sources can self identify under a final rule and therefore no additional analysis of source categories is required by EPA. Another option is to allow sources smaller than 10 mmbtu/hr to extend tune-ups to every 4 years if combustion settings did not vary between the biennial tune-ups. Lastly, EPA can allow any source with a continuous O₂ and CO trim system to perform tune-ups every four years. Sources with this type of system are essentially performing tuning on a continuous basis. A four year schedule coincides with required inspection of the mechanical system and burners.

Response: We agree that units with oxygen trim systems that maintain optimum air/fuel ratio may not benefit from annual tune-ups because these systems trigger boiler adjustments on an as needed basis. 63.7540(a)(12) of the final rule has been revised to required units with these types of combustion control systems to conduct a tune-up on a less frequent basis (i.e., once every 5 years).

Commenter Name: Bart Sponsellar

Commenter Affiliation: Wisconsin Department of Natural Resources

Document Control Number: EPA-HQ-OAR-2002-0058-3527-A2

Comment Excerpt Number: 28

Comment: This proposed schedule for CO, PM, and tune-ups is premised on the CO/O₂ trim system and a two year stack test schedule. A three or four year tune-up and stack test schedule could be considered for sources which implement a neural network system in operating the boiler system. This approach is adopted under in the finalized EGU MACT rule. The default requirement is for EGU boilers to undergo tune-ups every 36 months or 3 years. However the rule allows EGU sources with a neural network system in place to perform tune-ups on a four year cycle. To put a neural network system in place a source is typically tested intensively with computer fluidized modeling performed to determine optimum conditions for operating the boiler. The Department feels that a source which is optimized and operated to this level can be placed on a three or four year stack test schedule at a minimum for PM and CO emissions and for tune-ups.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3527-A2, excerpt 22.

Commenter Name: Bart Sponsellar

Commenter Affiliation: Wisconsin Department of Natural Resources

Document Control Number: EPA-HQ-OAR-2002-0058-3527-A2

Comment Excerpt Number: 23

Comment: In addressing limited-use units, the Department suggest that these units perform tune-ups based on operating hours which coincides to the primary tune-up schedule for that type of source: annual, biennial, five years. In fact, any source should be allowed the option to track operating hours and perform tune-ups accordingly. This approach could also be used by EPA to

streamline or eliminate the need for distinguishing limited use or seasonal sources or the need to have a separate requirement and time constraints in place for the start-up and shutdown work practices.

Response: We thank the commenter for their suggestion. However, units that chose to exercise such an option would need to record and report hours of operation to determine tune-up frequency, which would likely complicate the compliance and enforcement because different units at a particular facility could be on different tune-up schedules.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 46

Comment: We support the proposed reduced frequency of tune-up requirements for small boilers and process heaters but believe there is no justification for requiring tune-ups at all for BPH firing gas 1 or for BPH with a design heat input capacity of 10 MMBTU/hr firing other fuels and a simple design requirement or an Operations and Maintenance Plan work practice is more reasonable.

EPA is proposing to change the existing BPH NESHAP to allow BPH firing gas or light liquid fuels with a design heat input of <5 MMBTU/hr to tune-up once every 5 years, rather than annually or biennially, with an initial tune up required by the compliance date. The potential emission reductions from tune-ups on such small emission sources (and even large gas 1 BPH) is so insignificant that tune-ups are not justified at all. In the aggregate tune-ups for such units are extremely costly and it is arbitrary and capricious to impose these costs and the associated burdens for no benefit. On page 80614 of the preamble EPA cites the fact that one institution has 700 sources of less than 5 MMBTU/hr. While we believe EPA has underestimated the costs for these tune-ups, using EPA's estimate of \$5000 per unit initially and \$1000 for each later tune-up, means this one institution will incur at least \$3.5 million in initial tune-up costs and \$700,000 in additional costs every five years. The required permitting, recordkeeping and reporting associated with these tune-ups will add cost and burdens to the out-of-pocket costs. EPA fails to quantify organic HAP or metal HAP emissions in the rulemaking record from any of the sources subject to tune-up requirements. Rather it estimates VOC and PM emissions, of which these HAP categories are a small portion. Even then, in Table 4 of the preamble, EPA only estimates 118 Tons of PM and 85 Tons of VOC will be reduced from the 11,911 gas 1 units subject to the tune-up requirements. That is less than 20 pounds per year PM and less than 15 lb per year VOC per gas 1 BPH. EPA does not indicate the average firing for gas 1 BPH, but units below 5 MMBTU/hr are likely well below average, so the potential emission reductions from them are even smaller. Thus, EPA's own estimates indicate that for \$2,875 per year this requirement reduces, at the most, a few pounds of HAP per BPH and even smaller quantities from BPH firing less than 5 MMBTU/hr. Even assuming 5 lb per year of HAP emissions per BPH, just this tune-up requirement represents over \$1 million per ton of HAP reduction. Since there are negligible emission reductions associated with these tune-ups and thus negligible, if any, health benefits to claim, a unsubstantiated 1% fuel savings is arbitrarily assumed to justify the tune-up costs. However, even if true, the CAA is an air emission law and section 112 is devoted to reducing

HAPs and thus the Agency is not authorized to impose requirements for the purpose of reducing energy usage. Since the potential emissions reductions from small BPH are essentially insignificant, all of this cost and burden is wasted and thus should not be imposed.

Instead of the proposed five year tune-up for gas 2 units under 5 MMBTU/hr and the tune-up requirements for any gas 1-fired BPH, EPA should only impose a design requirement that documents that the unit is designed for firing gas 1 fuel. For less than 10 MMBTU/hr BPH firing other fuels, an Operations and Maintenance Plan work practice, such as incorporated into the Engine NESHAP should be required. Item 9 of Table 6 of part 63 subpart ZZZZ addresses the parallel situation for small and limited use engines. It requires that the owner/operator follow a work practice and demonstrate continuous compliance by “(i) Operating and maintaining the stationary RICE according to the manufacturer's emission-related operation and maintenance instructions; or (ii) Develop and follow your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.”

Response: We disagree with the comment that EPA should only impose a design requirement, instead of the work practice of a tune-up, for units burning Gas 1 fuel. First, EPA disagrees with the commenters characterization of the Agency’s authority under the Clean Air Act. When establishing work practice standards, EPA must ensure that the standard represents the maximum achievable control technology, and cannot take cost into account when determining that level of emission reduction. Further, the commenter is incorrect that EPA’s work practice requirement for Gas 1 units is based on reducing energy usage. Rather, the tune-up requirement is intended to reduce HAP emissions from units subject to the requirement, as explained in the preamble to the March 2011 final rule.

The commenter suggests that, for boilers and process heaters firing other than Gas 1 fuels, the design requirement should be similar to item 9 of table 6 of subpart ZZZZ. The requirements in item 9 of table 6 of ZZZZ are to operate and maintain the engine according to the manufacturer's emission-related operation and maintenance instructions, which is analogous to tuning/optimizing the boiler emissions to manufacturer's specifications. Also, ZZZZ requires inspection of certain engine equipment which is similar to what is required under the boiler tune-up with requirements on a more frequent basis that every 5 years. Therefore, for boilers and process heaters firing other than Gas 1 fuels, there is no practical difference between the requirements in each rule.

8C. New Source Tune-up Compliance Date

Commenter Name: Bruce W. Ramme

Commenter Affiliation: Wisconsin Electric Power Company (WE Energies)

Document Control Number: EPA-HQ-OAR-2002-0058-3452-A1

Comment Excerpt Number: 5

Comment: We Energies supports EPA’s proposal to require the initial tune-up for a new unit to be performed within one year of startup. This should provide a sufficient amount of time for the boiler operator to learn how to most efficiently operate a new boiler prior to performing the boiler tune-up.

Response: The EPA thanks the commenter for their support.

Commenter Name: Jessica Bridges

Commenter Affiliation: United States Clean Heat & Power Association (USCHPA)

Document Control Number: EPA-HQ-OAR-2002-0058-3501-A1

Comment Excerpt Number: 11

Comment: It is appropriate that EPA recognize that initial tune-ups at new sources generally occur as part of installation and that the initial tune-up after installation can take advantage of the learning curve in efficiently operating new units. Therefore having the initial tune-up within one year after start up provides appropriate opportunity to improve efficiency based upon experience.

Response: The EPA thanks the commenter for their support.

Commenter Name: Michael L. Krancer

Commenter Affiliation: Pennsylvania Department of Environmental Protection (DEP)

Document Control Number: EPA-HQ-OAR-2002-0058-3507-A1

Comment Excerpt Number: 16

Comment: The EPA has proposed that the initial tune-up after startup of a new unit must be completed within one year of startup.

The DEP agrees with this approach for new sources because the units are well tuned as part of the installation.

Response: The EPA thanks the commenter for their support.

Commenter Name: Shannon S. Broome

Commenter Affiliation: Auto Industry Forum (AIF)

Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1

Comment Excerpt Number: 53

Comment: EPA Should Amend Its Proposal to Base the Time Period for Completion of the First Tune-Up After Installation on the Tune-Up Cycle Germane to the Specific Unit.

Based on the request of petitioners that EPA clarify the timing of tune-ups with respect to the compliance dates for new sources, EPA proposes to require completion of the initial tune-up after startup within one year of startup. *See id.* at 80,614. EPA makes this proposal based on its recognition that, generally, units are tuned as part of installation. *See id.*

In the experience of AIF's members, EPA is correct in recognizing that, generally, units are tuned as part of the installation process. Accordingly, AIF supports EPA's proposal in principle, however, EPA should amend it to make the deadline for the first tune-up after installation consistent with the tune-up cycle germane to the specific unit. For example, under the proposed reconsideration rule, units such those fired by NG, RG, other clean gas like LFG (that meets the "other Gas 1 fuel" specification) and light liquid operate on a five-year tune-up cycle. *See id.* Consistent with that requirement, EPA should amend the proposal to require units fitting within

that classification that are located at new sources to complete their initial tune-up after installation within five years of startup—as opposed to within one year after startup under the reconsideration proposal. As EPA correctly acknowledges that, generally, units are tuned as part of installation, it would be arbitrary and capricious for EPA to require a unit to conduct its initial tune-up after installation on a different timetable than the cycle otherwise germane to that specific type of unit. Therefore, while AIF supports the principle underlying EPA’s proposal, it recommends that EPA finalize the proposal with the suggested amendment that would key the initial tune-up requirement to the tune-up cycle that is germane to the specific unit.

Response: We agree with the commenter that for new units their first tune-up should be on the same cycle from startup as required after the initial tune-up. 63.7510(g) in the final rule has been revised to key the initial tune-up to the tune-up cycle that is germane to the specific unit. The reason being is that new units on initial start-up are tune-up/adjusted to manufacturer's specifications.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 14

Comment: We support EPA’s proposal to allow 365 days from startup for new/reconstructed sources subject to a tune-up requirement to complete the initial tune-up.

1. It takes time for a new BPH to shakedown and for an owner/operator to learn how to most efficiently operate a new or reconstructed unit. Allowing a year for the initial tune-up, will accommodate this learning curve, allow the BPH to reach a normal operating mode and to make any needed equipment modifications, and, thereby, foster good air pollution control.

2. The one year compliance time for the initial tune-up for a new or reconstructed BPH is contained in the second sentence of proposed §63.7510(g). However, the language imposes a retroactive requirement on a new or reconstructed BPH that started up before the effective date of the final rule (i.e., that it was tuned up within a year after startup). Thus, we recommend §63.7510(g) be revised to eliminate the retroactivity as follows:

For new or reconstructed affected sources, you must demonstrate initial compliance with the applicable work practice standards in Table 3 to this subpart no later than the compliance date that is specified in § 63.74595 and according to the applicable provisions in § 63.7(a)(2). You must conduct the initial tune-up within 365 days after the initial compliance date specified in §63.7495(a) of this subpart startup of the source. Thereafter, you are required to complete the applicable annual, biennial, or 5-year tune-up as specified in § 63.7540(a).

Response: See the response to comment EPA-HQ-OAR-2002-0058-3512-A1, excerpt 53. 63.7510(g) has also been revised to clarify the initial compliance date for new units that started up prior to the promulgation of the final rule.

8Z. Out of Scope - Work Practices

Commenter Name: Felix Mestey, on behalf of Donald R. Schregardus

Commenter Affiliation: Clean Air Act Services Steering Committee, Department of Defense (DoD)

Document Control Number: EPA-HQ-OAR-2002-0058-3427

Comment Excerpt Number: 16

Comment: DoD also supports EPA's decision to retain the biennial tune-up frequency requirement for Gas 1 boilers rated between 5 and 10 MMBtu/hr heat input;

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Felix Mestey, on behalf of Donald R. Schregardus

Commenter Affiliation: Clean Air Act Services Steering Committee, Department of Defense (DoD)

Document Control Number: EPA-HQ-OAR-2002-0058-3427

Comment Excerpt Number: 17

Comment: DoD also supports EPA's decision to retain the tune-up delay provision in §63.7540(a)(13) that if a unit is not operating on the required date for a tune-up, the tune-up must be conducted within one week of startup.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Lenny Dupuis

Commenter Affiliation: Dominion Resources Services, Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3486-A1

Comment Excerpt Number: 14

Comment: While reasonable limits for PM are appropriate, EPA should establish alternative good combustion practice and tune-up requirements for other HAPs for biomass units, just as it has proposed for units that combust natural gas. In justifying its decision to apply work practice standards in place of emission limits for gas boilers and process heaters, EPA cites a potential cost of over \$14 billion for installing controls to meet such limits. EPA further notes that control requirements would provide a disincentive for fuel switching to gas as a control option for other fuel subcategories, and could even encourage some facilities to switch from gas to a cheaper fuel such as coal.³ This rationale could also apply to biomass boilers and therefore provides ample support for adopting work practice standards in lieu of emission limits for boilers that burn biomass. This approach would also provide the opportunity for more time to re-evaluate both the need and the feasibility of emission limits for biomass units during the next MACT review cycle from what should be a more robust data base as this fuel option continues to be added to the fleet of existing electric generation systems.

[Footnote]

(3) 75 Fed. Reg. 32025

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 6

Comment: We recommend that once EPA has determined the quantitation limits of different reference methods, it should compare its boiler emission data to determine whether or not there were any sources with emissions above the reference method quantitation limits. If the majority of source emissions are below the reference method quantitation limits, a work practice standard in lieu of a numeric emission standard is appropriate as MACT, since sources will not be able to accurately measure emissions against any numerical standard.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

101A. Emissions Standards for Gas 1 Units [DENIED PETITIONER ISSUE]

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 40

Comment: In its 2011 final rule EPA proposed a new rationale for its use of work practice standards for the "Gas 1" subcategory. It notes that "the measured emissions from these units are routinely below the detection limits of EPA test methods," and concludes therefrom that it is "impracticable to reliably measure emissions from these units." 76 Fed. Reg. at 15,638. This decision is unlawful and arbitrary for the reasons given in the 2010 Comments, which are incorporated by reference as if set forth fully herein, and above with respect to EPA's work practice standards for dioxins.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 45

Comment: EPA's work practice standards for Gas 1 units, Gas 2 units, smaller units, and periods of startup and shutdown are unlawful and arbitrary. EPA has not shown that any of these standards are consistent with § 112(d) in the sense of reflecting measures that reflect either the maximum achievable degree of reduction in emissions (as required by § 112(d)(2)) or the

performance of the relevant best performing units (§ 112(d)(3)). In particular, EPA's work practice standards for Gas 1, Gas 2, and smaller units are merely tune up requirements and do not purport to reflect with the maximum degree of reduction that is achievable for these units or the best units' performance.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 4

Comment: HAP emissions from gas-fired boilers and process heaters are extremely low and cannot be reliably measured at these low levels due to deficiencies in both laboratory analysis methods and stack sampling methods.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 5

Comment: Detection limits reported in the test reports received by EPA during the Boiler MACT data collection efforts varied greatly, pointing to the lack of repeatability of measurements at these very low levels. No emission standard should be set below the quantitation limit of the test method used to demonstrate compliance with the standard.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 7

Comment: Good combustion practices and periodic tune-ups as work practices will ensure proper operation of gas-fired units and continuous minimization of emissions. In fact, for gas-fired sources, these types of practices serve as MACT currently for minimizing organic HAP emissions.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Paul Noe
Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.
Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1
Comment Excerpt Number: 8

Comment: EPA should also recognize that many gas-fired boilers and process heaters do not have vents or stacks to which EPA measurement methods can be applied, and to significantly modify the stacks would be technically infeasible in some applications and would be economically infeasible in many others.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Paul Noe
Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.
Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1
Comment Excerpt Number: 9

Comment: Measurement infeasibility and control cost issues serve to justify the technical and economic feasibility criteria under §112(h) for requiring work practices in lieu of numeric emission standards.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Mary Sullivan Douglas
Commenter Affiliation: National Association of Clean Air Agencies (NACAA)
Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1
Comment Excerpt Number: 29

Comment: EPA’s assertion that CO monitoring is infeasible is inconsistent with its proposed reliance on CO optimization for D/F control.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Richard Krock
Commenter Affiliation: The Vinyl Institute
Document Control Number: EPA-HQ-OAR-2002-0058-3526-A1
Comment Excerpt Number: 4

Comment: Work Practice Standards Are Appropriate Emission Controls for Gas 1 Units

The principles that warrant the use of work practice standards for dioxin emissions also apply to emissions from natural gas and refinery gas (“Gas 1”) fired units, which utilize clean burning fuels. As noted above, an emission standard is “not feasible” when “the application of

measurement technology to a particular class of sources is not practicable due to technological and economic limitations.”¹¹ VI members, as well as other industries, face exactly this problem in measuring hazardous air pollutant (HAP) emissions from Gas 1 fuels.

Natural gas and refinery gas are among the cleanest burning fossil fuels and HAP emissions associated with the combustion of these gases are minute and therefore extremely difficult to measure because the levels at which they are present are far below the levels that can be accurately measured using existing analytical methods. Further, at an EPA-estimated cost of \$14 billion, emission controls for Gas 1 units would be catastrophically expensive to the point of being economic impracticable.¹² Further, such controls would provide a disincentive for facilities to switch from “dirtier,” cheaper fuels to cleaner natural gas, and would result in a net HAP emissions increase in the long term. Creating this disincentive would, in EPA’s words, “be inconsistent with the emissions reductions goals of the CAA, and of section 112 in particular.”¹³ Therefore, work practice standards are appropriate under the Act for these units.

[Footnotes]

(11) 42 U.S.C. § 7412(h)(2)(B).

(12) *National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters; Proposed Rule*, 75 Fed. Reg. 32,006, 32,025 (June 4, 2010).

(13) 75 Fed. Reg. 32,025.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 4

Comment: EPA could ease the cost burden of the major source proposal, by simply adopting a design standard for gas fired equipment: equipment designed to fire gas is subject to only recordkeeping requirements that they meet the design standard. EPA chose such a path in the recent review and final rule for Marine Loading Operations by referencing a Coast Guard design standard. If EPA chooses not to utilize a design standard approach it should provide a transparent analysis on why that was not the most cost-effective option available.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Janice E. Nolen

Commenter Affiliation: American Lung Association

Document Control Number: EPA-HQ-OAR-2002-0058-3679-A2

Comment Excerpt Number: 10

Comment: In the prior final rule issued March 21, 2011, and in this proposed rule, the EPA argues against measuring emissions in these boilers from the stacks and justifies the use of work practice standards as the only remaining option. Even if the EPA could demonstrate that the Agency could not set emission standards for boilers, the Agency misses the opportunity to take one of the other options available under Section 112(h): that is, to “promulgate a design, equipment,” or “operational standard” that might ensure that these toxic emissions are reduced. Requiring the adoption of equipment that is in use in the lowest emitting facilities would be much more likely to reduce exposure than just ordering a periodic “tune up.” Instead, the EPA argues that “tuned up” boilers will suffice to address toxic emissions from 195,000 boilers (EPA, 2011d). We support fully encouraging plants to follow the manufacturer’s instructions for preventing emissions from getting worse, but that is not the same as reducing already harmful emissions. Unfortunately, the proposed rule does not seek to improve work practice standards or to assess whether they effectively reduce toxic air emissions from those facilities. It is hard to imagine that emissions standards cannot be successfully incorporated that would actually reduce emissions from one in eight boilers.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: David L. Meeker

Commenter Affiliation: National Renderers Association (NRA)

Document Control Number: EPA-HQ-OAR-2002-0058-3476-A1

Comment Excerpt Number: 13

Comment: EPA has the statutory authority as identified in Section 112(h) of the CAA to prescribe the type of compliance demonstration required to be met to control HAP emissions under the Boiler MACT and other NESHAP regulations.

(h) WORK PRACTICE STANDARDS AND OTHER REQUIREMENTS.—(1) IN GENERAL.—For purposes of this section, if it is not feasible in the judgment of the Administrator to prescribe or enforce an emission standard for control of a hazardous air pollutant or pollutants, the Administrator may, in lieu thereof, promulgate a design, equipment, work practice, or operational standard, or combination thereof, which in the Administrator’s judgment is consistent with the provisions of subsection (d) or (f). In the event the Administrator promulgates a design or equipment standard under this subsection, the Administrator shall include as part of such standard such requirements as will assure the proper operation and maintenance of any such element of design or equipment.

(2) DEFINITION.—For the purpose of this subsection, the phrase “not feasible to prescribe or enforce an emission standard” means any situation in which the Administrator determines that—

(A) a hazardous air pollutant or pollutants cannot be emitted through a conveyance designed and constructed to emit or capture such pollutant, or that any requirement for, or use of, such a conveyance would be inconsistent with any Federal, State or local law, or

(B) the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations.

A work practice standard can be used for compliance demonstration when it is "not feasible to prescribe or enforce an emission standard" due to technological and economic limitations for a specific subcategory of emission sources. For NESHAP Subpart DDDDD, EPA determined that work practice standards are appropriate for ensuring HAP emissions are effectively controlled from Gas 1 units.

The information provided in this comment letter for processed fats HAP content is analogous to the data used by EPA to determine Gas 1 units are not required to meet a MACT Floor, and instead demonstrate control of HAP emissions for Gas 1 units by enforcing work practice standards. The NRA feels that the non-detect analysis data identified for the metal HAP content in processed fats samples indicates the infeasibility for establishing a MACT Floor for the requested separate subcategory (unit designed to burn processed fats subcategory). Processed fats are essentially an "equivalent fuel" to Gas 1 regarding metal HAP, acid gas HAP, and organic HAP content, based on the defined thresholds established by EPA. Furthermore, the processed fats-fired boilers can meet the current explanations identified by EPA for requiring work practice standards for Gas 1 units to demonstrate compliance with the Boiler MACT.

"If your unit combusts only natural gas, refinery gas, or equivalent fuel (other gas that qualifies as Gas 1 fuel), with limited exceptions for gas curtailment and emergencies, your unit is subject to a work practice standard that requires an annual tune-up in lieu of emission limits." [76 FR 15612]

The NRA feels the control of HAP emissions from processed fats-fired boilers will be accomplished most cost effectively by work practice standards developed for the requested separate subcategory. Due to the similar HAP emissions as identified in this comments letter for processed fats-fired boilers and Gas 1 units, the NRA requests similar work practice standards compliance requirements for the requested separate processed fats subcategory. Specifically, the NRA requests that processed fats-fired boilers are subject to the following work practice standards included in Table 3 to NESHAP Subpart DDDDD.

- A facility with a new or existing boiler with heat input capacity greater than 10 MMBtu/hr must conduct a tune-up of the boiler annually in accordance with §63.7540.
- A facility with an existing boiler must complete a one-time energy assessment performed by a qualified energy assessor.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Mary Sullivan Douglas

Commenter Affiliation: National Association of Clean Air Agencies (NACAA)

Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1

Comment Excerpt Number: 28

Comment: In 2004, EPA candidly admitted that it could not develop CO work practice standards for ICI Boilers:

Consequently, any uniform requirements or set of work practices that would meaningfully reflect the use of good combustion practices or that could be meaningfully implemented across any subcategory of boilers and process heaters could not be identified.²⁹

EPA has nonetheless asserted that measuring CO levels is impracticable³⁰ and has set out what it describes as a work-practice standard. What EPA has adopted and continues to propose is not a set of good combustion practices that could be meaningfully implemented across a subcategory, but a requirement to follow the manufacturer's recommendation for good combustion practices. This assumes that manufacturers can do what EPA could not – identify a set of good combustion practices applicable to boilers designed and built over the past 50 years. It also assumes that the manufacturers of these units are still in business and will invest the resources needed to do so voluntarily. These assumptions are patently incorrect. There is no obligation on the part of manufacturers to develop any meaningful set of broadly applicable good combustion practices or to determine the set of work practices employed by the best performers in the sector or to determine whether any particular set of work practices approximates the emission performance of the best performers in a subcategory. Conceivably, an organization like The National Board of Boiler & Pressure Vessel Inspectors might be able to provide a certification/best practices review of any legacy boiler, even if the original manufacturer is no longer in business and individual sources can retain consulting firms to study the operation of individual boilers and recommend a set of best practices for that boiler. We submit that such a program, that imposes obligations on relatively clean boilers as well as high emitters, if conducted in a technically sound manner, may prove to be more costly overall and provide far less environmental benefit than a defined numerical limit that requires significant emission reductions from gross emitters. CO CEMs are available, relatively inexpensive and used by industry for process control. These devices should be required for all combustion units covered by the major source and CISWI rules.

[Footnotes]

(29) Memorandum, Eddinger, J., USEPA to Docket No. OAR-2002-0058, February, 2004, "Revised MACT Floor Analysis for the Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants Based on Public Comments" p.18.

(30) NACAA has commented that this representation is incorrect. CO emissions' testing has been conducted for several decades on thousands of different sources.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 96

Comment: EPA acknowledges that the cost of testing small boilers and process heaters is prohibitive. While the cost of emissions testing larger units is less prohibitive, EPA must consider these costs when establishing the frequency of testing.

The benefits of testing more frequently than every 5 years do not justify the costs. HAP emissions change only when operating parameters change (e.g., firing rate, maximum contaminant input limits for chloride and mercury, type of fuel, combustion efficiency, oxygen content, etc.) or when design changes occur. Absent these changes to an affected source, operating parameters established by implementation of Boiler MACT are more than sufficient to ensure that emissions will not significantly change over time. Furthermore, the Boiler MACT provisions require owners and operators to measure and monitor prescriptive operating limits, as well as monitor, measure, and keep records of each type of fuel on a continuous basis to verify compliance with limits established during the compliance test. The Boiler MACT regulations also stipulate that sources must perform testing under a representative operating load and require sources to maintain within 110% of the average operating load observed during testing. Based on these stringent monitoring requirements, the operating parameters established during testing are sufficient for a source to demonstrate compliance for a 5-year period. Modifications will be tested under the provisions for new and modified sources, and do not need to be considered in ongoing test requirements.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Bruce A. Steiner

Commenter Affiliation: American Coke and Coal Chemical Institute (ACCCI)

Document Control Number: EPA-HQ-OAR-2002-0058-3547-A2

Comment Excerpt Number: 6

Comment: Gas 2 Units Combusting Coke Oven Gas or Other Process Gases Should be Subject to the Same Work Practices as Natural Gas-Fired Units The work practices applicable to Gas 1 units are equally applicable to units that combust coke oven gas and other process gases. To the extent that the best performing units combusting those alternate fuels conduct tune ups (or other similar work practices) to achieve emissions reductions, EPA can promulgate those measures as work practice based emissions standards to ensure continuous reductions in the quantity and/or rate of emissions of air pollutants under §112(d) and §302(k). As such, there is no need to delve into the prerequisites that exist under §112(h) for these units.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Bruce A. Steiner

Commenter Affiliation: American Coke and Coal Chemical Institute (ACCCI)

Document Control Number: EPA-HQ-OAR-2002-0058-3547-A2

Comment Excerpt Number: 7

Comment: Should the agency feel compelled to press forward with its §112(h) analysis, we believe that EPA's findings regarding the infeasibility of controlling and monitoring emissions from natural gas-fired boilers and process heaters are both appropriate and equally applicable to units fired with coke oven gas or other process gases. As found by EPA in its originally proposed Boiler MACT, work practices should supplant numeric emission limits on Gas 1-fired units because “[f]irst, the capital costs estimated for installing controls on these boilers and process

heaters to comply with MACT limits for the five HAP groups is over \$14 billion,” a cost “higher than the estimated combined capital cost for boilers and process heaters in all of the other subcategories.” Second, EPA found that proposing emission standards for gas-fired boilers and process heaters “would have the negative benefit of providing a disincentive for switching to gas as a control technique (and a pollution prevention technique)” and “may have the negative benefit of providing an incentive for a facility to switch from gas (considered a ‘clean’ fuel) to a ‘dirtier’ but cheaper fuel (i.e., coal).” As EPA correctly concluded, “[i]t would be inconsistent with the emissions reductions goals of the CAA, and of §112 in particular, to adopt requirements that would result in an overall increase in HAP emissions.”

These same arguments apply with even greater force to coke oven gas-fired and process gas-fired units. First, the costs of controlling coke oven gas-fired units are similar to the per-unit costs faced by Gas 1 units. Just like Gas 1 units, coke oven gas units, if subjected to Gas 2 requirements, would face the need to install fabric filters for the control of particulate matter (PM) and mercury (Hg), as well as wet scrubbers to control hydrochloric acid (HCl) and an oxidizing catalyst to control carbon monoxide (CO) - all at a cost well beyond that already calculated by EPA. Second, imposing emission standards on these units would clearly incentivize operators to cease burning coke oven gas in preference for the fossil fuels that cost less to burn, resulting in an increase in emissions “inconsistent with the emissions reductions goals of the CAA, and of section 112 in particular.”

But unlike natural gas, which is generally stored as a commodity when not consumed, coke oven gas must be flared as a waste gas to ensure a safe environment if not immediately usable at a facility. As a result, creating incentives which cause operators of coke oven gas-fired units to fuel-switch (even to natural gas) would result in significant net emissions increases. That is because the facility would necessarily combust both the coke oven gas (at a flare) and the additional fossil fuel necessary to generate sufficient heat for its operations. Simply put, any standard that creates a disincentive to recover energy from process gases is bad for the environment and thus contrary to the goals of the CAA. Extending work practice tune-up standards to coke oven gas or process gas-fired boilers will ensure that there is no environmentally detrimental incentive to displace coke oven gas or process gas with natural gas or other fuels in the boiler and flare those recoverable energy sources.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Russell A. Wozniak

Commenter Affiliation: The Dow Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3449-A1

Comment Excerpt Number: 2

Comment: Dow supports EPA’s direction and this proposal to require work practice standards for natural gas, refinery gas, and other gas 1 fuels.

As previously detailed in our August 19, 2010 comments on the proposed rule, Dow supports Other Gas 1 fuels being regulated by work practice standards in the same manner as natural gas and refinery gas for the following reasons:

- The use of petrochemical and chemical plant off-gas streams as fuel is essential to being energy efficient at larger chemical production facilities. These fuels are typically clean fuels with a composition similar to natural gas or refinery gas.
- Imposing strict emission limits, especially for CO, would likely have the undesirable environmental impact of source owner/operators having to operate in a less efficient manner by combusting more fuel which in turn would likely increase emissions of criteria air pollutants and GHG pollution.
- Imposing strict emission limits, especially for CO, would likely complicate NOx emission reduction efforts that may be required for some sources in the future to meet the future 75 ppbv 8-hour ozone NAAQS.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Randall D. Quintrell

Commenter Affiliation: Georgia Paper & Forest Products Association

Document Control Number: EPA-HQ-OAR-2002-0058-3451-A1

Comment Excerpt Number: 17

Comment: We support EPA's proposed use of work practice standards for gas-fired boilers.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Traylor Champion

Commenter Affiliation: Georgia-Pacific LLC (GP)

Document Control Number: EPA-HQ-OAR-2002-0058-3465-A1

Comment Excerpt Number: 1

Comment: GP strongly supports EPA’s retention of the provision in the final rule that subjects boilers and process heaters utilizing clean burning gas fuels (Gas 1) to only a work practice standard under Section 112(h) of the CAA. As EPA has stated in final rule (76 Federal Register 15638); “*EPA has determined that it is not feasible to prescribe numerical emissions standards for Gas 1 units because the application of measurement methodology is not practicable due to technological and economic limitations.*” “*The commenters correctly point out that the measured emissions from these units are routinely below the detection limits of EPA test methods, and, as such, EPA considers it impracticable to reliably measure emissions from these units.*”

For a number of our boilers and process heaters subject to the Boiler MACT requirements, GP is evaluating the option of fuel switching to natural gas as a compliance option if the conversion can be economically justified. If EPA were to require unnecessary controls on Gas 1 sources, the cost of these additional controls would be a disincentive to switching to these cleaner fuels. GP agrees with EPA’s use of a work practice and we believe this option is not only appropriate but the only available means of demonstrating compliance for Gas 1 units due to the impracticality of establishing a numerical limit.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Barry Christensen

Commenter Affiliation: Occidental Chemical Corporation (OCC)

Document Control Number: EPA-HQ-OAR-2002-0058-3477-A1

Comment Excerpt Number: 1

Comment: OCC continues to strongly support the exemption from numerical emission limits for existing gas fired units and the use of the periodic tune-ups as an alternative work practice. Natural gas is the cleanest fossil fuel and HAP emissions associated with the combustion of natural gas are minimal. The environmental and cost reduction benefits of requiring work practices, such as employing good combustion practices, far outweigh any benefits potentially obtainable through emission limitations. For example, periodic tune-ups performed according to established criteria will ensure that combustion systems remain optimized according to manufacturer's recommendations. Furthermore, implementing emission limits instead of work practices for natural gas firing would be catastrophically expensive.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Lenny Dupuis

Commenter Affiliation: Dominion Resources Services, Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3486-A1

Comment Excerpt Number: 4

Comment: We support EPA's decision to retain work practices rather than emission limits for natural gas-fired boilers located at major sources of hazardous air pollutants (HAPs).

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Peter Pagano

Commenter Affiliation: American Iron and Steel Institute (AISI)

Document Control Number: EPA-HQ-OAR-2002-0058-3490-A1

Comment Excerpt Number: 13

Comment: All metal process furnaces (regardless of fuel burned) should be subject to work practices in lieu of numeric criteria. The proposed rule provides work practice standards for the metal process furnaces subcategory. (Table 3 of Subpart DDDDD.) Section 112(h)(1) of the CAA authorizes the promulgation of work practices in lieu of emission limits "if it is not feasible in the judgment of the Administrator to prescribe or enforce an emission standard for control of a hazardous air pollutant or pollutants." EPA properly concluded that emission standards are not feasible for metal process heaters for two reasons. First, imposing emission limitations on these units would be economically impracticable-particularly in contrast to the very limited emissions reductions that could be achieved.²³ Second, EPA noted that proposing emission standards for

metal process heaters would run contrary to § 112's goals because they "would result in an overall increase in HAP emissions" by "providing a disincentive for switching to gas as a control technique (and a pollution prevention technique)"²⁴ These concepts are equally applicable to all gaseous fuels. Indeed, any standards that threaten to penalize the preferred practice of combusting process gases would pose a grave environmental threat. Process gasses are, by definition, the product of another process. If these gases are not reclaimed for their heat content (in place of natural gas or another fossil fuel), they are typically flared. Given the exorbitant costs EPA identified for controlling emissions from metal process furnaces, metal process furnaces currently burning process gas in lieu of natural gas might switch to natural gas exclusively and flare the process gas, resulting in "an overall increase in HAP emissions." Further, greenhouse gases and criteria pollutant emissions also would increase due to flaring the process gases while nearby boilers also combust virgin fossil fuels. To avoid that untoward result, work practices should apply equally to all metal process furnaces.

[Footnotes]

(23) *See 75 FR* at 32,025.

(24) *See 75 FR* at 32,025.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Dirk J. Krouskop

Commenter Affiliation: MeadWestvaco Corporation (MWV)

Document Control Number: EPA-HQ-OAR-2002-0058-3493-A1

Comment Excerpt Number: 10

Comment: MWV is encouraged by EPA's continued requirement for work practice standards for gas fired boilers. These units have inherently low emissions of hazardous air pollutants making add on control systems unnecessary.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Dirk J. Krouskop

Commenter Affiliation: MeadWestvaco Corporation (MWV)

Document Control Number: EPA-HQ-OAR-2002-0058-3493-A1

Comment Excerpt Number: 11

Comment: MWV is encouraged by EPA's continued requirement for work practice standards for gas fired boilers. These units have inherently low emissions of hazardous air pollutants making add on control systems unnecessary.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Jessica Bridges

Commenter Affiliation: United States Clean Heat & Power Association (USCHPA)

Document Control Number: EPA-HQ-OAR-2002-0058-3501-A1

Comment Excerpt Number: 5

Comment: We concur that a work practice standard is the appropriate standard for clean gas units.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 31

Comment: *GASEOUS FUEL SPECIFICATION*

ACC and its members strongly support the use of work practices as MACT for gas-fired boilers and process heaters. The following points summarize the arguments presented by ACC and others in previous comments and petitions for reconsideration.

HAP emissions from gas-fired boilers and process heaters are extremely low and cannot be reliably measured at these low levels due to deficiencies in both laboratory analysis methods and stack sampling methods. Detection limits reported in the test reports received by EPA during the boiler MACT data collection efforts varied greatly, pointing to the lack of repeatability of measurements at these very low levels.

As the majority of source emissions are below the reference method quantitation limits, the standard is appropriately set as a work practice standard and not an emission standard, since sources would not be able to accurately measure emissions against any numerical standard

ACC is not aware of any data that shows a correlation between a reduction in CO concentration and a corresponding reduction in organic HAP emissions below a CO concentration of approximately 100 ppmv for gas fueled (other Gas 1 fueled or Gas 2 fueled) sources. Thus, setting a very low standard for CO does not ensure a proportional reduction in the organic HAP emissions, and may have the unintended consequence of increasing emissions of other pollutants such as nitrogen oxides due to the combustion of additional fuel and suboptimal operating conditions.

Good combustion practices and periodic tune-ups as work practices will ensure proper operation of gas-fired units and continuous minimization of emissions. In fact, for gas-fired sources, these types of practices serve as MACT currently for minimizing organic HAP emissions.

Many gas-fired boilers and process heaters do not have vents or stacks to which EPA measurement methods can be applied, and to significantly modify the stacks would be technically infeasible in some applications and would be economically infeasible in many others.

Measurement infeasibility and control cost issues serve to justify the technical and economic feasibility criteria under §112(h) of the CAA for establishing work practices in lieu of numeric emission standards.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Alicia Meads

Commenter Affiliation: National Association of Manufacturers (NAM)

Document Control Number: EPA-HQ-OAR-2002-0058-3515-A1

Comment Excerpt Number: 4

Comment: The EPA has ample legal authority to set the standard in terms of a work practice. First, section 112(d)(1) authorizes – if not requires – the EPA to set "emission standards" for each category or subcategory, and section 302(k) defines "emission standard" to include work practice standards. Thus, if the EPA determines that the best performing sources achieved their emissions performance through work practices rather than control equipment, those work practices should be identified as the "floor." Second, section 112(h)(2)(b) independently authorizes the EPA to use a work practice standard where, as here, the application of a system for measuring the effect of the control measure for enforcement purposes is not practicable.

The EPA has independent authority to promulgate work practices as emission standards under CAA §302(k) as long as the work practices provide a continuous limit on emissions or are part of a set of regulations that provide a continuous limit on emissions. As required by CAA § 112(d), the EPA must promulgate "emission standards" for the control of hazardous air pollutants at major sources. Originally, these "emission standards" were found to be limited to only numeric emission limits. *See, e.g., Adamo Wrecking Co. v. U.S.*, 434 U.S. 275 (1978). However, in the 1990 Amendments, Congress expanded the definition of "emission standards" in §302(k) to expressly include work practices. As a result, the plain language of the Clean Air Act now authorizes the promulgation of work practices: (1) as direct emission standards under §302(k), and (2) in lieu of emission standards under CAA §112(h).

That statutory authority greatly simplifies the development of work practice standards for boiler units. Instead of turning to the alternate stop-gap provisions in §112(h) that apply when continuous emissions standards are not feasible, the EPA can focus on the direct establishment of work practices that existing sources use to ensure continuous compliance under §§112(d) and 302(k). For example, if the top 12% of existing natural gas-fired boilers are using tune-ups to achieve their "best performing" status, then the EPA has the authority to establish that protocol as a work practice-based emission standard. Tune-ups are an appropriate emission standard for these units because, if conducted with adequate frequency, they provide continuous reduction of the quantity and rate of HAP emissions from boilers by ensuring that they operate properly.

The NAM agrees with the EPA's conclusions regarding the basis for relying on work practices for units that combust only natural gas, refinery gas, or equivalent fuels. As the EPA recognizes, the capital cost of emissions controls for the numerous existing gas-fired boilers would be extraordinarily high. *See* 75 Fed. Reg. at 32,025, 32,029. Further, the EPA correctly concluded that imposing emission limitations on gas-fired boilers would create a disincentive for switching

to gas from oil, coal or biomass as a control technique. *Id.* In fact, it could create an incentive for facilities to switch away from gas to other fuels. Both outcomes should be avoided. Finally, the EPA recognized that "[t]he inability to accurately measure emission from Gas 1 units and the related economic impracticability associated with measuring levels that are so low that even carefully conducted tests do not accurately measure emissions warrant setting a work practice standard under CAA section 112(h)." 76 Fed. Reg. at 15,638.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 3

Comment: Instead of prescribing numeric HAP emissions limitations on boilers burning clean gas fuels (the "Gas 1" subcategory), EPA adopted work practices requiring a tune up of the boiler. EPA explained in the preamble to the June 4, 2010 proposal that:

[T]he need to employ the same emission control system as needed for the other fuel types would have the negative benefit of providing a disincentive for switching to gas as a control technique (and a pollution prevention technique) for boilers and process heaters in the other fuel subcategories. In addition, emission limits on gas-fired boilers and process heaters may have the negative benefit of providing an incentive for a facility to switch from gas (considered a "clean" fuel) to a "dirtier" but cheaper fuel (i.e., coal). It would be inconsistent with the emissions reductions goals of the CAA, and of section 112 in particular, to adopt requirements that would result in an overall increase in HAP emissions.²⁵ In short, EPA proposed that work practice standards are appropriate and justified for units in the Gas 1 subcategory out of concern for the cost of complying with numeric emissions limitations and based on the adverse policy incentives that would be created.

In the final rule, EPA provided further reasons for establishing work practices for Gas 1 boilers. EPA explained that "the measured emissions from these units are routinely below the detection limits of EPA test methods, and, as such, EPA considers it impracticable to reliably measure emissions from these units." 76 Fed. Reg. at 15638. EPA further explained that CO emissions test results were "below the level EPA considers to be a reliable measurement for more than 80 percent of the test runs that were conducted on Gas 1 units" and that the "case for other pollutants is even more compelling as the majority of measurements are so low as to cast doubt on the true levels of emissions that were measured during the tests." *Id.* Based on these data, EPA concluded that, "The inability to accurately measure emission from Gas 1 units and the related economic impracticability associated with measuring levels that are so low that even carefully conducted tests do not accurately measure emissions warrant setting a work practice standard under CAA section 112(h)." *Id.*

We concur with EPA's conclusions. For the gas-fired boiler and process heater source categories, it is not possible to discern in light of the reported data any economically or

technically practicable means of measuring compliance with a numeric emissions limitation. As a result, EPA has ample authority to set the standard for Gas 1 units in terms of a work practice.

[Footnote 25: *Id.*]

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Richard Krock
Commenter Affiliation: The Vinyl Institute
Document Control Number: EPA-HQ-OAR-2002-0058-3526-A1
Comment Excerpt Number: 5

Comment: The VI agrees that the periodic tune-ups proposed by EPA will ensure that Gas 1 combustion systems remain optimized according to manufacturers’ recommendations.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: John M. Cullen
Commenter Affiliation: Masco Corporation
Document Control Number: EPA-HQ-OAR-2002-0058-3661-A2
Comment Excerpt Number: 3

Comment: Masco agrees with EPA's decision in the Boiler MACT rules to impose work practice standards for natural gas boilers and process heaters in lieu of emission limitations, and submits that this will help encourage the use of this low-HAP containing fuel.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Annabeth Reitter
Commenter Affiliation: NewPage Corporation
Document Control Number: EPA-HQ-OAR-2002-0058-3662-A2
Comment Excerpt Number: 2

Comment: NewPage Corporation supports continuing to require work practice standards for gas 1 units.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Pamela Lacey
Commenter Affiliation: American Gas Association (AGA)
Document Control Number: EPA-HQ-OAR-2002-0058-3672-A2
Comment Excerpt Number: 1

Comment: AGA strongly supports EPA's proposal to apply a work practice standard to natural gas-fired industrial and commercial boilers at major sources, rather than an emissions limit. As noted in the preamble, EPA's "data for natural gas-fired units show the overwhelming majority of emissions to be below the level that can be accurately quantified by the available test methods." See 76 Fed. Reg. at 80609. We agree that it is inappropriate to impose emission limits given that natural gas boilers emit negligible or non-detectable amounts of hazardous air pollutants (HAPs). 76 Fed. Reg. 15608, 15638. Only poor combustion in these units could lead to HAP emissions, and the best way to ensure that natural gas-fired boilers and process heaters are operating properly and combusting efficiently is to conduct regular tune-ups.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 39

Comment: We strongly support EPA's conclusion that the CAA 112(h) criteria are met and therefore design, equipment, work practice, or operational requirements are the appropriate and legal means of meeting the requirements of CAA section 112(d)(2) for D/F emissions, for the Gas 1 and Limited-Use subcategories and for smaller boilers and process heaters (i.e., <10 MMBTU/hr).

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 43

Comment: Design or good combustion work practices are the appropriate standard for all gas 1-fired units since the combustion and emission characteristics of all gas 1-fired units are similar and emissions are so low that their measurement is technically and/or economically infeasible. Thus, EPA is legally correct in proposing work practice requirements for BPH firing gases other than natural gas and refinery gas, particularly to units firing chemical fuel gas, by establishing reasonable criteria for "other gas 1 fuels". See our comment on these criteria in Comment II.2.A, above. Chemical and refinery fuel-gas systems are often integrated at major sites and some chemical processes are present in some refineries as well as in chemical plants. Thus, establishment of a broad other gas 1 fuel category also reflects real operations and the gaseous fuels in use when the emissions data that serves as the basis for this rulemaking were collected.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Elizabeth McMeekin
Commenter Affiliation: PPG Industries, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-3778-A1
Comment Excerpt Number: 1

Comment: PPG strongly supports the use of work practices as MACT for gas-fired boilers.

HAP emissions from gas-fired boilers and process heaters are extremely low and cannot be reliably measured at these low levels due to deficiencies in both laboratory analysis methods and stack sampling methods.

Detection limits reported in the test reports received by EPA during the boiler MACT data collection efforts varied greatly, pointing to the lack of repeatability of measurements at these very low levels.

As the majority of source emissions are below the reference method quantitation limits, the standard is appropriately set as a work practice standard and not an emission standard, since sources would not be able to accurately measure emissions against any numerical standard.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Elizabeth McMeekin
Commenter Affiliation: PPG Industries, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-3778-A1
Comment Excerpt Number: 3

Comment: PPG strongly supports the use of work practices as MACT for gas-fired boilers.

Good combustion practices and periodic tune-ups as work practices will ensure proper operation of gas-fired units and continuous minimization of emissions. In fact, for gas-fired sources, these types of practices serve as MACT currently for minimizing organic HAP emissions.

Many gas-fired boilers and process heaters do not have vents or stacks to which EPA measurement methods can be applied, and to significantly modify the stacks would be technically infeasible in some applications and would be economically infeasible in many others.

Measurement infeasibility and control cost issues serve to justify the technical and economic feasibility criteria under §112(h) for requiring work practices in lieu of numeric emission standards.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Elizabeth McMeekin
Commenter Affiliation: PPG Industries, Inc

Document Control Number: EPA-HQ-OAR-2002-0058-3778-A1

Comment Excerpt Number: 4

Comment: Work practices are appropriate for units burning other process gases meeting the definition of "Other Gas 1 fuel" for the same reasons.

Many petrochemical and chemical process gases have HAP emissions at the ultra-low levels of natural gas. Measuring these ultra-low levels of HAP emissions is not feasible using existing methods.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

101B. Elimination of Work Practices for Small Units [DENIED PETITIONER ISSUE]

Commenter Name: Lenny Dupuis

Commenter Affiliation: Dominion Resources Services, Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3486-A1

Comment Excerpt Number: 5

Comment: We support EPA's decision to retain work practices rather than emission limits for smaller coal- and oil-fired units (under 10 mmBtu/hr) that were established in the March 2011 final rule.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Kenneth Anderson

Commenter Affiliation: Ameren Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3487-A1

Comment Excerpt Number: 7

Comment: Ameren requests US EPA reconsider whether a threshold higher than 10 million Btu per hour meets the technical and economic limitations as specified in CAA section 112(h).

Ameren raised this issue during comments on the proposed Boiler MACT rule but could not find that US EPA responded to this issue in the preamble or in the response to comments documents. Ameren believes that US EPA should consider setting only work practice standards for all liquid fuel fired boilers and process heaters below 100 MMBtu/hr as it does for units of all sizes in the gas 1 subcategory. Assuming a no.2 fuel oil fired 100 MMBtu/hr auxiliary boiler and using AP-42 particulate emission factors, average PM_{2.5} and Hg factors from the US EPA emission test database for the Boiler MACT rulemaking, the particulate emissions from that boiler is on the order of 6 tpy, PM_{2.5} on the order of 1.8 tpy and Hg on the order of 1.2 lb/yr. Using the US EPA summary of Capital and Annual Costs for control in Table 5 of the Preamble of the proposed rule, the average annualized cost of control for existing liquid fuel fired boilers after considering fuel savings is \$476,764 per boiler. In terms of cost effectiveness, assuming 100% reduction of all three pollutants, the annualized cost of reduction is \$79,460 per ton of PM reduction,

\$264,869 per ton of PM_{2.5} reduced and \$397,303 per pound of Hg reduced. We include PM and PM_{2.5} for this analysis because US EPA's benefits analysis for this proposed rule is based on PM_{2.5} reductions. At these costs, it does not make sense to require controls on small liquid fuel fired boilers as small as 100 MMBtu/hr. EPA should define work practice standards under CAA section 112(h) for these boilers similar to the limited use category.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 43

Comment: Addressing its work practice standards for smaller units, EPA also asserted for the first time in the final rule that it has not established a separate sub-category for smaller units (and acknowledged the lack of any justification for such a subcategory) even though it has provided a separate work practice standard for units burning any fuel at a rate less than 10 MMBtu per hour. Resp. Comments. Vol. 2 at 2818.1 Ex. 18. EPA nonetheless asserted authority to exempt sources from Section 112(d), based on the argument that it is too impracticable (or, in this case, expensive) for those units to employ the prescribed measurement methods. 76 Fed. Reg. at 15,641. Clean Air Act Section 112(h) only allows the Agency to set work practice standards instead of numeric standards only if there is no feasible method of measuring HAP emissions, 42 U.S.C. § 7412(h)(1). The Agency only asserts here that "the suite of test methods required by *this* final rule" are precluded by the design of these smaller units. 76 Fed. Reg. at 15,641 (emphasis added). That falls short of the statutory standard for the reasons provided in the Comments. Comments at 42-43, 45-48. Moreover, Section 112(h) does not provide the authority to create work practice standards that apply only to specified units within a category (or subcategory). It allows work practice standards in lieu of "emission standards." 42 U.S.C. § 7412(h)(1). "Emission standards," in turn, are those "achievable for new or existing sources in [a] category or subcategory." 42 U.S.C. § 7412(d)(2) (emphasis added). The Agency's refusal to establish numeric standards for small boilers, accordingly, is unlawful and lacks an adequate rationale.

Response: EPA disagrees with the commenter's interpretation of the Clean Air Act. Nothing in section 112(h) limits EPA's authority to establish work practice standards to an entire category or subcategory. Rather, if EPA finds that it is not feasible to prescribe or enforce an emission standard, the Agency may establish a work practice standard in lieu thereof. The fact that section 112(d)(2) requires that EPA establish "emissions standards" reflecting MACT for sources "in a category or subcategory" neither expressly nor implicitly prohibits EPA from exercising its discretion to establish work practice standards for a portion of a source category or subcategory, where the Agency concludes that it is infeasible to prescribe or enforce a numeric emissions limit only for some sources in the category or subcategory. Had Congress intended to so limit EPA's authority in section 112(h), it could have done so.

This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Robert R. Perry
Commenter Affiliation: FirstEnergy Generation Corp (FGCO)
Document Control Number: EPA-HQ-OAR-2002-0058-3518-A1
Comment Excerpt Number: 2

Comment: EPA should exempt small units (e.g. units less than 10 mmBtu/hr firing natural gas and/or liquid fuel) from tune-up work practice requirements under 40 CFR Part 63 Subpart DDDDD specifically Table 3 since the emissions from these units are insignificant. The impact of these units on the environment is negligible while further regulation places additional burdens on the regulated community as well as governmental agencies that will need to administer permits for these insignificant sources.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

New Data or Corrections to Existing Data

9A. New Data Submissions

Commenter Name: Nina Butler
Commenter Affiliation: Rock-Tenn Company
Document Control Number: EPA-HQ-OAR-2002-0058-3688-A2
Comment Excerpt Number: 3

Comment: NCASI analyzed the West Point mill's No. 8 Power Boiler CO CEMS data for the years 2009 to 2011 and determined that the No. 8 Power Boiler would have exceeded the proposed 28 or 35 ppm 10-day rolling average limits 23.6% or 9.7% of the time, respectively. The hourly average CO CEMS data for the West Point mill's No.8 Power Boiler for 2009 through 2011 are attached [see Attachment 1].

NCASI estimates that using this additional data to set the CEMS-based CO limit for the PC boiler subcategory would increase the 99% UPL values to 30 ppm and the alternate limit of the maximum 10-day rolling average would increase from 35 to 69 ppm. NCASI has included the results of this analysis for the No.8 Power Boiler CO CEMS data for years 2009 to 2011 in their comments on the Proposed BMACT Reconsideration Rule.

Response: The additional CO emissions data for the specified combustion unit have been incorporated into the EPA ICR Databases.

Commenter Name: Temple-Inland
Commenter Affiliation: Carole J. Stapper
Document Control Number: EPA-HQ-OAR-2002-0058-3423
Comment Excerpt Number: 2

Comment: Temple-Inland conducted another compliance stack test on BW-B001 on December 7, 2010, which is being submitted to EPA at this time. We believe it is imperative that EPA also

incorporate these data into the floor analysis so that the final short-term CO limit adequately reflects boiler variability. Please note that this stack test was conducted while firing a mixture of sander dust and natural gas, but since the sander dust firing rate was 94.6% of the total heat input, these data are representative of " biomass" firing. [See DCN: EPA-HQ-OAR-2002-0058-3423.2 for test report.]

Response: The results of the December, 2010 emissions testing of the specified combustion unit have been incorporated into the EPA ICR Databases and will be factored into future MACT floor analyses.

Commenter Name: Traylor Champion

Commenter Affiliation: Georgia-Pacific LLC (GP)

Document Control Number: EPA-HQ-OAR-2002-0058-3465-A1

Comment Excerpt Number: 26

Comment: Additional Carbon Monoxide emissions data for Muskogee #4 boiler and Leaf River Augusta, MS See Appendix C for copies of the Cover letters submitted with the data. [See submittal for Appendix C]

Facility: OKGPMuskogeeMill

Boiler: B-4

Facility: MSGPNewAugusta

Boiler: AA-015 Power Boiler

Response: The additional CO emissions data for the specified combustion units have been incorporated into the EPA ICR Databases.

Commenter Name: David A. Buff, Golder Associates Inc.

Commenter Affiliation: Florida Sugar Industry (FSI)

Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1

Comment Excerpt Number: 28

Comment: The FSI appreciates EPA's willingness to consider the FSI's data concerning hybrid suspension grate boilers, and it appears that EPA has appropriately considered the data that were previously submitted by the FSI. The FSI requests EPA to consider the additional data attached hereto and set an appropriate CO CEMS-based emission limit, as discussed in paragraph (9) below.

Response: The provided fuel sampling and emissions data have been incorporated into the EPA ICR Databases.

Commenter Name: David A. Buff, Golder Associates Inc.

Commenter Affiliation: Florida Sugar Industry (FSI)

Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1

Comment Excerpt Number: 32

Comment: The FSI previously provided EPA with several years of continuous hourly CO data for U.S. Sugar Company's Boiler No. 8, spanning the period October 2007 through March 2010. Boiler No. 8 is a new hybrid suspension grate boiler that was designed to comply with the 2004 Boiler MACT Rule for new sources. The FSI now is submitting additional CO CEMS data for Boiler No. 8, covering the period from March 2010 through December 2011, so that the entire database spans 2007 through 2011. The additional data are attached to this letter. Therefore, with this submittal, EPA will have a database that includes almost four years of operations, which should be more than adequate for EPA to establish a CO CEMS limit that is based on an averaging time of greater than 30 days. It is noted that these data do not include periods of malfunction, which are discussed separately below.

The CO CEMS data submitted to EPA for U.S. Sugar Company's Boiler No. 8 are the same data that are reported to the Florida Department of Environmental Protection under the Title V operating permit for Boiler No. 8. It is important to recognize, however, that the data do not include periods of time when the boiler experiences an upset condition (i.e., a malfunction). The exclusion of such periods of time is consistent with current law, which recognizes that malfunctions may occur due to a process upset or other conditions that are beyond the reasonable control of the operator. Upset conditions can occur due to a variety of reasons, including mill stoppages, plugged bagasse feeders in the boiler, bagasse piling up on the boiler grate, etc.

Response: The additional hourly CO emissions data for the specified combustion unit have been incorporated into the EPA ICR Databases.

Commenter Name: Ashok K. Jain

Commenter Affiliation: National Council for Air and Stream Improvement, Inc. (NCASI)

Document Control Number: EPA-HQ-OAR-2002-0058-3505-A1

Comment Excerpt Number: 23

Comment: In this subcategory, the MACT floor pool for CO has 10 units. One of these is ARWestFraser Huttig SN- 24, which has 3 tests (3/1/05, 8/6/09, and 3/18/10). As part of AF&PA's effort to obtain additional CO CEMS data for best performing units in this subcategory, this boiler was selected for installation of a temporary CEMS. Unfortunately, a major boiler failure occurred shortly after the installation and certification of the temporary CEMS which prevented further data collection. However, Method 10 tests were successfully carried out as part of CEMS certification, and these results are being submitted to EPA by West Fraser. The additional Method 10 runs should be incorporated in EPA's UPL calculations for the subcategory. Using EPA's UPL calculation methodology results in a 99% UPL of 1,000 ppm at 3% O₂ and a 99.9% UPL of 1,150 ppm at 3% O₂.

Response: The additional CO emissions data for the specified combustion unit have been incorporated into the EPA ICR Databases.

Commenter Name: Ashok K. Jain

Commenter Affiliation: National Council for Air and Stream Improvement, Inc. (NCASI)

Document Control Number: EPA-HQ-OAR-2002-0058-3505-A1

Comment Excerpt Number: 24

Comment: One of the five floor units for this subcategory is OKGPMuskogeeMill B-4. Georgia-Pacific is submitting an additional Method 10 test conducted in 2010. These additional three runs should be included in the floor calculations for the UPL. Our calculations using EPA's methodology indicate the existing source limit would be 51 ppm at 3% O₂ if based on the 99% UPL or 57 ppm based on the 99.9% UPL.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 26.

Commenter Name: Ashok K. Jain

Commenter Affiliation: National Council for Air and Stream Improvement, Inc. (NCASI)

Document Control Number: EPA-HQ-OAR-2002-0058-3505-A1

Comment Excerpt Number: 26

Comment: Due to concerns about the adequacy and representativeness of the limited CO CEMS data for these two subcategories, AF&PA and NCASI undertook an effort to obtain additional CO data by installing temporary CEMS on boilers already deemed to be best performers in the stack test-based MACT floors. Only two such boilers were ultimately identified for additional testing, one a wet biomass stoker unit (MSGPNew Augusta) and one a biomass fluidized bed unit (TNBewaterNewsprint). To date, NCASI has obtained 105 days of hourly average CEM data on the MSGPNew Augusta biomass stoker (10/20/11 to 2/1/12) and 49 days of hourly average CO CEM data for the TNBewaterNewsprint FBC unit (11/20/11 to 12/28/11), both these units being among the best performer list in their respective categories. The data for the TNBewaterNewsprint FBC unit are incomplete and could not be analyzed in time to meet the February 21 comment deadline. The data obtained thus far for the MSGPNewAugusta biomass stoker unit have been analyzed and 105 daily averages added to the 2119 daily averages representing four biomass stokers already analyzed by EPA.

Response: The additional data for TNBewaterNewsprint were not submitted and will not be incorporated into the EPA ICR Database. For a response to the additional data provided for MSGPNewAugusta, please see comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 26.

Commenter Name: Ashok K. Jain

Commenter Affiliation: National Council for Air and Stream Improvement, Inc. (NCASI)

Document Control Number: EPA-HQ-OAR-2002-0058-3505-A1

Comment Excerpt Number: 35

Comment: For PC-fired units, NCASI obtained 3 years duration of CO CEM data (2009, 2010 and 2011) from the VASmurfitStone Westpt unit that was used to calculate the 10-day rolling average floor of 28 ppm @3% O₂. Using the additional data, NCASI estimates the 99% UPL value would rise from 28 to 32 ppm @3% O₂, and the alternate limit rises from 35 to 67 ppm @3% O₂. As pointed out in the previous section 6a, the alternate limit based on determining the maximum 10-day rolling average in the data used to set the floor is much more defensible than a UPL-based limit.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3688-A2, excerpt 3.

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 66

Comment: PM emissions at existing facilities are commonly controlled with ESPs and baghouses. Emissions test data from the McNeil biomass plant in Vermont shows that filterable PM can be controlled well. [See submittal for Table 3-1. Summary of Particulate Matter Test Results.]

Response: The provided emissions data do not pertain to any known facility that is subject to the NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters at Major Sources. In fact, the permit for the McNeil biomass plant indicate that the facility is an area source of HAP. Thus, these data were not incorporated into the EPA ICR Databases.

Commenter Name: Stephen E. Woock

Commenter Affiliation: Weyerhaeuser Company

Document Control Number: EPA-HQ-OAR-2002-0058-3523-A1

Comment Excerpt Number: 24

Comment: EPA lists this unit (ES-017 WFB) at the Weyerhaeuser Dodson mill as a top performer for PM in the *Stoker/sloped grate/other unit designed to burn wet biomass* subcategory. EPA has in its database for this re-proposal two tests with average PM data of 0.00333 (2002 test) and 0.035 (2007 test). Two separate stack tests completed in 2010 and summarized in the table below put these tests in perspective, demonstrating an order-of-magnitude variability which shows the need for EPA to take stack test performance and perhaps, control technology performance over time into account. This unit could not reliably meet the proposed PM limit of 0.029 for wet biomass stokers based on the units test data, yet EPA has designated this unit as a top performer in that subcategory. The 2010 test reports are submitted as attachments to these comments (see attachments).

test run date and average PM emissions in lb/mmBtu:

- 2002/0.0033 (3 run test)
- 2007/0.035 (3 run engineering test)
- May 2010/ 0.0320 (3 run engineering test)
- July 2010/0.029 (4 run compliance test)

Response: The additional emissions testing data for the specified combustion unit have been incorporated into the EPA ICR Databases.

Commenter Name: Mark Weiss

Commenter Affiliation: Reciprocal Energy Company

Document Control Number: EPA-HQ-OAR-2002-0058-3658-A2

Comment Excerpt Number: 10

Comment: The accompanying data was collected at the Steam Center at Jackson Lab in Bar Harbor, Maine. [See DCN EPA-HQ-OAR-2002-0058-3658-A3] The plant was commissioned in Sept 2011. The setting is a laboratory campus bordering in the Acadia National Park. The plant complies with both State and Federal emissions requirements based on proximity to the Park. The facility will consume approximately 14,000 tons of pelletized biomass per year and replace over 1,250,000 gallons of #2 heating oil. The data is provided to illustrate the following:

- Frequency of steam loads below maximum fire rates
- Variations of steam load in daily operations
- Variations in CO levels due to firing rates and fuel.

Response: This facility is not a major source of hazardous air pollutant (HAP) emissions. Thus, the data from this facility were not incorporated into the EPA ICR Databases.

Commenter Name: Robert Ellerhorst

Commenter Affiliation: Michigan State University

Document Control Number: EPA-HQ-OAR-2002-0058-3674-A2

Comment Excerpt Number: 5

Comment: MSU has reviewed their calendar year 2010 CO CEMS data on our CFB unit and also recently collected CO emissions data on the three (3) PC units using a portable CEMS. This information is attached for your review. [See submittal EPA-HQ-OAR-2002-0058-XXXX for data provided by the commenter] The data for the CFB boiler shows that hourly CO emissions vary quite significantly. In fact, at the typical steam load for the CFB boiler, the majority of the hourly CO data is above the proposed 59 parts per million (ppm) standard. The data for the MSU PC units also show that CO tends to go above the proposed standard at normal operating loads, with a considerable increase when using SNCR control.

Response: The additional CO emissions data for the four combustion units specified have been incorporated into the EPA ICR Databases.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 182

Comment: Attachment 3: Chevron U.S.A. Inc., Kapolei Hawaii Refinery PM Boiler Stack Test Results.

The Chevron U.S.A. Inc., Kapolei Hawaii Refinery (Chevron) contracted with URS Corporation (URS) to perform measurements of particulate matter (PM) emissions from two identical boilers recently commissioned at the refinery. The boilers may be fueled by low sulfur fuel oil (LSFO) or refinery fuel gas (RFG), and are not equipped with air pollution control devices (APCD) to

control PM emissions. The boilers are manufactured by Foster Wheeler and are rated at 99 MMBtu/hr. Chevron requested that URS perform preliminary testing for PM/PM10 emissions to assess the performance of the boilers.

U.S. EPA Methods 5 and 17 are typically designed to measure total filterable PM emissions (PM-FIL), or PM emissions of all particle sizes. The primary difference between U.S. EPA Methods 5 and 17 is that Method 5 employs an out-of-stack filter heated to 248±25°F, while Method 17 employs an in-stack filter that collects PM at the temperature of the stack gas. However, both methods do not allow for quantification of various particle sizes (PM10-FILT, PM2.5-FILT).

Under certain sampling conditions, U.S. EPA Method 201A may be used to measure PM-FILT emissions. First, the stack must be equipped with a sampling port diameter of 4-6", depending on the type of in-stack filter used. Second, there must be no entrained water droplets in the stack gas. Both boilers (5 & 6) met these conditions.

U.S. EPA Method 201A was used with an in-stack cyclone and filter to separate PM larger than 10 µm from the PM10-FILT sample fraction and PM2.5-FILT sample fraction with the addition of a second in-stack cyclone and filter (see Figure 1). In addition, U.S. EPA Method 201A was combined with U.S. EPA Method 202 to measure "back-half" condensable PM (PM-CON).

[See submittal for Figure 2 for summary of PM test results.]

Response: EPA requested an emissions testing report for the additional test data for this facility, but the reports were unable to be provided. As such, the additional emissions data cannot be verified and have not been incorporated into the EPA ICR Databases. The facility does not plan to obtain a report for the additional emissions data.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 183

Comment: In January 2012, the Chevron U.S.A. Inc., Kapolei Hawaii Refinery obtained the following metals analysis for the Low Sulfur Fuel Oil used as liquid fuel in their boilers.

Response: The additional fuel sampling data for the specified facility have been incorporated into the EPA ICR Databases.

Commenter Name: Dell Majure

Commenter Affiliation: Kimberly-Clark Corp.

Document Control Number: EPA-HQ-OAR-2002-0058-3692-A2

Comment Excerpt Number: 6

Comment: The daily average CO CEM values in the appendix representing the last five years of operation show there is a significant difference in emission rates when the K-C FB with a FBHE fires culm mixed with and without petroleum coke.

Response: The CO continuous monitoring data provided by the commenter have been incorporated into the EPA ICR Databases.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 65

Comment: Also see DCNEPA-HQ-OAR-2002-0058-3677-A3 Attachment 3. Chevron, Kapolei, Hawaii, PM Boiler Stack Test Results.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 182.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 73

Comment: Attachment 4 [see DCNEPA-HQ-OAR-2002-0058-3677-A3 Attachment 3. Chevron, Kapolei, Hawaii, PM Boiler Stack Test Results] provides some recently obtained TSM analysis results for the low sulfur fuel oil used in some of the boilers at the Chevron Hawaii Refinery.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 183.

9B. Data Corrections

Commenter Name: Traylor Champion

Commenter Affiliation: Georgia-Pacific LLC (GP)

Document Control Number: EPA-HQ-OAR-2002-0058-3465-A1

Comment Excerpt Number: 24

Comment: Remove Russellville Chemical FO Boiler from boiler inventory; as the facility has ceased operations.

The Russellville Chemical operations and FO Boiler has ceased operations and this boiler should be removed from the floor calculation for the light fuel oil subcategory. The Air Emission Operating Permit# TV-0420-0013 for the site has been relinquished and the site is no longer permitted to operate. Find attached in Appendix A, the EPA request to remove this source from the inventory and the correspondence from Georgia-Pacific to the State of South Carolina relinquishing the operating permit and the corresponding letter from South Carolina terminating this operating permit. [See submittal for Appendix A]

Facility: *SCGPChemRussellville*

Boiler: *FO Boiler*

Response: The EPA ICR Databases have been updated to show that this facility has been permanently shut down.

Commenter Name: Traylor Champion

Commenter Affiliation: Georgia-Pacific LLC (GP)

Document Control Number: EPA-HQ-OAR-2002-0058-3465-A1

Comment Excerpt Number: 25

Comment: Remove Wauna from the Liquid inventory; it is no longer permitted to use liquid fuel.

The GP Wauna Pulp and Paper Mill – Boiler Number EU-33 is no longer permitted to burn liquid fuels and therefore should be removed from the floor calculation for the heavy liquid subcategory. The Oregon Title V Operating Permit# 04-0004 has been modified to prohibit the burning of fuel oil in this unit. Find attached in Appendix B, the EPA request to remove this source from the inventory and Page 27 of 78 from the operating permit where burning of fuel oil specifically prohibits in the boiler. [See submittal for Appendix B]

Facility: ORGeorgiaPacificWaunaMill Boiler: EU33 - Power Boiler

Response: The EPA ICR Databases have been updated to show that the specified combustion unit is no longer permitted to combust liquid fuels.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 58

Comment: During our examination of the units in the liquid fuel subcategories, we discovered that several of the units that were considered are either no longer in operation or are no longer permitted to burn liquid fuels. Among these are:

- ORGeorgiaPacificWauna-EU 33 (fuel oil has been removed as a permitted fuel for this unit in the facilities Title V permit),
- SCGPChemRussellville-FOBoiler (This facility is no longer in operation and the unit is being dismantled), and
- NCDomtar-66-25-2050 (The No. 1 Package Boiler is no longer in operation and has been removed from the NC site).

These units should not be used in liquid unit floor calculations.

Response: For responses to the specified data corrections pertaining to SCGPChemRussellville and ORGeorgiaPacificWaunaMill, please see DCN EPA-HQ-OAR-2002-0058-3465-A1, Excerpts No. 24 and 25, respectively. EPA confirmed with NCDomtar that the specified

combustion unit has been permanently shut down; the EPA ICR Databases have been updated to reflect that this unit has been permanently shut down.

Commenter Name: Temple-Inland

Commenter Affiliation: Carole J. Stapper

Document Control Number: EPA-HQ-OAR-2002-0058-3423

Comment Excerpt Number: 1

Comment: In the proposed rule, there were several changes in boiler subcategories, including a separate subcategory created for biomass suspension burners that resulted in a short term CO limit of 58 ppm @ 3% O₂. The best performer for this subcategory is the Temple-Inland boiler at the Thomson Particleboard Plant (Facility ID GATempleinlandThomson, Unit ID BW-B001). Three stack test reports were submitted to EPA for BW-B001 (1/30/03, 12/7/04, and 12/3/08); however, it appears that the December 2004 test was not included in the floor analysis due to a concern that the CO data was not generated according to EPA Method 10. After further review, it appears that the stack test data provided to EPA was not for the December 2004 compliance test conducted on BW-B001, but was instead an "Investigative Emission Test Report" dated January 2005 that did not include CO testing at the boiler. To correct the record, Temple-Inland is submitting the "Compliance Emission Test Report Boiler/ESP B001" dated December 2004. As noted in the [See DCN EPA-HQ-OAR-2002-0058-3423.1 (page 3-3)], Method 10 was used for this stack test; therefore, we are requesting that these data be incorporated into the floor analysis.

Response: The reported emissions testing data have been updated accordingly in the EPA ICR Databases and will be factored into future MACT floor analyses.

Commenter Name: Traylor Champion

Commenter Affiliation: Georgia-Pacific LLC (GP)

Document Control Number: EPA-HQ-OAR-2002-0058-3465-A1

Comment Excerpt Number: 22

Comment: Currently, in its Boiler MACT database, EPA shows that GP has two process heaters identified as being affected sources under Boiler MACT. We believe these units should not be affected emissions sources under Boiler MACT because these units are currently regulated as an affected source subject to the requirements under the Plywood and Composite Wood Products (PCWP) MACT (40 CFR Part 63 Subpart DDDD). As noted in §63.7491(h) of the proposed Boiler MACT rule, these units would not be subject to this regulation if already subject to another MACT standard. The facilities are identified in the Boiler MACT emissions database as VAGeorgiaPacificBrooknealGladys and WVGPMtHopeOSB; and these units should be removed from EPA's emissions source database. The following is a detailed description of the facilities and the basis GP has utilized in determining these units are not subject to Boiler MACT: GP has two unique oriented strand board (OSB) facilities that use an integrated wood-fired heat source serving the dual function of supplying the heat required in the flake drying process and also heating thermal oil for the press. At each facility, these integrated wood-fired heat sources consist of a 240 MMBtu/hr Wellons Energy System, 3 rotary flake dryers, and 6 air-to-air heat exchangers all interconnected (see enclosed process flow diagram below). Heat for the drying system is provided by the Wellons Energy System. The combustion gases generated in

the Wellons Energy System are routed to an air-to-air heat exchanger (Primary Air Heater, one per dryer) to heat ambient air for use in that dryer. As needed to maintain dryer operating conditions, approximately 15% of the combustion gases entering the primary air heater can be sent directly to the dryer without going through the heat exchanger. These combustion gases come in direct contact with the process material. The heated ambient air and combustion gases are sent to each dryer where they are used to both convey the flakes through the dryer and to remove the moisture from the flakes. The dry flakes from each dryer are pneumatically conveyed to a cyclone collector where they are removed from the gas stream. The moisture laden dryer exhaust (process gases) from the cyclone is routed to another air-to-air heat exchanger (Recuperator, one per dryer) where it is re-heated to prevent condensation prior to being sent back to the Wellons Energy System for use as combustion air.

This system also includes a thermal oil heat exchanger where the combined combustion gases/process gases from the Wellons Energy System are used to indirectly heat thermal oil for use in the process. The combustion/process gases routed through the thermal oil heat exchanger represent a relatively small proportion of the heat source output (less than 20% of total heat output), and are re-combined with the combustion/process gases used in the drying process prior to entering a dry electrostatic precipitator before exhausting to the atmosphere.

GP urges EPA to:

a. **Remove the two units identified in the comments** (VAGeorgiaPacificBrooknealGladys and WVGPMtHopeOSB) from the Boiler MACT emissions source database.

Response: The EPA agrees that the specified combustion units are subject to 40 CFR Part 63, Subpart DDDD. The units have been removed from the major source inventory of industrial, commercial, and institutional boilers and process heaters.

Commenter Name: Sarah E. Amick

Commenter Affiliation: Rubber Manufacturers Association (RMA)

Document Control Number: EPA-HQ-OAR-2002-0058-3503-A1

Comment Excerpt Number: 13

Comment: During our examination of the units in the liquid fuel subcategories, we discovered several of the units that were considered are either no longer in operation or are no longer permitted to burn liquid fuels. Among these are: ORGeorgiaPacificWauna-EU 33 (fuel oil has been removed as a permitted fuel for this unit in the facilities Title V permit), SCGPChemRussellville-FOBoiler (This facility is no longer in operation and the unit is being dismantled), and NCDomtar-66-25-2050 (The No. 1 Package Boiler is no longer in operation and has been removed from the NC site).

These units should not be used in liquid unit floor calculations.

Response: For responses to the specified data corrections pertaining to SCGPChemRussellville and ORGeorgiaPacificWaunaMill, please see comment EPA-HQ-OAR-2002-0058-3465-A1, excerpts 24 and 25, respectively. For a response to the specified data correction pertaining to NCDomtar, please see comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 58.

Commenter Name: Ashok K. Jain

Commenter Affiliation: National Council for Air and Stream Improvement, Inc. (NCASI)

Document Control Number: EPA-HQ-OAR-2002-0058-3505-A1

Comment Excerpt Number: 22

Comment: The GATempleInlandThomson BW B-001 boiler had the lowest Method 10 CO test result for boilers in the biomass suspension burner subcategory. Although Version 7.0 of the emissions database had three Method 10 tests for this unit, there is a note regarding the 12/7/04 test:

“This is not actually a Method 10 test but an average CEMS reading, not appropriate to use this test to assess variability and CEMS average is much larger than test average; do not use for baselines or floors.”

The company has submitted the 12/7/04 compliance test report (not previously submitted to EPA) that shows Method 10 procedures were followed. The company has also submitted a 2010 test report not previously provided to EPA.

Using EPA’s UPL calculation methodology for all Method 10 test runs results in a 99% UPL of 11,300 ppm at 3% O₂ and a 99.9% UPL of 13,400 ppm at 3% O₂. EPA should use all available data for this unit to set the final new and existing source CO limits for this subcategory.

Response: The EPA has reviewed the provided test report and agrees with the commenter's assertion that the data follows the appropriate Method 10 procedures and guidelines. The EPA ICR Databases have been updated accordingly, and the December, 2004, compliance test data will be factored into future MACT floor analyses.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 59

Comment: Some of our members have solid fuel units that have been misclassified, either by fuel type or design subcategory, or the operation is closed. The individual member companies are submitting comments to EPA to identify these mis-classifications and other circumstances. EPA should also consider the final NHSM rule when determining which units that are currently in the CISWI database need to be moved to the Boiler MACT database. We believe many more materials are fuels (and not waste) than EPA has initially determined. These changes will affect not only floor setting but also cost and emissions impacts estimates.

Response: The final inventory of major source industrial, commercial, and institutional boilers and process heaters was developed simultaneously with the NHSM and CISWI standards. Sources determined to be combusting non-hazardous materials that are solid waste were removed from the major source industrial, commercial, and institutional boiler and process heater inventory. The methodology used to develop the inventory of major source industrial, commercial, and institutional boilers and process heaters is described in the January, 2011 memorandum from ERG to EPA entitled, "Development of Baseline Emission Factors for Boilers and Process

Heaters and Commercial, Industrial, and Institutional Facilities." Comments on fuels that shall (or shall not) be classified as solid waste pertain to the Identification of Non-Hazardous Materials That Are Solid Waste rulemaking and are out of scope for this boiler rulemaking.

Commenter Name: Dean C. DeLorey

Commenter Affiliation: The Amalgamated Sugar Company LLC (TASCO)

Document Control Number: EPA-HQ-OAR-2002-0058-3522-A1

Comment Excerpt Number: 7

Comment: The PM test data for the Foster Wheeler boiler at the Twin Falls facility was not a permit compliance test requirement. As a result, it's important to recognize that this test was not approved by the state agency including all appropriate *QA/QC* procedures. It is recommended that only performance test quality data be utilized when developing Boiler MACT emission standards.

Response: The EPA reviewed the test report for the specified emissions testing conducted by the facility and notes that the test passed the basic *QA/QC* procedures. The EPA does not recognize any technical reason for dismissing the results of tests not conducted for compliance purposes if basic *QA/QC* procedures are conducted.

Commenter Name: Stephen E. Woock

Commenter Affiliation: Weyerhaeuser Company

Document Control Number: EPA-HQ-OAR-2002-0058-3523-A1

Comment Excerpt Number: 19

Comment: EPA lists this unit (SN-45) at the Weyerhaeuser Dierks mill as a top performer for both CO and PM in the *Dutch ovens/pile burners designed to burn biomass/bio-based solid* subcategory. We believe this unit is a *Fuel Cell* and should be listed in that subcategory.

In the re-proposed rule EPA has the following three definitions:

Dutch oven means a unit having a refractory-walled cell connected to a conventional boiler setting. Fuel materials are introduced through an opening in the roof of the dutch oven and burn in a pile on its floor. Fluidized bed boilers are not part of the dutch oven design category.

Pile burner means a boiler design incorporating a design where the anticipated biomass fuel has a high relative moisture content. Grates serve to support the fuel, and underfire air flowing up through the grates provides oxygen for combustion, cools the grates, promotes turbulence in the fuel bed, and fires the fuel. The most common form of pile burning is the dutch oven.

Fuel cell means a boiler type in which the fuel is dropped onto suspended fixed grates and is fired in a pile. The refractory-lined fuel cell uses combustion air preheating and positioning of secondary and tertiary air injection ports to improve boiler efficiency. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, and suspension burners are not part of the fuel cell subcategory. The Dierks SN-45 combustion unit is a 4-cell unit with secondary and tertiary air injection points. Combustion air is preheated. These are key features of a Fuel Cell in the re-proposal definition.

The Dierks SN-45 combustion unit is a 4-cell unit with secondary and tertiary air injection points. Combustion air is preheated. These are key features of a Fuel Cell in the re-proposal definition.

Response: The EPA ICR Databases have been updated to reflect that the specified combustion unit should be classified as a Fuel Cell designed to combust biomass/bio-based solid fuels rather than a Dutch Oven/Pile Burner.

Commenter Name: Stephen E. Woock

Commenter Affiliation: Weyerhaeuser Company

Document Control Number: EPA-HQ-OAR-2002-0058-3523-A1

Comment Excerpt Number: 20

Comment: EPA lists this unit (AA-002) at the Weyerhaeuser Bruce mill as a top performer for CO, PM, HCl, and TSM in the *Dutch ovens/pile burners designed to burn biomass/bio-based solid* subcategory. We believe this unit is a *Fuel Cell* and should be listed in that subcategory.

The Bruce AA-002 is a 4-cell unit with secondary and tertiary air injection points. Combustion air is preheated. These are key features of a Fuel Cell in the re-proposal definition (see definitions in the comment above).

Response: The EPA ICR Databases have been updated to reflect that the specified combustion unit should be classified as a Fuel Cell designed to combust biomass/bio-based solid fuels rather than a Dutch Oven/Pile Burner.

Commenter Name: Stephen E. Woock

Commenter Affiliation: Weyerhaeuser Company

Document Control Number: EPA-HQ-OAR-2002-0058-3523-A1

Comment Excerpt Number: 21

Comment: EPA lists this unit (EU 001) at the Weyerhaeuser Ironton (aka Deerwood) mill as a top performer for CO and PM in the *Fuel Cell* subcategory. This facility has been closed and is not expected to reopen. EPA should remove this combustion unit from its database.

Response: The EPA ICR Databases have been updated to reflect that the specified facility is permanently shut down.

Commenter Name: Stephen E. Woock

Commenter Affiliation: Weyerhaeuser Company

Document Control Number: EPA-HQ-OAR-2002-0058-3523-A1

Comment Excerpt Number: 22

Comment: EPA lists this unit (MP 01-01) at the Weyerhaeuser East Kentucky mill as a top performer for CO in the *Dutch ovens/pile burners designed to burn biomass/bio-based solid* subcategory. EPA should remove this combustion unit from its database for two reasons. (1) This unit was subject to and permitted as a direct firing process heater subject the PCWP MACT

(Subpart DDDD) and therefore would not be subject to Boiler MACT. (2) This facility has been closed and is not expected to reopen.

Response: The EPA ICR Databases have been updated to reflect that the specified facility is permanently shut down.

Commenter Name: Stephen E. Woock

Commenter Affiliation: Weyerhaeuser Company

Document Control Number: EPA-HQ-OAR-2002-0058-3523-A1

Comment Excerpt Number: 23

Comment: EPA lists this unit (MP 01-03) at the Weyerhaeuser East Kentucky mill as a top performer for CO in the *Dutch ovens/pile burners designed to burn biomass/bio-based solid* subcategory. EPA should remove this combustion unit from its database for two reasons. (1) This unit was subject to and permitted as a direct firing process heater subject the PCWP MACT (Subpart DDDD) and therefore would not be subject to Boiler MACT. (2) This facility has been closed and is not expected to reopen.

Please note, KYWeyerhaeuserEKY / MP 01-02 is not listed as a top performer but should be removed from the floor database for the same reasons.

Response: The EPA ICR Databases have been updated to reflect that the specified facility is permanently shut down.

Commenter Name: Bruce A. Steiner

Commenter Affiliation: American Coke and Coal Chemical Institute (ACCCI)

Document Control Number: EPA-HQ-OAR-2002-0058-3547-A2

Comment Excerpt Number: 9

Comment: EPA's current database is insufficient to understand emissions from coke oven gas-fired sources. Of the three units identified in the EPA database as coke oven gasfired, two have been confirmed as burning petroleum coke, a solid fuel, and not coke oven gas. These data must be excluded from any gaseous fuel analysis. The only remaining emissions data in the EPA dataset for coke oven gas-fired units comes from a source test snapshot of a byproduct coke plant in West Virginia that uses a desulfurization system. This limited data from a single source cannot adequately represent the variability inherent in the coke oven gas-fired sources identified by EPA within the Gas 2 subcategory. However, the data can, and do, indicate significant differences between coke oven gas emissions and other Gas 2 process gases.²⁷

[Footnote]

(27) For a discussion of these differences, we direct you to the comments of the American Petroleum Institute and the National Petrochemical Refiners Association, which reveal significant differences in the emission characteristics among the Gas-2 fuels.

Response: Since the two units burning petroleum coke were not specified, no changes were made to the EPA ICR Databases.

Commenter Name: Christopher Coleman
Commenter Affiliation: HOVENSA LLC. , Hess Corporation
Document Control Number: EPA-HQ-OAR-2002-0058-3673-A2
Comment Excerpt Number: 1

Comment: Until very recently, HOVENSA L.L.C. ("HOVENSA") operated a crude oil petroleum refinery on the island of St. Croix, United States Virgin Islands (USVI), a territory of the United States. Subsidiaries of Hess Corporation and Petroleos de Venezuela each own 50% interests in the facility. The refinery has a permitted crude oil refining capacity of 525 thousand barrels of oil per day (BOPD) but had reduced that capacity to approximately 350 BOPD in April 2011 and shut down the remaining capacity in February, 2012. The facility provided petroleum products to the eastern seaboard of the United States, and accounted for a substantial percentage of the transportation and heating fuels supplied to the entire region, particularly for the Caribbean, Florida and the Mid-Atlantic and New England.

Response: The EPA ICR Databases have been updated to reflect that the specified facility is permanently shut down.

Commenter Name: Douglas Emerson et al.
Commenter Affiliation: American Crystal Sugar Company et al.
Document Control Number: EPA-HQ-OAR-2002-0058-3675-A2
Comment Excerpt Number: 4

Comment: In addition to the exclusion of certain data, it was also noted that errors were present in the data included in the 2008 survey database for those boilers that were included. Specifically, under Appendix B-6e: Unit Rankings for Filterable PM from Stoker Coal/Solid Fossil Fuel Units (Recommended Option), information presented for MNAmericanCrystalCrockston Boiler 1 indicates three (3) boiler tests and a final emission rate of 0.001733 lb/MMBtu, which results in a Number 4 overall ranking for this unit and placing it in the Top 12 Percent. A review of the Emission Test Spreadsheet submitted to the EPA in EPA Docket Center (EPA/DC) October of 2008 under provisions of Section 114 of the Clean Air Act indicate only one test was performed for Boiler 1 and the submitted emission rate was 0.0037 lb/MMBtu, which would result in a ranking of approximately Number 15.

Whether the differences between reported data and what appears in the 2008 survey database is a result of errors and omissions, or there was some quality control or statistical evaluation to review data entries, the process must be transparent and reviewed by stakeholders of the proposed rule. Any statistical evaluation used to exclude certain data is of vital importance with regard to transparency due to the variable operation of industrial boilers.

Response: Due to an error in the reported combustor ID attributed to each of the three reported particulate matter tests, all of the data were being attributed to Boiler #1. After a review of the reported emissions testing data, the EPA agrees that only one test was conducted on Boiler #1. The emissions data reported from a test conducted on 11/2/2005 have been attributed to Boiler #2. The emissions data reported from a test conducted on 11/3/2005 have been attributed to Boiler #3.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 67

Comment: Note that EPA's emissions database

"emissions_database_boilersprocessheaters_containingstacktest_cem_fuelanalysis_data_reported_under_icr_2286-01and_2286-03_ver7.mdb" included CO stack test results for HITesoro unit SG1103 dated 9/26/2002 and 9/26/2008 that were listed as combusting 100% residual oil. As well, the database included three separate stack tests for HITesoro H503 dated 10/4/2005, 9/28/2006, and 12/17/2007, each noted as combusting 100% residual oil. Tesoro has reviewed each of these test reports and confirmed that none of them were tested at 100% residual oil, and either were based on 100% refinery fuel gas, or co-fired with refinery fuel gas. As such, none of these test results have been included in the suggested analysis.

Response: The specified corrections have been processed in the EPA ICR Databases.

Commenter Name: Nina Butler

Commenter Affiliation: Rock-Tenn Company

Document Control Number: EPA-HQ-OAR-2002-0058-3688-A2

Comment Excerpt Number: 1

Comment: As noted in the Coalition's comments, some of the Coalition members' solid fuel units are misclassified in EPA's database or have been shutdown. Some of the data in EPA's database is incorrect for nine of the boilers at RockTenn's facilities. The corrected data is provided in Table I attached to these comments. [See submittal for Table I.]

Response: The updates specified to the combustion unit classifications and facility operating status specified in Table 1 have been implemented accordingly in the EPA ICR Databases.

Commenter Name: M.L. Steele

Commenter Affiliation: CraftMaster Manufacturing, Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3814-A1

Comment Excerpt Number: 6

Comment: An example of a questionable categorization is CraftMaster's (PACraftmaster) No3 Boiler that fires biomass through a combination of Air-swept Stokers firing wet biomass (20.7% of heat input in 2011), Suspension Burners firing dry biomass (60.7%), and Natural Gas (18.6%). Suspension Burners used by CraftMaster are similar to pulverized coal burners. (Historically the fraction of annual heat input from the suspension burners has been higher but was down recently because of lower process steam demand due to the severely depressed market conditions in the building products industry.) Per the "CO CEMS MACT Floor Analysis (November, 2011),"USEPA has classified the No3 Boiler in the "Stoker/ Sloped Gate/ Other" combustor design subcategory firing wet biomass based on the hierarchy. However, the air-swept stokers provided only about 1/5 of the heat input in 2011. The primary firing method in 2011 was

the suspension burners with 3/5 of the heat input. Then under the hierarchy approach the primary firing method employed is not considered by USEPA in establishing what subcategory a unit is in. We believe the No3 Boiler would be more accurately classified in the "Suspension Burner" biomass subcategory for compliance purposes. Also we believe the No3 Boiler CO CEMS data should not be considered in the CO CEMS MACT Floor for the wet biomass "Stoker/ Sloped Gate/ Other" combustor design subcategory. Most of the heat input was from the suspension burners and no CO CEMS data was generated while the unit was fired on $\geq 90\%$ stoker firing.

Response: The No. 3 Boiler at the facility has been reclassified as a Suspension Burner in the EPA ICR Databases.

9C. QA of Test reports

Commenter Name: Vickie Woods

Commenter Affiliation: Division of Air Quality, North Carolina Department of Environment and Natural Resources (NCDENR)

Document Control Number: EPA-HQ-OAR-2002-0058-3663-A2

Comment Excerpt Number: 15

Comment: QA. EPA performed a Data Quality Review of Best Performers for PM, Hg, HCl, CO, and Dioxin/Furan Emissions for the MACT database.

Given its fundamental importance, several NC DAQ staff are assigned to observe emission tests to ensure protocols are followed and review the ensuing reports to verify data quality. Likewise, it is worthwhile for EPA to collect copies of all of the emission test reports for the best performing units in order to perform additional quality assurance. It is not surprising this level of review resulted in multiple changes to the emission data set, invalidation of some emission tests, improved the quality of the industry provided data, and enhanced the confidence of the responsible agency on their official determinations.

Response: The EPA thanks the commenter for their support.

9Z. Other

Commenter Name: Vickie Woods

Commenter Affiliation: Division of Air Quality, North Carolina Department of Environment and Natural Resources (NCDENR)

Document Control Number: EPA-HQ-OAR-2002-0058-3663-A2

Comment Excerpt Number: 14

Comment: New emission data. EPA received additional data to incorporate into MACT database, including 36 Hg test runs, 168 PM test runs, 24 dioxin/furan test runs, 133 CO test runs, 63 HC1 test runs, and 22 TSM test runs.

NC DAQ supports the use of additional emission data, fuel analyses, CO CEMS data, and corrections to data and to descriptions of combustion units for incorporation into the MACT database.

Response: The EPA thanks the commenter for their support.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 24

Comment: In addition, fuel variability data should be collected for all units setting new source floors and factored into the calculated emission limits. Industrial boilers operate over a variety of conditions and fire a variety of fuels, so adequate consideration of variability is important in setting achievable emission limits.

Response: Fuel variability was factored into the calculated MACT floor emission limits for new sources when available data warranted it. The mercury, HCl, and TSM floors for liquid units and TSM for coal units incorporates fuel analysis variability.

Commenter Name: Douglas Emerson et al.

Commenter Affiliation: American Crystal Sugar Company et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3675-A2

Comment Excerpt Number: 2

Comment: After review of the "Survey Database containing Results of the 2008 Questionnaire for Boilers, Process Heaters, & Other Combustion Units (ICR No. 2286.01) (version 3)" posted on the EPA website at <http://www.epa.gov/ttn/atw/boiler/boilerpg.html>, it has come to our attention that there is a significant amount of error in the small population of data reviewed by us. This has far reaching and serious ramifications considering the conclusions that can be drawn from the review. If a small sample population of reviewed sources reflects a large amount of error, it can only be representatively assumed that a larger sample population would also contain a high degree of error. Considering these parallels, especially in light of the uniform data collection procedures used by the EPA to collect and process the initial data, there is a possibility of serious erroneous conclusions and subsequent proposed emission limitations in the proposed rule.

The sample population reviewed includes data submitted by three sugar beet processing companies, which include American Crystal Sugar Company, Michigan Sugar Company and MinnDak Farmers Cooperative.

Response: EPA has made substantial revisions to the database since the June, 2010 proposed rule. These revisions have been based on specific corrections identified and submitted by facilities, corrections based on internal review of emissions testing reports, and additional data submissions received since the June, 2010 proposal. These substantial changes are discussed in the original and updated versions of the January 2011 memorandum from Graham Gibson, ERG, to EPA entitled "Handling and Processing of Corrections and New Data in the EPA ICR Databases".

Commenter Name: Richard D. Garber
Commenter Affiliation: Boise Inc.
Document Control Number: EPA-HQ-OAR-2002-0058-3686-A2
Comment Excerpt Number: 24

Comment: EPA should review and correct problems in the data that are being used to establish the MACT "floor" for various subcategories, including the wet biomass stoker category.

Boise understands that additional CO stack test CEM data has been provided to EPA for boilers that would make up the MACT floor since the December 23, 2011 proposed rule. We also understand that detailed AF&PA and NCASI comments have been submitted that point to various floor units that are inappropriately included in the floor for several subcategories.

Because development of the floor emission levels is a difficult and complex process, and because it is absolutely critical to Boise and others in the regulated community that the floor be established correctly for legal and technical reasons, and because the floor units should be able to achieve continuous compliance with the proposed standards at all times, we respectfully request that EPA carefully consider the detailed comments submitted by NCASI and AF&PA on this issue.

Response: For response to issues with the EPA ICR Databases containing problematic or erroneous data, please see DCN EPA-HQ-OAR-2002-0058-3675-A2, Excerpt No. 2. The additional CO emissions data provided by the additional commenters have been incorporated into the EPA ICR Databases.

Commenter Name: Dean C. DeLorey
Commenter Affiliation: The Amalgamated Sugar Company LLC (TASCO)
Document Control Number: EPA-HQ-OAR-2002-0058-3522-A1
Comment Excerpt Number: 6

Comment: The Amalgamated Sugar Company LLC would like to further clarify some of the emissions stack test data provided to EPA as part of the Boiler MACT Survey. The survey was originally completed in October 2008. Trace metal data (HCl, Hg, other metals) was based on very limited stack testing. This data would likely be considered as poor quality in accordance with EPA AP-42 criteria.

Response: EPA has made substantial revisions to the database since the June, 2010 proposed rule. These revisions have been based on specific corrections identified and submitted by facilities, corrections based on internal review of emissions testing reports, and additional data submissions received since the June, 2010 proposal. These substantial changes are discussed in the original and updated versions of the January 2011 memorandum from Graham Gibson, ERG, to EPA entitled "Handling and Processing of Corrections and New Data in the EPA ICR Databases".

Rule Language Corrections

10A. Rule Language: Definitions (Existing)

Commenter Name: Felix Mestey, on behalf of Donald R. Schregardus

Commenter Affiliation: Clean Air Act Services Steering Committee, Department of Defense (DoD)

Document Control Number: EPA-HQ-OAR-2002-0058-3427

Comment Excerpt Number: 8

Comment: EPA should revise the “unit designed to burn...” definitions to prevent overlap. Currently the definition of “*unit designed to burn liquid subcategory*” overlaps with “*unit designed to burn gas 2 (other) subcategory*.” For example: consider a unit that: 1) burns gas 1 fuel and liquid fuel at times other than periods of gas curtailment or supply interruption and/or burns liquid more than 48 hours for testing and/or burns liquid for other non-testing purposes; and 2) burns less than 10% liquid on an annual basis. This unit is clearly not in the “*unit designed to burn gas 1 subcategory*.” But it does meet the definitions of both a “*unit designed to burn liquid subcategory*” and a “*unit designed to burn gas 2 (other) subcategory unit*.” It meets the “*unit designed to burn liquid subcategory*” definition because it burns “any” liquid fuel and no solid fuels in combination with gaseous fuel. It meets the “*unit designed to burn gas 2 (other) subcategory unit*” definition because 1) it is not in the gas 1 subcategory, and 2) burns “any” gaseous fuels in combination with less than 10% liquid fuels as well as less than 10% coal/solid fossil fuel and less than 10% biomass. To prevent overlap and misapplication, EPA should consider revising the definition of “*unit designed to burn gas 2 (other) subcategory unit*” as follows:

Alternative 1:

Unit designed to burn gas 2 (other) subcategory includes any boiler or process heater that is not in the unit designed to burn gas 1 subcategory and burns any gaseous fuels either alone or in combination with less than 10 percent coal/solid fossil fuel, and less than 10 percent biomass/bio-based solid fuel on an annual heat input basis, and less than 10 percent no liquid fuels on an annual heat input basis with the exception of liquid fuels burned for periodic testing not to exceed a combined total of 48 hours during any calendar year, or during periods of gas curtailment or gas supply interruptions.

Alternative 2:

Unit designed to burn gas 2 (other) subcategory includes any boiler or process heater that is not in the unit designed to burn gas 1 subcategory and burns any gaseous fuels either alone or in combination with less than 10 percent coal/solid fossil fuel, less than 10 percent biomass/bio-based solid fuel, and less than 10 percent liquid fuels on an annual heat input basis any other “unit designed to burn” subcategory. [Note: or specifically list all of the other “unit designed to burn” subcategories].

Response: The EPA agrees with the commenter and has clarified the definition of unit designed to burn gas 2 (other) subcategory. It was the EPA's intent in the proposed rule to require units

firing liquid fuels in combination with gas 1 fuels that did not meet the thresholds for liquid fuel allowed in the unit designed to burn gas 1 subcategory to be captured in the unit designed to burn liquid subcategory.

For clarification, the unit designed to burn gas 2 (other) subcategory definition has been revised to reflect that the units in this subcategory do not burn liquid fuels, with the exception of liquid fuels burned under the testing, curtailment, and gas supply emergency thresholds. The definition has been revised to read: "Unit designed to burn gas 2 (other) subcategory includes any boiler or process heater that is not in the unit designed to burn gas 1 subcategory and burns any gaseous fuels either alone or in combination with less than 10 percent coal/solid fossil fuel, and less than 10 percent biomass/bio-based solid fuel on an annual heat input basis, and no liquid fuels. Gaseous fuel boilers and process heaters that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year, are included in this definition. Gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply emergencies of any duration are also included in this definition." This definition is consistent with the unit designed to burn gas 1 and unit designed to burn liquid subcategories.

Commenter Name: Felix Mestey, on behalf of Donald R. Schregardus

Commenter Affiliation: Clean Air Act Services Steering Committee, Department of Defense (DoD)

Document Control Number: EPA-HQ-OAR-2002-0058-3427

Comment Excerpt Number: 10

Comment: The definition of energy assessment will be different in the major and area source rules if the terms “boilers” and “process heaters” are used and if the rule table references are included. The following shows how the definition in the major source rule should be changed for consistency. This also reflects our conclusion that it is not necessary to limit the term to a table in the rule because the term is used throughout the rule.

Energy assessment means the following ~~only as this term is used in Table 3 to for the~~ emission units covered by this subpart.:

(1) ~~The~~ Energy assessment for facilities with affected boilers and process heaters using less than 0.3 trillion Btu (TBtu) per year heat input will be 8 technical labor hours in length maximum, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s) and any on-site energy use system(s) accounting for at least 50 percent of the energy output will be evaluated to identify energy savings opportunities, within the limit of performing an 8-hour energy assessment.

(2) ~~The~~ Energy assessment for facilities with affected boilers and process heaters using 0.3 to 1.0 ~~trillion Btu per~~ TBtu/year will be 24 technical labor hours in length maximum, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s) and any on-site energy use system(s) accounting for at least 33 percent of the energy output will be evaluated to identify energy savings opportunities, within the limit of performing a 24-hour energy assessment.

(3) ~~It~~The ~~E~~energy assessment for facilities with affected boilers and process heaters using greater than 1.0 ~~trillion Btu per~~ TBtu/year, the boiler system(s) and any on-site energy use system(s) accounting for at least 20 percent of the energy output will be evaluated to identify energy savings opportunities.

Response: EPA appreciates the commenter's input. The definition of Energy assessment has been revised accordingly for consistency between the major and area source rules.

Commenter Name: Samuel H. Bruntz
Commenter Affiliation: Alcoa Power Generating, Inc.
Document Control Number: EPA-HQ-OAR-2002-0058-3755-A1
Comment Excerpt Number: 15

Comment: Clarify the Definition of Metal Process Unit.

Metal process furnaces are a subset of "*Process Heaters*" covered by the rule. However, the current definition for *Metal process furnace* could be misinterpreted more broadly to also include furnaces that transfer heat directly to process material and are potentially regulated under another NESHAP. Alcoa- Warrick thus requests that EPA clarify the existing definition as follows:

Metal process furnaces are a subset of process heaters that includes natural gas-fired annealing furnaces, preheat furnaces, reheat furnaces, aging furnaces, heat treat furnaces, and homogenizing furnaces.

Response: EPA appreciates the commenter's input. The definition of Metal Process furnaces has been revised accordingly.

Commenter Name: M.L. Steele
Commenter Affiliation: CraftMaster Manufacturing, Inc.
Document Control Number: EPA-HQ-OAR-2002-0058-3814-A1
Comment Excerpt Number: 19

Comment: §63.7575 Definition of "other combustor". It is unclear why "pulverized coal" is included in the list of combustors that are not "other combustors". The "other combustor" designation applies only to biomass-fired units.

Response: Within the inventory database there are units listed as "pulverized coal" that are listed as combusting biomass.

Commenter Name: M.L. Steele
Commenter Affiliation: CraftMaster Manufacturing, Inc.
Document Control Number: EPA-HQ-OAR-2002-0058-3814-A1
Comment Excerpt Number: 23

Comment: §63.7575 Definitions. "Start-up" should be in italics print.

Response: EPA appreciates the commenter's input. The definition of "Start-up" has been revised accordingly.

Commenter Name: Russell A. Wozniak

Commenter Affiliation: The Dow Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3449-A1

Comment Excerpt Number: 3

Comment: Dow supports EPA's revised definition of Other Gas 1 Fuel.

Dow supports EPA's proposed revised definition of "Other gas 1 fuel" which means a gaseous fuel that is not natural gas or refinery gas and does not exceed the maximum concentration of 40 micrograms per cubic meters of mercury.

Response: The EPA thanks the commenter for their support.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 173

Comment: In the definition of "other gas 1 fuel," "the" should be "a".

Response: The EPA agrees. The definition of "other gas 1 fuel" has been revised as follows: "Other gas 1 fuel means a gaseous fuel that is not natural gas or refinery gas and does not exceed a maximum concentration of 40 micrograms/cubic meters of mercury."

Commenter Name: David L. Meeker

Commenter Affiliation: National Renderers Association (NRA)

Document Control Number: EPA-HQ-OAR-2002-0058-3476-A1

Comment Excerpt Number: 3

Comment: EPA again changed the liquid fuel definition in the December 23, 2011 reconsidered NESHAP Subpart JJJJJ to include the addition of vegetable oil.

Liquid fuel includes, but is not limited to, distillate oil, residual oil, any form of liquid fuel derived from petroleum, on-spec used oil, liquid biofuels, biodiesel, and vegetable oil.

As noted above, the addition of liquid biofuels was included in NESHAP Subpart JJJJJ liquid fuel definition previous to this reconsideration, per the comment submitted by Darling International Inc. (NRA member).

The December 23, 2011 reconsidered NESHAP Subpart DDDDD included the addition of subcategories for light liquid and heavy liquid fuels in §63.7575.

Light liquid includes distillate oil, biodiesel or vegetable oil.

However, EPA clearly took an "easy way" out by throwing processed fats in with the liquid fuel definition in NESHAP Subpart JJJJJ and assumed intended inclusion of light liquid definition that was unexpected and unintended by the NRA, without fully vetting the impact on the liquid fuel regulations, or the impact on processed fat-fired units. EPA has acknowledged acting in haste to finalize these regulations by the Court-imposed deadline.⁶

The proposed definition of "liquid fuel" is fundamentally similar in both NESHAP Subpart JJJJJ (75 FR 31931) and NESHAP Subpart DDDDD (75 FR 32064), specifically delineating "distillate oil, residual oil, on-spec used oil, biodiesel, and vegetable oil" in each definition. EPA has not indicated that the subsequent inclusion of "liquid biofuels" to the definition of "liquid fuel" was intentional for NESHAP Subpart JJJJJ only. For the purposes of this comments letter, the NRA assumes that EPA intended for liquid biofuels to also be considered a "light liquid" as defined under §63.7575 in the reconsidered rule.

[Footnote 6: Court ordered EPA to issue the final rule by February 21, 2011.]

Response: The definition of "Liquid fuel" as far back as the 2004 Boiler MACT (since vacated) has contained the phrase ""includes, but is not limited to," The definitions generally listed the the most prevalent ones. Based on comments the definition has been revised to add certain liquid fuel to clarify some applicability or implementation issue. In any case, the source category has always included, but was not limited to, boilers fired by mixed or other fuels.

Commenter Name: Arthur N. Marin

Commenter Affiliation: Northeast States for Coordinated Air Use Management (NESCAUM)

Document Control Number: EPA-HQ-OAR-2002-0058-3506-A1

Comment Excerpt Number: 1

Comment: There are inconsistencies between the Area Source Rule, Major Source Rule, and CISWI Rule definitions. The EPA is proposing several definitions in the area source boiler rule, major source boiler rule (both under consideration separately), and CISWI rule that are designed to clarify the applicable fuels under the appropriate section of the Clean Air Act (CAA) regulating a combustion device (i.e., Section 112 or 129). NESCAUM notes that there are inconsistencies between the area source rule, major source rule, and CISWI rule, and requests that the EPA harmonize the definitions between the rules so there is no ambiguity as to which rule a source is subject. For example, the following definitions for liquid fuel are inconsistent between the three rules:

1. In the proposed area source boiler rule, liquid fuel is defined as follows:

Liquid fuel includes, but is not limited to, distillate oil, residual oil, any form of liquid fuel derived from petroleum, on-spec used oil, liquid biofuels, biodiesel, and vegetable oil.

2. In the proposed major source boiler rule, liquid fuel is defined as follows:

Liquid fuel includes, but is not limited to, distillate oil, residual oil, onspec used oil, biodiesel and vegetable oil.

3. Under the CISWI and NHSM rules, liquid fuel is classified under “traditional fuel” as follows (excerpted as noted):

Traditional fuels means materials that are produced as fuels and are unused products that have not been discarded and therefore, are not solid wastes, including: (1) ... fossil fuels (e.g., coal, oil and natural gas)...; and (2) alternative fuels developed from virgin materials that can now be used as fuel products, including used oil which meets the specifications outlined in 40 CFR 279.11....

NESCAUM understands that all of these definitions are intended to encompass all non-waste liquid fuels that the EPA has deemed to be traditional fuels when burned in a combustion device and should be regulated under Section 112. NESCAUM recommends that the definitions be harmonized to all say the same thing (i.e., reference 40 CFR 279.11 for defining used oil) to the extent possible and list the same examples (i.e., list liquid biofuels and vegetable oil in all three definitions).

Response: See the response to comment EPA-HQ-OAR-2002-0058-3476-A1, excerpt 3 for definition of liquid fuels in the major source rule. Definition of traditional fuels in the CISWI and NHSM rules are outside the scope of this comment response document. To the extent that this comment was submitted to the dockets for CISWI and/or NHSM it will be addressed in those response to comment documents.

Commenter Name: Jessica Bridges

Commenter Affiliation: United States Clean Heat & Power Association (USCHPA)

Document Control Number: EPA-HQ-OAR-2002-0058-3501-A1

Comment Excerpt Number: 26

Comment: 40 CFR 63.7575, Revise the definition of “liquid fuel” to include vegetable oil. This is appropriate.

Response: The EPA thanks the commenter for their support.

Commenter Name: Jessica Bridges

Commenter Affiliation: United States Clean Heat & Power Association (USCHPA)

Document Control Number: EPA-HQ-OAR-2002-0058-3501-A1

Comment Excerpt Number: 34

Comment: 40 CFR 63.7575, The addition of “biodiesel” to the definition of liquid fuels is appropriate.

Response: The EPA thanks the commenter for their support.

Commenter Name: Jessica Bridges

Commenter Affiliation: United States Clean Heat & Power Association (USCHPA)

Document Control Number: EPA-HQ-OAR-2002-0058-3501-A1

Comment Excerpt Number: 35

Comment: 40 CFR 63.7575, The addition of “vegetable oil” to the definition of liquid fuels is appropriate.

Response: The EPA thanks the commenter for their support.

Commenter Name: Jessica Bridges

Commenter Affiliation: United States Clean Heat & Power Association (USCHPA)

Document Control Number: EPA-HQ-OAR-2002-0058-3501-A1

Comment Excerpt Number: 31

Comment: 40 CFR 63.7575, The new definition of “30-day rolling average” is appropriate.

Response: The EPA thanks the commenter for their support.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 166

Comment: The definition of "annual heat input" is unclear because compliance demonstrations are an ongoing requirement. The definition should be revised as follows:

Annual heat input means the heat input for the 12 months preceding the **initial** compliance demonstration.

If it was intended that annual heat input be determined every year, the definition should be on a calendar basis and compliance time provisions need to be added where new requirements are triggered by changes in the annual heat input value (i.e., a BPH changes subcategory).

Response: We disagree that the definition be revised to include "initial" because that would imply "once in always in" that subcategory. The subcategory are based on the annual heat input prior to the compliance demonstration.

Commenter Name: Jessica Bridges

Commenter Affiliation: United States Clean Heat & Power Association (USCHPA)

Document Control Number: EPA-HQ-OAR-2002-0058-3501-A1

Comment Excerpt Number: 32

Comment: 40 CFR 63.7575, The new definition of “average annual heat input rate” is appropriate.

Response: The EPA thanks the commenter for their support.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 135

Comment: Since there is no logical reason to single out specific subtypes of water heaters for applicability within the universe of water heaters that are not part of the source category, we recommend that EPA revise the water heater definition to exclude the capacity limitation. Including water heaters within the applicability of the rule would also impose very high regulatory compliance costs on users and regulatory authorities for units with insignificant emissions.

EPA attempted to address this concern by adding the following sentence to the definition in the proposed rule: "Hot water boilers (i.e., not generating steam) combusting gaseous or liquid fuel with a heat input capacity of less than 1.6 million Btu per hour are included in this definition." This addition has only created additional confusion as to what types of units meet this definition. Therefore, we recommend EPA revise the definition of hot water heater to read as follows:

Hot water heater means a closed vessel in which water is heated by combustion of gaseous or liquid fuel and is withdrawn for use external to the vessel at pressures not exceeding 160 pounds per square inch gauge (psig), including the apparatus by which the heat is generated and all controls and devices necessary to prevent water temperatures from exceeding 250°F (121°C) at or near the heater outlet.

Alternatively, EPA should reword the definition to clarify that units that are EITHER less than 120 gallons OR less than 1.6 MMBtu/hr meet the definition of a water heater, as follows:

Hot water heater means a closed vessel with a capacity of no more than 120 U.S. gallons or a heat input capacity of no more than 1.6 million Btu per hour in which water is heated by combustion of gaseous or liquid fuel and is withdrawn for use external to the vessel at pressures not exceeding 160 psig, including the apparatus by which the heat is generated and all controls and devices necessary to prevent water temperatures from exceeding 210 degrees Fahrenheit (99 degrees Celsius). Hot water heater also means a tankless unit that provides on demand hot water.

Response: Based on various comments, the definition of "Hot water heater" has been revised to read:

Hot water heater means a closed vessel with a capacity of no more than 120 U.S. gallons in which water is heated by combustion of gaseous, liquid, or biomass/bio-based solid fuel and is withdrawn for use external to the vessel. Hot water boilers (i.e., not generating steam) combusting gaseous, liquid, or biomass fuel with a heat input capacity of less than 1.6 million Btu per hour are included in this definition. The 120 U.S. gallon capacity threshold to be considered a hot water heater is independent of the 1.6 MMBtu/hr heat input capacity threshold for hot water boilers. Hot water heater also means a tankless unit that provides on demand hot water.

Commenter Name: Arthur N. Marin

Commenter Affiliation: Northeast States for Coordinated Air Use Management (NESCAUM)

Document Control Number: EPA-HQ-OAR-2002-0058-3506-A1

Comment Excerpt Number: 25

Comment: In the proposed definition of hot water heaters discussed earlier, the EPA lists “gaseous or liquid fuel” but not biomass. NESCAUM suggests that the definition also include biomass-fueled units. Without that exclusion, some very small units in the Northeast will fail to be exempted from the rule despite their negligible impact on HAP emissions. NESCAUM recommends the following revision to the definition:

Hot water heater means a closed vessel with a capacity of no more than 120 U.S. gallons in which water is heated by combustion of gaseous, liquid, or biomass fuel and hot water is withdrawn for use external to the vessel. Hot water boilers (i.e., not generating steam) combusting gaseous, liquid, or biomass fuel with a heat input capacity of less than 1.6 million Btu per hour are included in this definition.

Response: EPA appreciates the commenter's input. The definition of "Hot water heater" has been revised accordingly to include biomass.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 134

Comment: We agree that hot water heaters should be exempted from the rule as proposed (63.7491).

We agree that there should be some objective standard to distinguish hot water heaters from steam generators. An easily verifiable and rational method for distinction is on a mechanical design basis. Water heaters are intended generally for personal and domestic use, as well as for local heating purposes, and not for industrial purposes. All types of industrial, commercial, and institutional facilities incorporate individual water heaters throughout the facility, particularly in separated locations where use of a common steam or heating system is not economically justified for the low energy input required. By their application, water heaters operate on a very cyclic and inconsistent basis, with typically very low resultant HAP emissions. Imposing a limitation on water volume capacity is arbitrary and neuters the point that these units are not listed in the source category regardless of size.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 135.

Commenter Name: Tangela Niemann

Commenter Affiliation: Texas Commission on Environmental Quality (TCEQ)

Document Control Number: EPA-HQ-OAR-2002-0058-3594-A3

Comment Excerpt Number: 13

Comment: The definition for *hot water heater* in §63.7575 includes provisions regarding maximum pressure and temperature conditions for a unit to qualify as a hot water heater; however, the EPA has proposed to remove the same provisions from the definition of a hot water

heater in §63.11237 for 40 CFR 63 Subpart JJJJJ (76 FR 80547). The EPA has not provided any rationale why a more specific definition is needed for major sources under 40 CFR 63 Subpart DDDDD than for area sources under 40 CFR 63 Subpart JJJJJ. The definition of a *hot water heater* should be consistent between the two rules. However, the TCEQ recommends keeping the provision in §63.7575 that includes tankless water heaters in the definition of *hot water heater* in 40 CFR 63, Subpart DDDDD. In separate comments submitted concurrently on the EPA's proposed revisions to 40 CFR 63 Subpart JJJJJ, the TCEQ suggested that tankless water heaters should be included in the proposed revised definition of *hot water heater* in §63.11237. Additionally, the EPA needs to clarify whether the requirement that hot water boilers must be less than 1.6 MMBtu/hr heat input capacity threshold to qualify as a hot water heater is considered independent of the 120 gallon capacity threshold.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 135. Comments and edits related to the definition of hot water heaters in the area source rule will be addressed in that separate rulemaking docket.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 151

Comment: THE HOT WATER HEATER DEFINITION SHOULD BE REVISED

ACC agrees that hot water heaters should be exempted from this rule as indicated in § 63.7491. However, EPA proposes to define hot water heater as follows:

ACC concurs that there should be some objective standard to distinguish hot water heaters from steam generators. An easily verifiable, and rational method, for distinction is on a mechanical design basis. The ASME Code, Section IV- Rules for Construction of Heating Boilers, is applicable to hot water heating boilers and is, in our opinion, the standard that should be used to define a hot water heater consistent with industry standards. The ASME Code, Section IV is applicable to: —(a) steam boilers for operation at pressures not exceeding 15 psi; (b) hot water heating boilers and hot water supply boilers for operating at pressures not exceeding 160 psi and/or temperatures not exceeding 250°F, at or near the boiler outlet."

Response: See the response to comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 135.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 152

Comment: ACC does support the inclusion of the heat input capacity limitation and inclusion of tankless water heaters in the definition, and recommends that EPA revise the definition of hot water heater to read as follows:

Hot water heater means a closed vessel in which water is heated by combustion of gaseous or liquid fuel and is withdrawn for use external to the vessel at pressures not exceeding 160 pounds per square inch gauge (psig), including the apparatus by which the heat is generated and all controls and devices necessary to prevent water temperatures from exceeding 250°F (121°C) at or near the heater outlet. Hot water boilers (i.e., not generating steam) combusting gaseous or liquid fuel with a heat input capacity of less than 1.6 million Btu per hour are included in this definition. Hot water heater also means a tankless unit that provides on demand hot water.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 135.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 153

Comment: Alternatively, if EPA feels size thresholds are warranted, ACC suggests reorganizing the proposed definition for clarity. EPA should reword the definition of hot water heater to make it clear that a hot water heater is "a closed vessel with a capacity of no more than 120 U.S. gallons or with heat input no more than 1.6 million Btu/hr and is withdrawn for use external to the vessel at pressures not exceeding 160 psig, including the apparatus by which the heat is generated and all controls and devices necessary to prevent water temperatures from exceeding 210 degrees Fahrenheit (99 degrees Celsius). Hot water heater also means a tankless unit that provides on demand hot water."

Response: See the response to comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 135.

Commenter Name: Russell A. Wozniak

Commenter Affiliation: The Dow Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3449-A1

Comment Excerpt Number: 34

Comment: Dow supports EPA's proposed expanded definition of the term hot water heater. Specifically, Dow supports EPA's proposal to include hot water boilers (i.e., not generating steam) combusting gas or liquid fuel with a heat input capacity of less than 1.6 million Btu per hour. These are insignificant sources that should be treated as a hot water heater for the purpose of this rule.

Response: The EPA thanks the commenter for their support.

Commenter Name: David A. Buff, Golder Associates Inc.

Commenter Affiliation: Florida Sugar Industry (FSI)

Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1

Comment Excerpt Number: 9

Comment: The FSI agrees with the proposed change to the definition of hybrid suspension grate boilers, which now includes the following sentence: "The fuel combusted in these units exceed[s] a moisture content of 40 percent on an as-fired basis." Section 63.7575; 76 F.R.80652.

This value is appropriate because the moisture content of bagasse typically ranges from approximately 48 percent to 55 percent. However, hybrid suspension grate boilers also fire other fuels, such as No. 6 fuel oil, as supplemental fuel or for startup, shutdown and malfunction. Accordingly, this definition should be revised to read: "The *biomass* fuel combusted in these units exceeds a moisture content of 40 percent on an as-fired basis."

Response: The EPA agrees with the commenter. The definition of hybrid suspension grate boilers has been revised accordingly.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 130

Comment: As quoted immediately above, the Gas 2 subcategory is defined to permit a unit to burn up to "10 percent liquid fuels on an annual heat input basis," and we have recommended that EPA make a conforming change to the definition of the Gas 1 subcategory. EPA has proposed to divide the "unit designed to burn liquid" subcategory into two sub-subcategories, but it has failed to make an important and necessary technical correction to the definition of that subcategory. As SOCMA pointed out in its comments on the June 2010 proposed rule,⁵⁷ the "unit designed to burn liquid subcategory" is defined to include "any boiler or process heater that burns *any* liquid . . ." § 63.7575 (emphasis added). The definition goes on to allow gaseous fuel boilers to burn liquids for periodic testing, maintenance and operator training (for up to 48 hours) and for periods of gas curtailment or supply emergencies, *id.*, but it does not contain a generic exemption for gaseous fuel boilers that burn less than 10% liquids on an annual heat input basis. As a result, a Gas 2 unit that burned 5% liquid fuels would be included in *both* the Gas 2 and liquid subcategories. A Gas 1 unit redefined as we propose would face the same problem. Accordingly, as EPA makes other technical corrections to the current rule, it should also revise the definition of the unit designed to burn liquid subcategory to provide that it "includes any boiler or process heater that burns more than 10 percent liquid fuel . . ." ⁵⁸

[Footnote 57: See SOCMA comments (EPA-HQ-OAR-2002-058-2926), at 3.]

[Footnote 58: With that change, the definition might no longer need the exemption for testing, maintenance and training. It probably should maintain the exemption for curtailment and supply emergencies, however.]

Response: See the response to comment EPA-HQ-OAR-2002-0058-3427, excerpt 8.

Commenter Name: Felix Mestey, on behalf of Donald R. Schregardus

Commenter Affiliation: Clean Air Act Services Steering Committee, Department of Defense (DoD)

Document Control Number: EPA-HQ-OAR-2002-0058-3427

Comment Excerpt Number: 9

Comment: Several definitions in the area source rule differ from the definitions in the major source rule. Some differences are appropriate due to the differences in the scope of the rules and the subcategories used. However, in many cases the definitions could and should be identical.

Fuel type means each category of fuels that share a common name or classification. Examples include, but are not limited to, bituminous coal, sub-bituminous coal, lignite, anthracite, biomass, distillate oil, residual oil. Individual fuel types received from different suppliers are not considered new fuel types.

Response: The EPA appreciates the commenter's input. Definitions, as appropriate, have been revised accordingly for consistency between the major and area source rules.

Commenter Name: Felix Mestey, on behalf of Donald R. Schregardus

Commenter Affiliation: Clean Air Act Services Steering Committee, Department of Defense (DoD)

Document Control Number: EPA-HQ-OAR-2002-0058-3427

Comment Excerpt Number: 11

Comment: The area source rule has separate definitions for commercial boiler and institutional boiler. The major source rule has a single definition for commercial/institutional boiler. It does not matter which approach is used, but these definitions could be the same in both rules. Currently the definitions in the area source rule contain more examples of commercial and institutional establishments. At a minimum, the examples should be consistent and the combined definition in the major source rule could be revised as follows. *Commercial/institutional boiler means a boiler used in commercial establishments or institutional establishments such as medical centers, nursing homes, research centers, institutions of higher education, elementary and secondary schools, libraries, religious establishments, and governmental buildings, hotels, restaurants, and laundries to provide steam and/or hot water.*

EPA should consider either a) replacing the combined definition for commercial/institutional boiler in the major source rule with the separate definitions used in the area source rule, or b) replacing the separate definitions in the area source rule with the revised version of the combined definition shown above.

Response: The EPA has revised the definition of commercial/institutional boiler for consistency with the area source rule. Revisions to the definitions of commercial boiler and institutional boiler in the area source rule are discussed in a separate response to comment document (see Docket ID. No EPA-HQ-OAR-2006-0790) for the area source rule.

Commenter Name: Felix Mestey, on behalf of Donald R. Schregardus

Commenter Affiliation: Clean Air Act Services Steering Committee, Department of Defense (DoD)

Document Control Number: EPA-HQ-OAR-2002-0058-3427

Comment Excerpt Number: 12

Comment: EPA should also change the following definitions to reflect the change to the term “periods of natural gas curtailment and gas supply emergencies” to “periods of gas curtailment and gas supply interruption.”

Unit designed to burn gas 1 subcategory includes any boiler or process heater that burns only natural gas, refinery gas, and/or other gas 1 fuels; with the exception of liquid fuels burned for periodic testing not to exceed a combined total of 48 hours during any calendar year, or during periods of gas curtailment and gas supply emergenciesinterruption.

Unit designed to burn liquid subcategory includes any boiler or process heater that burns any liquid fuel, but less than 10 percent coal/solid fossil fuel and less than 10 percent biomass/bio-based solid fuel on an annual heat input basis, either alone or in combination with gaseous fuels. Gaseous fuel boilers and process heaters that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year or during periods of maintenance, operator training, or testing of liquid fuel, not to exceed a combined total of 48 hours during any calendar year are not included in this definition. Gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply emergenciesinterruption of any duration are also not included in this definition.

Response: The EPA appreciates the commenter's input. The definitions have been revised accordingly for consistency.

Commenter Name: Arthur N. Marin

Commenter Affiliation: Northeast States for Coordinated Air Use Management (NESCAUM)

Document Control Number: EPA-HQ-OAR-2002-0058-3506-A1

Comment Excerpt Number: 11

Comment: NESCAUM agrees that temporary boilers should be exempted from both the major and area source boiler rules. Subjecting these units to strict requirements beyond management practices is impractical. NESCAUM supports the establishment of a 12 month threshold, above which a unit may no longer be considered temporary. Many commercial buildings that use temporary boilers during construction, however, require more than 12 months to complete construction, and as such, NESCAUM recommends that the EPA amend the definition of temporary boilers to allow owners or operators of a facility to petition for an extension. NESCAUM believes this process is needed to allow proper flexibility within the rule so as not to require stringent controls on units that are temporary. NESCAUM specifically recommends that the second condition in the definition of a temporary boiler be changed as follows:

(2) The boiler or a replacement remains at a location for more than 12 consecutive months, unless the regulating agency approves an extension. An extension may be granted by the regulating agency upon petition by the owner or operator of a unit specifying the basis for such a request. Any temporary boiler that replaces a temporary boiler at a location and performs the same or similar function will be included in calculating the consecutive time period.

Response: The EPA appreciates the commenter's input. The definition has been revised accordingly.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 175

Comment: In the "temporary boiler" definition, paragraph (2) excludes a boiler or a replacement that "remains at a location for more than 12 consecutive months." And further specifies that "Any temporary boiler that replaces a temporary boiler at a location and performs the same or similar function will be included in calculating the consecutive time period."

The second sentence language creates a problem because there is no time period associated with the replacement. It is not unusual for a temporary boiler to be used for short periods during turnarounds that recur several years apart. Under the proposal, these boilers would not be considered temporary, because each boiler replaces the previous one and performs the same function, even though there is a multi-year gap between the occurrences. We believe that replacements that occur after a gap of at least one year should not be considered consecutive for the purposes of this definition and the language of paragraph (2) should be revised to reflect that situation.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3506-A1, excerpt 11.

Commenter Name: Shawn Good

Commenter Affiliation: Pennsylvania Chamber of Business and Industry

Document Control Number: EPA-HQ-OAR-2002-0058-3671-A2

Comment Excerpt Number: 5

Comment: EPA proposes to exempt temporary boilers, as was done in the final rule for major sources. We agree that temporary boilers should be exempted from both rules if they are to be exempted from any. However, we believe that the definition of temporary boilers should include emergency use boilers or safety related boilers. Such consideration has been provided for other MACT source categories as IC engines. Further, EPA should clarify whether "temporary" means use for start-up as well as back-up purposes.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3506-A1, excerpt 11. The term "temporary," to clarify, refers to portable/rental boilers.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 138

Comment: The proposed definition of "daily block average" requires that monitoring results from periods of startup and shutdown be included in the average.

"Daily block average means the arithmetic mean of all valid emission concentrations or parameter levels recorded when a unit is operating measured over the 24-hour period from 12 a.m. (midnight) to 12 a.m. (midnight)."

A startup and shutdown period exception must be added to the definition of "daily block average" since sources are exempt from meeting emission standards and opacity and operating parameter limits during these periods.

This same exemption must be added to the definition of "30-day rolling average." EPA should specify that the 30-day rolling average includes the previous 720 hours of valid operating data. Valid operating data excludes hours during startup and shutdown as well as unit down time.

Response: The EPA agrees with the commenter and has revised the definitions of daily block average and 30-day rolling average accordingly. The definition of daily block average has been clarified as follows:

Daily block average means the arithmetic mean of all valid emission concentrations or parameter levels recorded when a unit is operating measured over the 24-hour period from 12 am (midnight) to 12 am (midnight), except for periods of startup and shutdown or downtime.

The definition of 30-day rolling average has been clarified as follows:

30-day rolling average means the arithmetic mean of the previous 720 hours of valid operating data. Valid data excludes hours during startup and shutdown, data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities, and periods when this unit is not operating. The 720 hours should be consecutive, but not necessarily continuous if operations were intermittent.

Commenter Name: Dean C. DeLorey

Commenter Affiliation: The Amalgamated Sugar Company LLC (TASCO)

Document Control Number: EPA-HQ-OAR-2002-0058-3522-A1

Comment Excerpt Number: 18

Comment: The proposed rule describes TSM as the combination of the following metallic hazardous air pollutants: As, Be, Cd, Cr, Pb, Mn, Ni, and Se. However, combination is not defined. Please clarify the definition of TSM including the term "combination".

Response: It is the EPA's intent that total selected metals (TSM) includes the aggregate of the identified individual metallic hazardous air pollutants. Therefore, we have revised the definition of TSM as follows:

Total selected metals means the sum of the following metallic hazardous air pollutants: arsenic, beryllium, cadmium, chromium, lead, manganese, nickel and selenium.

Commenter Name: Robin Mills Ridgway

Commenter Affiliation: Purdue University

Document Control Number: EPA-HQ-OAR-2002-0058-3668-A2

Comment Excerpt Number: 14

Comment: In §63.7575, "Dry Scrubber" is defined to include sorbent used in fluidized bed boilers. Elsewhere in the proposed rule, EPA uses the terms "sorbent injection." Purdue asks EPA to confirm that the use of in furnace limestone in CFB boilers is indeed "sorbent injection" as well as a "dry scrubber" in the proposed Boiler MACT.

Response: The EPA has revised the definition of Minimum sorbent injection rate to clarify that the use of in furnace limestone in a circulating fluidized bed boiler would be considered "sorbent injection" for the purposes of the final rule. See the response to comment EPA-HQ-OAR-2002-0058-3674-A, excerpt 11 for more information.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 38

Comment: The proposed definition of "unit designed to burn gas 1 subcategory" provides for a liquids exception for "periodic testing not to exceed a combined total of 48 hours during any calendar year." However, the same exception in the "unit designed to burn liquid subcategory" is referenced and described as "Gaseous fuel boilers and process heaters that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year." Because operator training and maintenance are important reasons for occasionally having to fire liquids on a BPH that primarily fires gas 1, the 48 hour exception in the gas 1 subcategory definition should be revised to match the description in the liquids subcategory definition.

The proposed "boiler" definition includes the production of hot water. The proposed "process heater" definition includes the production of hot water to be used as a process heat transfer material. Thus, units that produce hot water as a process heat transfer medium are both boilers and process heaters. The boiler definition should be revised to exclude the production of hot water for use as a process heat transfer medium.

Response: The EPA acknowledges that boilers or process heaters that fall into the unit designed to burn gas 1 subcategory may have a need to burn liquid fuels for operator training or maintenance. Therefore, the subcategory definition has been updated as follows:

Unit designed to burn gas 2 (other) subcategory includes any boiler or process heater that is not in the unit designed to burn gas 1 subcategory and burns any gaseous fuels either alone or in combination with less than 10 percent coal/solid fossil fuel, and less than 10 percent biomass/bio-based solid fuel on an annual heat input basis, and no liquid fuels. Gaseous fuel boilers and process heaters that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year, are included in this definition. Gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply emergencies of any duration are also included in this definition.

This definition is consistent with other subcategory definitions under the final subpart. Additionally, the EPA agrees with the commenter that the definitions of boiler and process heater requires clarification for units producing hot water as a process heat transfer material but we disagree that the definition of boiler should be revised. The definition of process heater has been updated as follows:

Process heater means an enclosed device using controlled flame, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material (e.g., glycol or a mixture of glycol and water) for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not come into direct contact with process materials. A device combusting solid waste, as defined in §241.3 of this chapter, is not a process heater unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Process heaters do not include units used for comfort heat or space heat, food preparation for on-site consumption, or autoclaves. Waste heat process heaters are excluded from this definition.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 53

Comment: Tune-up is defined in proposed §63.7575 as "adjustments made to a boiler in accordance with procedures supplied by the manufacturer (or an approved specialist) to optimize the combustion efficiency." The term "approved specialist" is undefined. It is also unclear whose approval is required. As we discuss elsewhere, most BPH are not "manufactured" and thus there are no applicable manufacturer's procedures. Therefore most of the tune-up procedures will be developed by specialists. It would impose unreasonable burdens to require approval of this multitude of specialists, since they will be numerous, frequently changing, and there is no objective set of criteria for evaluating a person's adequacy. The "approval" requirement should be deleted from the tune-up definition.

Response: The EPA acknowledges the commenter's concerns. However, the EPA's intent in the proposed rule was to require owners and operators of units required to perform an annual tune-up to meet the requirements specified in 40 CFR 63.7540(a)(10). Therefore, the definition of tune-up has been revised to read, "Tune-up means adjustments made to a boiler or process heater in accordance with the procedures outlined in §63.7540(a)(10)."

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 54

Comment: The tune-up definition refers to boilers and not process heaters. If, as indicated elsewhere, EPA intends to apply the tune-up requirements to process heaters, that should be indicated in the definition.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 53. By changing the definition to be based on the required procedures, the definition applies to both boilers and process heaters, as originally intended by the Agency.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 52

Comment: The definition of tune-up in proposed §63.7575 describes "adjustments made ... to optimize combustion efficiency." While we believe that is an appropriate definition, it does not match the requirements specified in proposed §63.7540(a)(10). That paragraph specifies six tune-up requirements that require specific inspections, that CO production is optimized, and that specific records be maintained and submitted on request. This problem was noted in the finalization of the March 21, 2011 BPH NESHAP and the proposed definition of tune-up was not finalized in order to remove this conflict. EPA stated in the final rule preamble "The definition of "Tune-up" was removed from 40 CFR 63.7575 because all of the requirements for a tune-up are provided in the rule language at 40 CFR 63.7540(a)(10), making the definition unnecessary." 15 We recommend the same action here. EPA should not finalize the proposed definition of "tune-up". Should the Agency opt to finalize a tune-up definition 1) a specific reference to the required §63.7540(a)(10) elements should be added, 2) the reference to optimizing combustion should be removed, since that is not an element in the (a)(10) requirements and 3) the following 2 items should be addressed. [Footnote 15: 76 Fed. Reg. 15620 (March 21, 2011)]

Response: See the responses to comments EPA-HQ-OAR-2002-0058-3677-A2, excerpt 53 and excerpt 54.

Commenter Name: Kevin Bloomer

Commenter Affiliation: Westlake Chemical Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3535-A2

Comment Excerpt Number: 2

Comment: Westlake seeks clarification that the proposed definition of *distillate oil*¹ is the same as the one in 40 CFR 60, Subpart Db.

[Footnote]

(1) See 40 CFR §60.41b - *Distillate oil* means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see § 60.17) or diesel fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see § 60.17).

Response: In order to maintain consistency for boilers and process heaters that may be subject to various subparts under 40 CFR part 60, 61, 63, and 65, we have revised the definition of

distillate oil to be consistent with 40 CFR 60, Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 176

Comment: The definition of "residual oil" includes #4 fuel oil. In other EPA rules (e.g., GHG reporting rule), #4 fuel oil was defined as a distillate fuel. In order to maintain some consistency, we recommend striking "#4" from the residual oil definition. Doing so would still allow #4 to be considered a "heavy fuel," but eliminate the inconsistency between rules.

Response: The EPA acknowledges the commenter's concerns but disagrees with the proposed changes. The GHG Reporting Rule requires reporting of greenhouse gas data to inform future regulatory decisions, but does not provide emission standards for boilers and process heaters. In order to maintain consistency for boilers and process heaters that may be subject to emission standards under various subparts under 40 CFR part 60, 61, 63, and 65, we have revised the definition of residual oil to be consistent with 40 CFR 60, Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units. The definition has been revised as follows:

Residual oil means crude oil, fuel oil numbers 1 and 2 that have a nitrogen content greater than 0.05 weight percent, and all fuel oil numbers 4, 5, and 6, as defined by the American Society of Testing and Materials in ASTM D396–10 (incorporated by reference, see §63.14(b)).

Commenter Name: Kevin Bloomer

Commenter Affiliation: Westlake Chemical Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3535-A2

Comment Excerpt Number: 3

Comment: Westlake requests EPA to make the definition of the term *residual oil*² be the same as the definition in 40 CFR 60, Subpart Db in order to make these two rules impacting ICI boilers consistent with one another.

[Footnote]

(2) See 40 CFR §60.41b - *Residual oil* means crude oil, fuel oil numbers 1 and 2 that have a nitrogen content greater than 0.05 weight percent, and all fuel oil numbers 4, 5, and 6, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see § 60.17).

Response: In order to maintain consistency for boilers and process heaters that may be subject to various subparts under 40 CFR part 60, 61, 63, and 65, we have revised the definition of residual oil to be consistent with 40 CFR 60, Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units.

Commenter Name: Richard Krock
Commenter Affiliation: The Vinyl Institute
Document Control Number: EPA-HQ-OAR-2002-0058-3526-A1
Comment Excerpt Number: 21

Comment: EPA Should Clarify Fuel Definitions

The VI supports the development and implementation of separate emission limits for the multiple fuel categories. VI seeks clarification that the proposed definition of *distillate oil* is the same as the one in 40 CFR 60, Subpart Db. EPA also should ensure the definition of the term *residual oil* is identical to the definition in 40 CFR 60, Subpart Db in order to make these two rules impacting ICI boilers consistent with one another.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 176.

Commenter Name: Matthew Todd
Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)
Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2
Comment Excerpt Number: 144

Comment: The requirements in proposed §63.7550 are very unclear because of use of the term "affected source" to mean different things and all instances should be replaced with use of clear and specific defined terms.

Inconsistent use of the term "affected source" is a serious problem throughout this proposal. It is a particular problem in §63.7550, because the term appears to have been used in this section to refer to 1) individual boilers and process heaters (e.g., ones where there has been a deviation), 2) collections of boilers and process heaters (e.g., ones subject to emission limits), and 3) entire facilities (e.g., ones with Title V operating permits). Understanding is further blurred because new and reconstructed affect sources are defined in the proposal as individual boilers and process heaters, while existing affected sources are the collection of all boilers and process heaters at a facility in a particular subcategory that are not new or reconstructed. There are several places in §63.7550 where it is unclear whether reports are required for only specific boilers and process heaters meeting the indicated criterion or whether reports are required for all boilers and process heaters at the facility if any meets the indicated criterion. Every use of the term affected source should be replaced with either "individual boiler or process heater," "collection of boilers and process heaters," or "facility" as appropriate.

Response: The EPA acknowledges the commenter's concern and has clarified the requirements of §63.7550 to specify when the requirements apply to individual boilers and process heaters, collections of boilers and process heaters, or entire facilities.

Commenter Name: Matthew Todd
Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 143

Comment: The requirements in proposed §63.7550 are very unclear because of use of the term "affected source" to mean different things and all instances should be replaced with use of clear and specific defined terms.

As discussed in general in Section I of these comments, inconsistent use of the term "affected source" is a serious problem throughout this proposal. It is a particular problem in §63.7550, because the term appears to have been used in this section to refer to 1) individual boilers and process heaters (e.g., ones where there has been a deviation), 2) collections of boilers and process heaters (e.g., ones subject to emission limits), and 3) entire facilities (e.g., ones with Title V operating permits). Understanding is further blurred because new and reconstructed affect sources are defined in the proposal as individual boilers and process heaters, while existing affected sources are the collection of all boilers and process heaters at a facility in a particular subcategory that are not new or reconstructed. There are several places in §63.7550 where it is unclear whether reports are required for only specific boilers and process heaters meeting the indicated criterion or whether reports are required for all boilers and process heaters at the facility if any meets the indicated criterion. Every use of the term affected source should be replaced with either "individual boiler or process heater," "collection of boilers and process heaters," or "facility" as appropriate.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 144.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 167

Comment: The definition of "benchmarking" is inconsistent with the use of the term "benchmark" in the emission averaging portion of the rule. "Benchmark" should be the defined term, not "benchmarking", since "benchmarking" is not used anywhere in the rule and "benchmark" should be defined consistent with its use in the rule. We suggest the following.

Benchmark means the fuel use for a boiler or process heater for the one-year period before the date that an energy demand reduction occurs, unless it can be demonstrated that a different time period is more representative of historical operations.

Response: The EPA agrees with the commenter. The terminology and definition for "benchmark" have been updated accordingly.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 168

Comment: Proposed paragraph (i) of the "deviation" definition seems to make it a deviation to fail to meet a requirement that does not apply to a particular boiler or process heater. The wording of paragraph (i) needs to be revised to limit deviations to "any **applicable** requirement or obligation" rather than to "any requirement or obligation."

Response: The EPA agrees with the commenter's clarification. The definition of deviation has been updated accordingly.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 169

Comment: The last two sentences of the proposed definition of "electric utility steam generating unit" do not appear in that definition in the final electric utility NESHAP. Thus, some boilers and process heaters could end up being regulated under both rules or neither rule. The definition of "electric utility steam generating unit" in this rule should be made identical with the definition in the electric utility NESHAP.

Response: The definition of "Electric utility steam generating unit in the Boiler MACT is basically identical to MATS in that it combines the definitions of "Electric utility steam generating unit" and "Fossil fuel fired" that are in MATS.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 170

Comment: The definition of "federally enforceable" should indicate that federally enforceable limits and conditions are not limited to those listed in the definition as the current wording indicates. Additionally, since part 60 and 61 are cited as examples, parts 63 and 65 should also be cited.

Response: The EPA agrees with the commenter and has updated the definition of federally enforceable accordingly.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 171

Comment: The definition of load fraction is confusing and unclear and should be revised to the description used in Table 7. Specifically, the definition of "load fraction" should be changed to the following.

Load fraction means the actual heat input of a boiler or process heater divided by heat input during the performance test that established the minimum sorbent injection rate, expressed as a fraction (e.g. for 50 percent load the load fraction is 0.5).

Response: The EPA acknowledges the commenter's concerns and has revised the definition of load fraction to be consistent with Table 7 as follows, "Load fraction means the actual heat input of a boiler or process heater divided by heat input during the performance test that established the minimum sorbent injection rate or minimum activated carbon injection rate, expressed as a fraction (e.g. for 50 percent load the load fraction is 0.5)."

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 172

Comment: The definitions of "minimum activated carbon injection" and "minimum sorbent injection rate" use the term "load fraction" incorrectly and the parenthetical "percent" should be deleted from each definition.

Response: The EPA agrees with the commenters and has revised the definitions of minimum activated carbon injection rate and minimum sorbent injection rate accordingly.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 174

Comment: In the definition of "oxygen analyzer system" "boiler" should be "boiler or process heater" or "combustion device".

Response: The EPA agrees with the commenter and has updated the definition of oxygen analyzer system to add process heaters as follows, "Oxygen analyzer system means all equipment required to determine the oxygen content of a gas stream and used to monitor oxygen in the boiler or process heater flue gas or firebox. This definition includes oxygen trim systems. The source owner or operator must install, calibrate, maintain, and operate the oxygen analyzer system in accordance with the manufacturer's recommendations."

Commenter Name: Charles Johnson

Commenter Affiliation: The Aluminum Association

Document Control Number: EPA-HQ-OAR-2002-0058-3509-A1

Comment Excerpt Number: 1

Comment: The Aluminum Association has concerns that the current definition for *Metal Process Furnace* may lead to incorrect interpretations with regard to direct-fired equipment. The current definition of a process heater is:

"*Process heater* means an enclosed device using controlled flame, that is not a boiler, and the unit's primary purpose is to transfer heat indirectly to a process material ..."[i.e., indirect-fired units].

Only sources meeting the definition of "Process Heaters" are supposed to be affected sources under the Boiler MACT. The current definition of *Metal Process Furnace* is:

"*Metal process furnaces* include natural gas-fired annealing furnaces, preheat furnaces, reheat furnaces, aging furnaces, heat treat furnaces, and homogenizing furnaces."

To clarify that only indirect-fired furnaces are included within this definition, the Aluminum Association requests EPA to revise the definition to say:

"*Metal process furnaces* are a subcategory of *Process Heaters* which include natural gas-fired annealing furnaces, preheat furnaces, reheat furnaces, aging furnaces, heat treat furnaces, and homogenizing furnaces."

Response: The EPA acknowledges the commenter's concerns and has revised the definition of Metal process furnances as follows, "Metal process furnaces are a subcategory of Process heaters, as defined in this subpart, which include natural gas-fired annealing furnaces, preheat furnaces, reheat furnaces, aging furnaces, heat treat furnaces, and homogenizing furnaces."

Commenter Name: Shannon S. Broome

Commenter Affiliation: Auto Industry Forum (AIF)

Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1

Comment Excerpt Number: 50

Comment: E. The Proposed Revisions to the Definition of "Process Heater": Including Units Heating Hot Water as a Process Heat Transfer Medium Creates Unnecessary Confusion.

In the table of proposed technical corrections in the Boiler MACT Reconsideration Proposal, EPA indicates that it proposes to "[r]evise the definition of 'process heater' to include 'units heating hot water as a process heat transfer medium.'" *Id.* at 80,620. The following underlined portion reflects the proposed additions to the definition:

Process heater means an enclosed device using controlled flame, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material for use in a process unit, instead of generating steam. Process heaters include units heating hot water as a process heat transfer medium. Process heaters are devices in which the combustion gases do not come into direct contact with process materials. A device combusting solid waste, as defined in §241.3, is not a process heater unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Process heaters do not include units used for comfort heat or space heat, food preparation for on-site consumption, or autoclaves. Waste heat process heaters that use only natural gas, refinery gas, or other gas 1 fuels for supplemental fuel are excluded from this definition.

Id. at 80,653 (underline added). The absence of a rational basis or explanation of any kind as to the proposed revision is troubling in light of the substantive changes to the definition of "process

heater” that EPA seeks to effectuate. The proposed revision is likely to lead to confusion for affected sources, including those owned and/or operated by AIF members.

In bringing “units heating hot water as a process heat transfer medium” into the definition of “process heater,” EPA’s proposal creates the confusing circumstance whereby the regulations could classify a hot water heater as both a boiler *and* a process heater. Traditional, centralized boilers, for example, serve to heat facility buildings both for comfort *and* for some processes. Even though the majority of the annual heat load is related to comfort heat and *not* process heat, and the definition of “process heater” otherwise endeavors to exclude from its ambit those “units used for comfort heat,” the proposed, revised regulations would identify those units as both a boiler *and* a process heater. The confusion – and additional regulation – that would flow from EPA’s proposed revision is unnecessary and lacks any rational basis. It would be simpler to keep all hot water heaters classified first as boilers, regardless of whether they heat a process, *see, e.g., id.* at 80,650 (“Boiler means an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water”), and then exclude from regulation under the Boiler MACT those units that meet § 63.7575’s definition of “hot water heater,” *see, e.g., id.* at 80,641 (including a hot water heater as defined at § 63.7575 as one of the types of boilers and process heaters that is not subject to the Boiler MACT). EPA should rescind this proposed revision.

Response: We agree that the addition would cause confusion. In terms of the regulation, the unit would be subject to the same requirements regardless of whether it is classified as a boiler or process heater.

10B. Rule Language: Definitions (New)

Commenter Name: David A. Buff, Golder Associates Inc.

Commenter Affiliation: Florida Sugar Industry (FSI)

Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1

Comment Excerpt Number: 61

Comment: EPA has set forth a definition of 30-day rolling average as "the arithmetic mean of all valid data from 30 successive operating days that is calculated for each operating day using the data from that operating day and the previous 29 operating days." EPA has not defined "10-day rolling average" in the Proposed Boiler MACT Rule, although the CO CEMS-based emission limit is based on a 10-day rolling average. However, in Table 8, Item 10, Carbon Monoxide Emissions, the Proposed Boiler MACT Rule states "Correcting the data to 3 percent oxygen, and reducing the data to one-hour and daily block averages...", and "Reducing the data from the daily averages to 10- day rolling averages...". Thus, a 10-day rolling average would be comprised of ten (10) daily averages that are averaged together. The problem with this accounting method is that each day will count as 1/10th of the total 10-day average, even if a boiler only operates briefly on one of the days. For example, the 10 day average could be skewed upward, in an inappropriate and disproportionate manner, if the boiler has elevated emissions on a day in which the boiler only operates for one hour. To eliminate this problem, the EPA should define 10-day rolling average (or any rolling average) in the same manner as the 30-day rolling average (i.e., the arithmetic average of all valid data occurring over the 10-day period). With this

approach, an operating day with very little operating data would not have a disproportionate affect on the rolling average.

Response: The EPA agrees with the commenter and has revised the definitions of 10-day rolling average and 30-day rolling average accordingly. The definition of 10-day rolling average has been clarified as follows:

10-day rolling average means the arithmetic mean of the previous 240 hours of valid operating data. Valid data excludes hours during startup and shutdown, data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities, and periods when this unit is not operating. The 240 hours should be consecutive, but not necessarily continuous if operations were intermittent.

The definition of 30-day rolling average has been clarified as follows:

30-day rolling average means the arithmetic mean of the previous 720 hours of valid operating data. Valid data excludes hours during startup and shutdown, data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities, and periods when this unit is not operating. The 720 hours should be consecutive, but not necessarily continuous if operations were intermittent.

10C. Rule Language: Tables 1 through 10

Commenter Name: Russell A. Wozniak

Commenter Affiliation: The Dow Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3449-A1

Comment Excerpt Number: 29

Comment: Item #4.f. of Table 3 lists the requirements for a one-time energy assessment. This element requires the assessment include:

(f) A list of major energy conservation measures.

There is no definition for what constitutes a *major* energy conservation measure. However, the proposed rule provides the following definition

Cost-effective energy conservation measure means a measure that is implemented to improve the energy efficiency of the boiler or facility that has a payback (return of investment) period of 2 years or less. The preamble twice refers to "cost-effective energy conservation measures" with respect to the energy assessment (pp. 80602 and 80603 of the Federal Register). It appears the intent of EPA is that the energy-assessment list *cost-effective* energy conservation measures rather than *major* energy conservation measures. Therefore, we recommend that Table 3, item 4, element (f) be reworded as:

(f) A list of ~~major~~ cost-effective energy conservation measures.

Response: The EPA acknowledges the commenter's concern. It was the EPA's intent in the development of the proposed rule to require a list of cost-effective energy conservation measures as part of the one-time energy assessment, for which a definition was provided. Table 3 of the final rule has been revised accordingly for consistency.

Commenter Name: Jennifer Youngblood

Commenter Affiliation: National Tribal Air Association

Document Control Number: EPA-HQ-OAR-2002-0058-3667-A2

Comment Excerpt Number: 13

Comment: Some small BPH are standard units that are purchased as a complete unit and come with manufacturer's recommendations. However, many boilers and most process heaters are custom designs and usually are not single units provided by one manufacturer. Typically, burners come from one manufacturer, the tubes from another, and controls, the structure, and the firebox are field fabricated from components purchased from many sources. In these cases, there are no manufacturer's recommendations that deal with the entire unit. Thus, the burner manufacturer's recommendations do not deal with the needs to assure the integrity of the firebox or the refractory or consider instrumentation setup or response times. The owner/operator considers the manufacturer's recommendations, but must be free to adjust for the overall construction and condition of the unit and to fill in gaps where no manufacturer's recommendation exists or where the manufacturer did not consider other unit equipment needs or situations. Furthermore, as a unit ages, startup and shutdown needs can change and original manufacturer's recommendation may no longer be applicable. For instance, changing burners to low-NOx configurations, installing a different refractory, or changing firebox operating temperature, can require alteration to original manufacturer's recommendations or the original operating plan developed by the operator for a particular boiler or process heater. Finally, at very low firing in multi-burner process heaters, oxygen control is lost since only a few burners are operating and procedures have to deal with that situation. Thus, the phrase "as specified by the boiler manufacturer" should be deleted from the first sentence of Item 5 in Table 3.

Response: The final rule has been revised to delete the phrase "as specified by the boiler manufacturer" from the first sentence of Item 5 in Table 3. We agree with the commenter that there will be many instances where the original boiler manufacturer's specifications will not be available or where optimizing to them would not be appropriate.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 160

Comment: Table 1, Item 5.a. specifies that a span value of 600 ppmv is to be used for Method 10. This appears to be an error since the CO limit for that subcategory is 590 ppmv. For comparison, other Table 1 and 2 CO M10 span requirements are in the range of 2 times the emission limit. Therefore, it is recommended to change the required span for Table 1, Item 5.a to be 1000 ppm.

Response: The final span values have been deleted from Table 1 because 63.7525(a)(6) specifies that the span value of a CO CEMS must be two times the applicable emission limit.

Commenter Name: Michael D. Wendorf

Commenter Affiliation: FMC Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3453-A1

Comment Excerpt Number: 6

Comment: *COCEMS-Based Alternative Emission Limits and Monitoring*

Table 2 in the summary lists the alternate CO CEMS limit for the 'Coal-Burning Pulverized Coal' subcategory as 35 ppm @ 3% oxygen; this is in conflict with Table 2 in the rule itself which indicates 28 ppm @ 3% oxygen. FMC requests EPA to correct this discrepancy.

Response: The final CO CEMS limit in the rule and preamble summary tables have been updated to reflect the revised CO CEMS analysis, as discussed in the preamble and in Chapter 4 of the RTC document.

Commenter Name: David A. Buff, Golder Associates Inc.

Commenter Affiliation: Florida Sugar Industry (FSI)

Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1

Comment Excerpt Number: 13

Comment: It appears that Table 4 and Table 8 of the Proposed Boiler MACT Rule establish inconsistent requirements. In Table 4 ("Operating Limits For Boilers and Process Heaters"), item 9, indicates that the oxygen level must be maintained at all times so that it never drops "below the lowest hourly average oxygen concentration measured during the most recent CO performance test." 76 F.R. 80665, However, in Table 8 ("Demonstrating Continuous Compliance"), item 9 indicates that the "30-day rolling average oxygen content [must be maintained] at or above the lowest hourly average oxygen level measured during the most recent carbon monoxide performance test." 76 F.R. 80670. The FSI believes EPA should revise Table 4 to make it consistent with Table 8, because "EPA has determined that a 30- day rolling average for parameter monitoring and demonstration of continuous compliance with operating limits is appropriate for this rule." 76 F.R. 80610.

Response: The EPA thanks the commenter for their input. As noted by the commenter, it was the EPA's intent in the proposed rule to require the 30-day rolling average of the oxygen content for parameter monitoring and demonstration of continuous compliance, as discussed in Section V.D.6 of the proposal preamble and Table 8 of the proposed rule. Therefore, item 9 of Table 4 has been updated as follows, "For boilers and process heaters subject to a carbon monoxide emission limit that demonstrate compliance with an O₂ analyzer system as specified in §63.7525(a), maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen concentration measured during the most recent CO performance test."

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 158

Comment: The preamble also indicates that ESP parameter monitoring is based on a 12-hour block average (*see* 76 Fed. Reg. 80603), which conflicts with Table 4 of the rule.

Response: The rolling average in the proposal was the intent of EPA and the final rule includes a 30-day rolling average for ESP parameter monitoring.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 177

Comment: Table 4 contains requirements for operating limits, but it is unclear that these operating limits only apply if you are complying with a Table 1 or 2 numerical emission limit and, then only, while that limit is applicable (e.g., not during periods of startup and shutdown). The Table 4 first column header should be revised to make this clear. We recommend the Table 4 first column header be revised to "When complying with a Table 1 or 2 numerical limit, using".

Response: The EPA agrees with this clarification and has revised Table 4 accordingly.

Commenter Name: Richard D. Garber

Commenter Affiliation: Boise Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3686-A2

Comment Excerpt Number: 21

Comment: EPA should amend 02-trim monitoring and reporting requirements for units that will demonstrate compliance using an annual stack test.

40 CFR 63.7525(a) states that boilers subject to a carbon monoxide emissions limit must install either an oxygen analyzer or CO CEMS. For boilers that select use of the oxygen analyzer, 40 CFR 63.7525(a)(2) requires that the operator use the analyzer as part of an oxygen trim system and that the oxygen level be set at the minimum percent oxygen by volume established as the operating limit for oxygen according to Table 4 in the subpart. In Table 4, item 9, (FR page 80665) EPA states that the system "*maintain* the oxygen level such that it is not below the lowest hourly average oxygen concentration measured during the most recent CO performance test." In this section, EPA has failed to acknowledge the 30-day averaging time specified in Table 8, item 9 (FR page 80670).

Response: See the response to comment EPA-HQ-OAR-2002-0058-3504-A1, excerpt 13.

Commenter Name: Richard D. Garber

Commenter Affiliation: Boise Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3686-A2

Comment Excerpt Number: 22

Comment: The language in Table 4 and Table 9 should be consistent- each with the other and accurately reference the 30-day averaging period specified in Table 9. This is necessary so that Table 4 cannot be incorrectly interpreted or be suggested to require that the 02 level be used as some sort of hourly *limit* for the boiler. Should EPA continue to use the 30-day average for oxygen monitoring, Boise requests that EPA clarify that the calculation of the 30-day average be based on the most recent 720 hours of valid operating data to allow for the appropriate exclusion of outage data from the average.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3504-A1, excerpt 13.

Commenter Name: Traylor Champion

Commenter Affiliation: Georgia-Pacific LLC (GP)

Document Control Number: EPA-HQ-OAR-2002-0058-3465-A1

Comment Excerpt Number: 28

Comment: The proposed rule at §63.7520 and in Table 5 requires the use of the F-Factor methodology and equations as contained in EPA Method 19 for the calculation of particulate matter, hydrogen chloride, mercury, and total selected metals emissions on a pound per million BTU basis. The original technical documents for this method as contained in EPA-450/2-78-042a, Stack Sampling Technical Information, A Collection of Monographs and Papers, Volume I, however, make it clear that this method is envisioned as an alternative to the use of measured volumetric flows and heat inputs. Many sources subject to the proposed rule already measure and keep records of fuel heat inputs as part of their normal operations, therefore, to mandate the use of calculated data from secondary measurements as opposed to direct data from primary measurements would seem to increase the potential for error in the resulting emissions values. For multi-fuel sources, Method 19 itself requires that the fraction of heat input from each type of fuel be determined in order to prorate the applicable F-Factors. Since direct measurement of heat input for all fuels for a given multi-fuel boiler is often not possible, proration of the applicable F-Factors will necessarily require a combination of direct measurement and back-calculation using steam flow and boiler efficiency data. Once data adequate to calculate an appropriate prorated F-Factor is available, requiring its further use to calculate total heat input via F-Factor methodology would seem redundant. The use of approaches other than Method 19 could be accomplished via a request to EPA for approval of alternative monitoring, however, amendment of the proposed rule to explicitly allow for the use of a broader range of options would be a far more efficient resolution.

GP urges EPA to: Amend §63.7520 and Table 5 to provide for the use of Method 19 or some other technically appropriate method(s) for determining heat input data.

Response: We disagree with the commenter that 63.7520 and Table 5 should be amended to allow other undefined method and the commenter does not provide information on how to determine if another methods is technically appropriate.

Commenter Name: Michael D. Wendorf
Commenter Affiliation: FMC Corporation
Document Control Number: EPA-HQ-OAR-2002-0058-3453-A1
Comment Excerpt Number: 13

Comment: Table 5 of the proposed rule does not describe the stack test method requirements for boilers which elect to use the alternative TSM limit. FMC requests EPA to include the appropriate stack test method in Table 5.

Response: The EPA acknowledges the commenter's concerns. As discussed in Section III.F of the proposed rule, we intended to require initial and annual stack tests using EPA Method 29 at 40 CFR part 60, appendix A-8 to determine compliance with the alternate TSM emission limits. Table 5 of the final rule has been updated to include EPA Method 29 and other applicable stack test requirements for boilers electing to use the alternative TSM emission limits.

Commenter Name: Matthew Todd
Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)
Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2
Comment Excerpt Number: 178

Comment: For clarity, we recommend that Item 1 in Table 5 be labeled "Filterable particulate matter" rather than "Particulate Matter".

Response: The EPA agrees with the commenter and has revised Table 5 accordingly.

Commenter Name: Robert Ellerhorst
Commenter Affiliation: Michigan State University
Document Control Number: EPA-HQ-OAR-2002-0058-3674-A2
Comment Excerpt Number: 11

Comment: As found in Table 7 of the proposed rule, boilers and process heaters who use sorbent injection are required to develop a site-specific minimum sorbent injection rate based on HCI performance testing. MSU is requesting U.S. EPA to provide clarification as to what is meant by sorbent injection.

In the electrical generation industry, limestone is commonly referred to as sorbent. As discussed previously, MSU operates a CFB boiler who's bed is composed of limestone, coal, and ash. During startup, the limestone is incorporated into the combustion chamber with the other components to build the bed and begin heat transfer. Limestone continues to be incorporated on an as-needed basis during operation, but not at a rate that could be considered linear.

As such, MSU would like to clarify what U.S. EPA intends for this requirement to be applicable to sorbent injections systems that are used as a control device, such as a dry scrubber, and did not mean to include the incorporation of limestone into a CFB bed.

Response: It was the EPA's intent in the proposed rule to require facilities using dry scrubbers as an add-on control device to establish a site-specific minimum sorbent injection rate and conduct monitoring of the sorbent injection rate to demonstrate compliance. The definition of Dry scrubber in the proposed rule included "an add-on air pollution control system that injects dry alkaline sorbent (dry injection) or sprays an alkaline sorbent (spray dryer) to react with and neutralize acid gas in the exhaust stream forming a dry powder material". Sorbent injection systems in fluidized bed boilers and process heaters were included in this definition. For clarification, the EPA has revised the definition of "Minimum sorbent injection rate" to clarify that not only add-on sorbent injection systems used as pollution control systems are included in this definition. The definition of "Minimum sorbent injection rate" has been revised as follows: Minimum sorbent injection rate means:

The load fraction multiplied by the lowest hourly average sorbent injection rate for each sorbent measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits; or

For fluidized bed combustion, the lowest average ratio of sorbent to sulfur measured during the most recent performance test.

Commenter Name: Steve Gossett

Commenter Affiliation: Eastman Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3669-A2

Comment Excerpt Number: 27

Comment: We note that Table 8, item 11 does not state that a 30-day rolling average is used for boiler or process heater operating load. EPA needs to clarify this requirement in the final rule.

Response: The maximum operating load is an absolute value that should not be exceeded and it is not appropriate for this value to be changed to a 30-day rolling average. In EPA's stack test policy (L. Lund EPA/OECA Issuance of the Clean Air Act National Stack Testing Guidance April 27, 2009; Available on-line at: <http://www.epa.gov/compliance/resources/policies/monitoring/caa/stacktesting.pdf>), the EPA recommends that performance tests be performed under those representative (normal) conditions that:

- represent the range of combined process and control measure conditions under which the facility expects to operate (regardless of the frequency of the conditions); and
- are likely to most challenge the emissions control measures of the facility with regard to meeting the applicable emission standards, but without creating an unsafe condition.
- If operating at maximum capacity would result in the highest levels of emissions, operating at this level would not create an unsafe condition, and the facility expects to operate at that level at least some of the time, EPA recommends that the facility should conduct a stack test at maximum capacity or the allowable/permitted capacity.
- An affected source should conduct its performance test at an operating load that the source is not expected to exceed (with the exception of a 10% allowance). The EPA has provided a cushion of 10 percent to provide for some flexibility in operating loads. Operating load is a

different type of parameter than the other operating parameters which are based on 30-day rolling averages; these parameters are designed to give information on how well the source is being controlled, while the operating load gives information on if the compliance test was performed under representative emissions loading conditions.

- Item 11 of Table 8 and item 8 of Table 4, however, have been revised to clarify that the maximum operating limit is 110% of the highest hourly average operating load recorded during the performance test in order to be consistent with the other operating limit which are based on hourly averages.

Commenter Name: Felix Mestey, on behalf of Donald R. Schregardus

Commenter Affiliation: Clean Air Act Services Steering Committee, Department of Defense (DoD)

Document Control Number: EPA-HQ-OAR-2002-0058-3427

Comment Excerpt Number: 13

Comment: DoD supports EPA's clarification that compliance extensions can be requested under §63.6(i) of the General Provision when additional time is needed to install control devices, combined heat and power, or waste heat recovery to comply with the rule. However, the statement added to Table 10 to Subpart DDDDD should be clarified to ensure it is clear that the statement is understood to expand and not limit the provisions of §63.6(i).

Recommendation

Clarify the sentence added to the comment corresponding to §63.6(i) in the third column of Table 10 to subpart DDDDD as follows:

*Yes. **Note:** Facilities may also request extensions of compliance for the installation of combined heat and power or waste heat recovery as a means of complying with this subpart."*

Response: EPA agrees with the commenter that the provisions of 40 CFR 63.6(i) are not intended to be limited. We have modified Table 10 accordingly.

10D. Rule Language Excluding Definitions and Tables 1 through 10

Commenter Name: Lee Zeugin and Lauren Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1

Comment Excerpt Number: 43

Comment: EPA proposes to remove the reporting provision specific to PM CEMS and to replace the more general reporting provision with three separate provisions. The first provision would require reporting of the "results of performance tests" within 60 days. Proposed § 63.7550(h). The second provision would require reporting of "relative accuracy test audit data" within 60 days of each CO and Hg CEMS "performance evaluation test." Proposed § 63.7550(i). The third provision would require quarterly reporting of "all the calculated 30 day rolling average values based on the daily CEMS (CO and Hg) and CPMS (PM CPMS output, scrubber pH, scrubber liquid flow rate, scrubber pressure drop) data." Proposed § 63.7550(j).

Proposed §§ 63.7550(h) would require reporting to WebFIRE using ERT and something called the “Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through [CDX].” Proposed §§ 63.7550(i) would require reporting to CDX using only ERT. Proposed §§ 63.7550(j) would require reporting to WebFIRE using only CEDRI. In support of its proposal, EPA again offers general assertions of reduced burden and emission factor improvements. With respect to the substantive content of the reports, EPA states that “[a]nother advantage is that ERT clearly states what testing information would be required.” 76 Fed. Reg. at 80,605. EPA did not respond to any of UARG’s prior comments related to the burden of this electronic reporting and the proposed benefits for the development of emission factors.

Response: We agree with comment from the 2009 ANPR that the template is not yet available and the process for transmitting the quarterly reports of the type required by this rule are not yet available for review at the time of the proposal. In response to this comment, we have changed the rule to reduce the reporting from quarterly to semi-annually and clarify that implementation of the requirement to electronic submit semi-annual reports will commence only when the electronic reporting tools (e.g., data submittal templates) and the data submission process are operative. Because the reporting template and data submission process for stack test reports are completed and operational, the requirement to submit stack test reports electronically will be effective on the compliance date. We also agree with the 2009 ANPR comment that EPA should limit its requirement for a reporting template to a specific format so as to allow facilities to procure or develop their own software to comply with that format and the associated reporting elements. The EPA plans to revise the electronic reporting requirements to provide an XML schema to allow facilities to obtain their own software that meets the XML schema specifications.

The EPA disagrees with the commenter’s 2009 ANPR comment that the ERT, as currently designed, requires the reporting of vast amounts of information that are not otherwise required to be reported under the applicable EPA test methods or EPA’s proposed rule. The commenter also adds that “the EPA must comply with the Paperwork Reduction Act and specify each piece of information it seeks to have reported, explain how those data have practical utility, and estimate the costs of collection and EPA review of those data. EPA has done none of that.” The ERT does not require vast amounts of data that are not otherwise required to be reported by a rule or method. The ERT was designed using the performance test report reporting requirements in the parts 60 and 63 General Provisions and the Emissions Measurement Center’s Guidance Document (GD-43) entitled “Preparation and Review of Emission Test Reports”. See <http://www.epa.gov/ttn/emc/guidlnd/gd-043.pdf>. There are a few data fields that aren’t mentioned in the general provisions and the guidance document, but these are facility and unit identification designations, such as the Federal Reference Number, fields that State and Local Air Pollution Control Agencies may require, and/or data fields that are not mandatory for performance test report submission.

The EPA agrees with the comment by the commenters that the EPA has not explained how the requirements of the Cross-Media Electronic Reporting Rule (CROMERR) have been met. Working closely with the EPA’s Office of Environmental Information, the EPA’s Office of Air Quality Planning and Analysis has established an electronic reporting process that meets the CROMERR requirements. The EPA has established a portal for electronic submission of the ERT data through the Central Data Exchange (CDX), where all electronic data submitted to EPA must be submitted. All users who want to submit ERT data must register for use of the CDX

which meets the signatory requirements of CROMERR. The EPA has developed the Compliance and Emissions Data Reporting Interface (CEDRI) that provides the user with the mechanism to submit ERT data through the CDX to the EPA's data repository, WebFIRE. Together, this system meets the CROMERR requirements and the requirements mentioned by UARG in 40 CFR section 3.2000(b)(5). The EPA agrees with the commenters assertion that the EPA has not explained how the information required to be submitted under the ERT to WebFIRE will be used to develop emissions factors. The EPA has a draft version of the Emissions Factors Development Procedures on the AP-42 website (see <http://www.epa.gov/ttn/chief/ap42/>) now. Although the EPA will not change the basic procedure of using the average of available and appropriate performance test data to develop emissions factors, the final specific procedures are not available in the procedures document have not been published.

Commenter Name: Jessica Bridges

Commenter Affiliation: United States Clean Heat & Power Association (USCHPA)

Document Control Number: EPA-HQ-OAR-2002-0058-3501-A1

Comment Excerpt Number: 22

Comment: 40 CFR 63.7533(b)(2), Amend this paragraph to clarify that the use of emission credits from implementation of energy conservation measures can only be used by existing units, and that these credits can be used to demonstrate initial and on-going compliance.

We are supportive of this use of emission credits obtained from energy conservation measures.

Response: The EPA thanks the commenter for their support. We are maintaining the applicability to emission crediting provisions (now referred to as 'efficiency credits' for both initial and continuous compliance.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 162

Comment: Proposed §63.7550(d) and (e) identify the required content of the periodic report where deviations are reported. Because of the use of the term affected source, it is unclear whether the subparagraphs require reporting of information only for the boiler or process heater where the deviation occurred, for all boilers and process heaters at the facility, or for all boilers and process heaters in the same subcategory as the boiler or process heater where the deviation occurred (i.e., the existing source affected source). It should be made clear that the information in the §63.7550(d) and (e) subparagraphs is only required for the boiler or process heater for which there was a deviation by replacing "affected source" throughout these sections with "boiler or process heater where the deviation occurred".

Response: The EPA has clarified 40 CFR 63.7550(d) and (e) in the final rule to specify that the requirements apply only to individual boilers and process heaters where a deviation has occurred.

Commenter Name: Cheryl Suttman
Commenter Affiliation: Ohio EPA, Division of Air Pollution Control
Document Control Number: EPA-HQ-OAR-2002-0058-3795-A1
Comment Excerpt Number: 1

Comment: Typo in 63.7550(c)(6): Equation 5 of 63.7530 should be Equation 7

Response: EPA thanks the commenter for the correction. 40 CFR 63.7550(c)(6), now 63.7550(c)(8), has been updated accordingly.

Commenter Name: Cheryl Suttman
Commenter Affiliation: Ohio EPA, Division of Air Pollution Control
Document Control Number: EPA-HQ-OAR-2002-0058-3795-A1
Comment Excerpt Number: 2

Comment: 40 CFR 63.7515(g) allows 90 days to report the results of a performance test or fuel analysis (following the test date). Should this be changed to 60 days?

40 CFR 63.7550(h) requires performance test results to be submitted to the WebFire database within 60 days following the performance test.

Response: We agree that 40 CFR 63.7515(g), now 63.7515(f), should be changed to 60 days. It is the EPA's intent that the timeframe for reporting the performance test results is 90 days. This timeframe is also consistent with the timeframe on the final Mercury and Air Toxics Standards (MATS). 40 CFR 63.7515(g) has been modified to reflect a 60 day timeframe, accordingly.

Commenter Name: Cheryl Suttman
Commenter Affiliation: Ohio EPA, Division of Air Pollution Control
Document Control Number: EPA-HQ-OAR-2002-0058-3795-A1
Comment Excerpt Number: 3

Comment: In 40 CFR 63.7522(a) existing boilers or process heaters can demonstrate compliance through emissions averaging if their averaged emissions are not more than 90% of the applicable emission limit, according to the procedures in 63.7522.

In 40 CFR 63.7522(d) the averaged emission rate from the existing boilers and process heaters participating in the averaging group must be in compliance with the limits in Table 2 at all times.

Should 40 CFR 63.7522(d) read: the averaged emission rate from the existing boilers or process heaters participating in the averaging group must not exceed 90% of the limits in Table 2?

Response: EPA thanks the commenter for the correction. 40 CFR 63.7522(d) has been updated accordingly.

Commenter Name: Cheryl Suttman
Commenter Affiliation: Ohio EPA, Division of Air Pollution Control

Document Control Number: EPA-HQ-OAR-2002-0058-3795-A1

Comment Excerpt Number: 4

Comment: Can boilers and process heaters burning the same fuel (only oils, solids are well defined) be averaged in the same averaging group? They would be considered “units” designed to burn the same fuel and would share the same limit, but a boiler and a process heater are designed so differently. It seems a little unusual that a heater and boiler would be able to average their emissions for compliance, especially if the boiler had controls and the heater did not; and/or one was used for heating and the other was used for a production process.

Response: Units within the same subcategory can be averaged whether they are all boilers, process heaters, or both.

Commenter Name: Monica Lopes

Commenter Affiliation: NAES Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3808-A1

Comment Excerpt Number: 4

Comment: Under the revised 40CFR63.7505(d)(1), EPA states that the requirement for a facility to develop and submit a site specific monitoring plan does not apply to affected sources with existing monitoring plans that apply to CEMS and COMS prepared under Appendix B to part 60 and that meet the requirements of 40CFR63.7525. However, Appendix B to Part 60 only provides the performance specifications to be used for the design, performance, and installation of a COMS/CEMS. Please clarify which Part 60 monitoring plans EPA is referring to in this section of the rule.

Response: The EPA agrees with the commenter and has revised the exception under 40 CFR 63.7505(d)(1) to read as follows: "This requirement to develop and submit a site specific monitoring plan does not apply to affected sources with existing CEMS or COMS operated according to the performance specifications under appendix B to part 60 of this chapter and that meet the requirements of §63.7525."

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 157

Comment: To avoid confusion, EPA should make sure that the final preamble language addresses and matches the final requirements in the rule. For example, in this Reconsideration Proposal, the preamble indicates that a new fuel analysis is required for each new fuel supplier (*see* 76 Fed. Reg. 80604). This requirement is unreasonable and is not included in the regulatory text.

Response: The EPA thanks the commenter for their input. In keeping with the proposed rule language, the final rule does not require a new fuel analysis for each new fuel supplier. This statement has been removed in the preamble for the final rule.

Commenter Name: David A. Buff, Golder Associates Inc.
Commenter Affiliation: Florida Sugar Industry (FSI)
Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1
Comment Excerpt Number: 58

Comment: In the Proposed Boiler MACT Rule, EPA states "Another important proposed benefit of submitting these data to the EPA at the time that the source test is conducted is that it should substantially reduce the effort involved in data collection activities in the future". 76 F.R. 80605. This statement should be clarified to provide that the performance test report should be submitted to EPA within 60 days of completion of the performance test. This clarification would make the text consistent with standard state requirements. It should also be clarified that only the information required in a performance test report must be submitted to the WebFIRE database.

Response: 63.7550(h) of the final rule reflects a 60 day timeframe for submittal of performance test results and in keeping with the requirements outlined in 40 CFR 63.7515(g). See the response to comment EPA-HQ-OAR-2002-0058-3795-A1, excerpt 2. As previously specified in 40 CFR 63.7550(h), only data collected using test methods on the ERT website are subject to the requirement to submit reports electronically to WebFIRE.

Commenter Name: Douglas A. McWilliams
Commenter Affiliation: American Municipal Power
Document Control Number: EPA-HQ-OAR-2002-0058-3685-A2
Comment Excerpt Number: 39

Comment: EPA Should Clarify that Emission limits, Operating limits, and Monitoring Requirements Apply Only During Periods of Source Operation

The language of the Proposed Rule states that emission limits, operating limits, and work practice standards apply "at all times" except for periods of startup and shutdown. We do not believe it was EPA's intent to imply that the source remains subject to these limits even when the emission unit is not operating and is not producing emissions. EPA acknowledged that it did not intend for CPMS and opacity limits to apply during periods of startup and shutdown, because the unit is not subject to a numeric emission limit during these times. It would be nonsensical (and impossible as a practical matter) to require sources to establish compliance with these standards while the source and its associated control equipment are down. EPA should simply clarify in the text of the final rule that the emission limits, work practice standards, and operating limits apply "at all times the affected unit is operating" rather than "at all times."

Response: The EPA agrees with the commenter and has revised the final rule accordingly.

Commenter Name: Matthew Todd
Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)
Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2
Comment Excerpt Number: 5

Comment: Many requirements require that something be "minimized" (e.g., minimize the effects of swirling flow or abnormal velocity distributions on flow measurements). This term is unclear and nebulous. Experience shows that over the years it will be interpreted differently by affected facilities and regulators. Some regulators and citizens will interpret "minimize" to mean "eliminate." In order to avoid technologically infeasible and cost ineffective interpretations, every use of the term "minimize" in this regulation, where it is not currently qualified, should be qualified by adding the phrase "to the extent practicable" or "consistent with good engineering practice."

Response: The EPA agrees with the commenter and has updated the final rule accordingly.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 6

Comment: The term "affected source" is used frequently throughout the proposal when the intent is clearly to mean each individual boiler and process heater. Since the existing affected source is a collection of boilers and process heaters and not each individual one (as the new and reconstructed affected source is defined), most uses of the term "affected source" in the proposal are incorrect and confusing. Wherever it is intended that a requirement apply to each individual boiler and process heater the term "affected source" should be replaced with the phrase "each boiler and process heater." Similarly, the term "affected source" is sometimes used to mean facility, even though that is not how it is defined in proposed §63.7490(a). Wherever it is intended that a requirement apply to the facility the term "affected source" should be replaced with the word "facility." See Comment II.10.C for a specific example.

Response: The EPA agrees with the commenter and has clarified the requirements of the final rule accordingly.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 7

Comment: In general, the proposed language (including the preamble discussion and the requirements in the Tables) is inconsistent in the terminology used when referring to particular subcategories. This is confusing, leads to misunderstanding, and could lead to misinterpretation. For instance, proposed §63.7540(a)(10) begins "If your boiler or process heater is either in the natural gas, refinery gas, other gas 1, or metal process furnace subcategories ..." However, there is no natural gas subcategory, no refinery gas subcategory and no other gas 1 subcategory. Those are three fuels that if burned in a boiler or process heater would qualify that boiler or process heater to be in the "unit designed to burn gas 1" subcategory, if the other criterion in the subcategory definition is met. If the other criterion is not met, the boiler or process heater would be in a different subcategory even if it primarily fired natural gas, refinery gas, and/or other gas

1. This same mistaken terminology is used throughout the rule to refer to the gas 1 subcategory. By not using the proper subcategory names §63.7540(a)(10) could be misinterpreted and at a minimum is confusing. We recommend all references to subcategories be changed to use the defined subcategory name or a consistent short name that is set out in the subcategory definition.

Response: The EPA agrees with the commenter's concerns and has revised the final rule accordingly.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 8

Comment: Liquid and solid fired BPH are each in two subcategories (for instance a liquid fired unit is in the liquids subcategory and either the light liquids or heavy liquids subcategory.) However, rule requirements are all written as if a unit can only be in one source category. A general clean-up of rule language to change "subcategory" to "subcategories" where appropriate would improve rule clarity.

Response: The EPA agrees with the commenter and has revised the final rule accordingly.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 36

Comment: The use of fuel type terminology is inconsistent throughout the rule and should be reviewed and corrected where necessary. Of particular concern, "residual oil" is used in many places where "heavy liquid" may have been intended.

Response: The EPA appreciates the commenter's input. The fuel type terminology has been updated in the final rule (see 40 CFR 63.7510(d), 40 CFR 63.7525(b), and the definition of "liquid fuel" in 40 CFR 63.7575) to reflect "heavy liquid" and "light liquid" for clarification and consistency.

Commenter Name: Stephen E. Woock

Commenter Affiliation: Weyerhaeuser Company

Document Control Number: EPA-HQ-OAR-2002-0058-3523-A1

Comment Excerpt Number: 6

Comment: EPA needs to ensure that the rule clearly establishes a bright line differentiating between the compliance measurement data that apply to either short-term stack test based limits or CO CEMS limits since the limits must be aligned with the type of data and averaging period used in formulating the limit.

Response: We agree with the commenter for the need for clarity in how a source is to comply with either the stack-based CO limit or with the CEM-based CO limit.

Commenter Name: Stephen E. Woock

Commenter Affiliation: Weyerhaeuser Company

Document Control Number: EPA-HQ-OAR-2002-0058-3523-A1

Comment Excerpt Number: 15

Comment: There are a multitude of requirements for performance testing, continuous emissions monitoring systems (CEMS), continuous parameters monitoring systems (CPMS), operating parameters, instrument calibration and other quality assurance requirements embedded in the 2011 final rule and with a number of changes proposed in the December 2011 re-proposal. EPA should streamline the requirements where possible, correct discrepancies identified in comments submitted by the trade groups and respond to opportunities to minimize the monitoring burdens these extensive and complex provisions carry with them.

Response: We have streamline the requirements, where appropriate, have corrected discrepancies, when identified, and made changes to minimize the testing and monitoring burden.

Commenter Name: John V. Corra, Director

Commenter Affiliation: State of Wyoming Department of Environmental Quality

Document Control Number: EPA-HQ-OAR-2002-0058-3435-A1

Comment Excerpt Number: 1

Comment: The State has concerns regarding the overlap of requirements in the rules with those in the general provisions, particularly recordkeeping and reporting. Complying with both the general provisions and the requirements in the rule causes confusion for both the State and industry. This confusion often results in small companies, with limited resources, having to hire a third party contractor to ensure compliance. Wyoming recommends that EPA add language that waives the recordkeeping and reporting general provisions when there are very specific, detailed requirements for recordkeeping and reporting within the rule, and has provided some examples below that illustrate areas of compliance confusion. These examples are not inclusive of all problem areas within the rule.

The general provisions for the notification of compliance status in § 63.9(g)(2)(ii) states: "The notification must be sent before the close of business on the 60th day following the completion of the relevant compliance demonstration activity specified in the relevant standard".

In regard to the boiler rules, it is unclear what qualifies as a "relevant compliance demonstration activity". It is also unclear whether or not the activities are to be reported through both the notification of compliance status and the compliance reports described in § 63.7550.

It is stated in § 63.7515(g) that performance tests shall be submitted within 90 days.

The State requests clarification on whether that submission should follow the general provision requirements for a "notification of compliance status" or whether it is considered a "report".

Also, § 63.7530(h) requires a statement that good combustion practices were used and oxygen concentrations were maintained for each startup and shutdown event, as part of the notification of compliance status.

Clarification is needed regarding whether or not this is a onetime report required under the initial notification of compliance status, or whether the report should be submitted on a regularly scheduled basis.

Response: The requirement in 63.7515 for reporting the results of the performance tests has been changed to 60 days to be consistent with the General Provisions. 63.7530(h) pertains to the requirements for demonstrating initial compliance. These same requirements are in 63.7550 for reporting on a regularly scheduled basis in order to demonstrate continuous compliance.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 15

Comment: The compliance timing for BPH that stop burning solid waste must be clarified and it should be clarified that only when it is intended to permanently cease burning solid waste does the CISWI unit become subject to the appropriate BPH NESHAP.

1. Proposed §§60.2145(a)(2) and (3), and 60.2710(a)(2) and (3) and the proposed definition of CISWI unit specify that a unit that has been subject to CISWI remains subject for 6 months after ceasing to combust solid waste. On the other hand, §63.7495(e) of this proposal states:

(e) If you own or operate an industrial, commercial, or institutional boiler or process heater and would be subject to this subpart except for the exemption in §63.7491(l) for commercial and industrial solid waste incineration units covered by part 60, subpart CCCC or subpart DDDD, and you cease combusting solid waste, you must be in compliance with this subpart on the effective date of the switch from waste to fuel.

"Effective date" is unclear in this context and should be clarified by specifically referencing the provisions of the CISWI rules that identify this effective date as being the date identified by the source for the transition from the CISWI rule to the BPH major source rule and not the date the source ceases to burn solid waste or the effective date of the BPH major source rule.

2. Proposed §63.7495(e) deals with compliance timing for BPH that have been subject to the CISWI rule, but stop firing solid waste and thus become subject to this major source rule instead. As currently worded, a temporary stoppage (which happens frequently at CISWI units) would appear to make the BPH rule applicable rather than CISWI. The language of §63.7495(e) needs to be clear that this transition only occurs if the unit is stopping solid waste burning permanently.

3. Proposed §63.7495(e) should also be clarified to confirm that the requirements of the CISWI rule no longer apply after the effective date of the transition.

4. To address these issues (1, 2 and 3) we suggest the following revision to §63.7495(e).

(e) If you own or operate an industrial, commercial, or institutional boiler or process heater and would be subject to this subpart except for the exemption in §63.7491(l) for commercial and industrial solid waste incineration units covered by part 60, subpart CCCC or subpart DDDD, and you permanently cease combusting solid waste, you must be in compliance with this subpart and are no longer subject to part 60, subparts CCCC or DDDD beginning on the effective date of the switch from waste to fuels identified under the provisions of §§60.2145(a)(2) and (3) or §§60.2710(a)(2) and (3).

Response: We agree with the commenter and have made the suggested revision to §63.7495(e). (e) If you own or operate an industrial, commercial, or institutional boiler or process heater and would be subject to this subpart except for the exemption in §63.7491(l) for commercial and industrial solid waste incineration units covered by part 60, subpart CCCC or subpart DDDD, and you cease combusting solid waste, you must be in compliance with this subpart and are no longer subject to part 60, subparts CCCC or DDDD beginning on the effective date of the switch as identified under the provisions of §§60.2145(a)(2) and (3) or §§60.2710(a)(2) and (3).

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 23

Comment: Since some process heaters produce steam as a waste heat recovery step, though not necessarily using a "waste heat boiler or process heater" we suggest proposed §63.7500(a)(1) be revised as follows:

...The output-based emission limits are not applicable to process heaters **that do not generate steam**.

Response: The EPA acknowledges the commenter's concern and recognizes that some process heaters may produce steam. 40 CFR 63.7500(a)(1) has been revised to specify that the output-based emission limits are applicable to process heaters that generate steam.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 103

Comment: Approval of alternative monitoring and work practices to those specified in Tables 3 and 4 should be delegated.

Proposed §63.7500(a)(2) provides:

(2) You must meet each operating limit in Table 4 to this subpart that applies to your boiler or process heater. If you use a control device or combination of control devices not covered in Table 4 to this subpart, or you wish to establish and monitor an alternative operating limit and

alternative monitoring parameters, you must apply to the EPA Administrator for approval of alternative monitoring under § 63.8(f).

Similarly, proposed §63.7500(b) provides:

(b) As provided in § 63.6(g), EPA may approve use of an alternative to the work practice standards in this section.

Use of §63.8(f) and (g) to obtain approval of monitoring or work practices that deviate from that specified in a regulation is generally unworkable if that authority is not delegated, because EPA has demonstrated its inability to respond to such requests in a timely manner. This always puts sources at risk, but particularly so in this case, since sources may be unable to comply if Table 4 is not applicable to their control configuration or needs to be adjusted to make it applicable. Because of the large number and wide variety of BPH operations, the need for alternate monitoring and revisions to the work practice requirements is likely to be much more common than in typical rules, thus amplifying the problem. We therefore strongly recommend that EPA delegate this authority.

Should EPA opt to retain this authority, to avoid violations due to EPA inaction, the Agency should add language to the final BPH NESHAP rule that provides that any §63.8(f) or (g) request on which EPA does not act within 90 days is considered approved.

Response: We disagree with the suggestion to delegate authority to a state regulatory authority for approval of alternative work practice standards. The work practice standards are developed under section 112(h) of the Clean Air Act instead of MACT emission limits but are considered MACT-based standards. It is EPA who is mandated to develop the MACT-based standards and, thus, the authority to approve any alternative MACT standards.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 115

Comment: In addition, §63.7510(a)(2)(iii) appears to require mercury fuel analysis for natural gas:

"You are not required to conduct a chlorine fuel analysis for any gaseous fuels. You must still conduct a fuel analysis for mercury on gaseous fuels unless the fuel is exempted in paragraphs (a)(2)(i) through (iii) of this section."

EPA should clarify this paragraph to indicate that mercury analysis is also not required for natural gas or refinery gas.

Response: The EPA disagrees and believes that the intent of the rule is clear. 40 CFR 63.7510(a) applies to boilers or process heaters that "demonstrate compliance with any of the applicable emission limits in Tables 1 or 2 of this subpart". Emission limits are not provided for the units designed to burn gas 1 subcategory in these tables, therefore, the requirements of 40 CFR 7510(a) do not apply to the units burning natural gas, refinery gas, or other gas 1 fuels.

Furthermore, 40 CFR 7510(a)(2)(ii) specifically exempts natural gas, refinery gas, and other gas 1 fuels co-fired with fuels in other subcategories, affirming the EPA's intent that fuel analyses are not required for fuels from the gas 1 category.

40 CFR 63.7510(a)(2) also requires that the fuel analysis be conducted according to the requirements of 40 CFR 63.7521 and Table 6. The EPA's intent is clear in 40 CFR 63.7521(a), which states, "For gas 2 (other) fuels, you must conduct fuel analyses for mercury according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable....You are required to conduct fuel analyses only for fuels and units that are subject to emission limits for mercury, hydrogen chloride, or total selected metals in Tables 1 and 2 to this subpart."

The EPA believes that 40 CFR 7510(a)(2)(iii) is clear in that it specifically applies to gaseous fuels that are subject to the emission limits in Tables 1 and 2 of the final rule, and not to units in the gas 1 category. Therefore, no changes have been made to the final rule.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 60

Comment: §63.7510(a)(2)(iii) appears to require mercury fuel analysis for natural gas:

§63.7510(a)(2)(iii) You are not required to conduct a chlorine fuel analysis for any gaseous fuels. You must still conduct a fuel analysis for mercury on gaseous fuels unless the fuel is exempted in paragraphs (a)(2)(i) through (iii) of this section.

EPA needs to clarify this paragraph to indicate that mercury analysis is also not required for natural gas or refinery gas.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 115.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 125

Comment: Proposed §63.7510(a)(2)(iii) specifies in the second sentence that "You must still conduct a fuel analysis for mercury on gaseous fuels unless the fuel is exempted in paragraphs (a)(2)(i) through (iii) of this section" but the reference should only be to (a)(2)(i) and (ii), since (iii) exempts fuels from the chloride analysis requirement, not the mercury analysis requirement.

Response: The EPA thanks the commenter for the correction and has revised 40 CFR 63.7510(a)(2)(iii) to correct the reference.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 114

Comment: We agree with EPA's determination that no fuel analysis for chloride is required for gases and that operators are not required to conduct the mercury fuel specification analyses for gaseous fuels that are natural gas, refinery gas, or otherwise subject to another subpart of part 63. EPA also should exempt those sources using process gases that otherwise are regulated under Parts 60 and 61 from conducting a fuel specification analysis. Specifically, §63.7510(a)(2)(ii) and §63.7521(f)(2) should be amended with the addition of the bold language noted to read:

*§63.7510(a)(2)(ii) When natural gas, refinery gas, other gas 1 fuels are co-fired with other fuels, you are not required to conduct a fuel analysis of those fuels according to § 63.7521 and Table 6 to this subpart. If gaseous fuels other than natural gas, refinery gas, or other gas 1 fuels are cofired with other fuels and those gaseous fuels are subject to another subpart of this part, **part 60, or part 61**, you are not required to conduct a fuel analysis of those fuels according to § 63.7521 and Table 6 to this subpart.*

*§63.7521(f)(2) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for gaseous fuels for units that are subject to another subpart of this part, **part 60, or part 61**.*

EPA has already extended the exemption for boilers serving as control devices to those controlling gaseous streams subject to Parts 60 and 61.

Response: The EPA agrees with the commenter and has incorporated the suggested revisions to §63.7510(a)(2)(ii) and §63.7521(f)(2). Additionally, we have incorporated an exemption for units subject to regulation under 40 CFR part 65. 40 CFR 65.7510(a)(2)(ii) reads as follows: "If gaseous fuels other than natural gas, refinery gas, or other gas 1 fuels are co-fired with other fuels and those gaseous fuels are subject to another subpart of this part, part 60, part 61, or part 65, you are not required to conduct a fuel analysis of those fuels according to §63.7521 and Table 6 to this subpart." 40 CFR 65.7521(f)(2) has also been revised accordingly.

Commenter Name: Felix Mestey, on behalf of Donald R. Schregardus

Commenter Affiliation: Clean Air Act Services Steering Committee, Department of Defense (DoD)

Document Control Number: EPA-HQ-OAR-2002-0058-3427

Comment Excerpt Number: 2

Comment: The text at §63.7510 does not clearly identify that the requirements (e.g., emissions limits, operating limits, performance testing, fuel analysis, establishing operating limits, and demonstrating continuous compliance) in the other tables do not apply to gas 1 units, there is opportunity for confusion and differences in interpretation. Clarification that the requirements in the other tables do not apply to gas 1 units would eliminate any confusion regarding applicability and allow the regulated community to consistently achieve compliance. For example, Table 6 to Subpart DDDDD does not specifically state that gas 1 units are exempt from its requirements.

However, the rule clearly exempts gas 1 units from the requirements in Table 6 to Subpart DDDDD in §63.7521(a) [page 77 FR 80632] which states: "... *Gaseous and liquid fuels are exempt from the sampling requirements in paragraphs (c) and (d) of this section and Table 6 of this subpart.*" As such, gas 1 units are not subject to Table 6 requirements.

In the preamble to the proposed rule revision, the first paragraph under *III. Summary of This Proposed Rule, D. What emission limits and work practice standards must I meet?* [Page 77 FR 80600] states: "*You must meet the emission limits presented in Table 1 of this preamble for each subcategory of units listed in the table. This proposed rule includes 17 subcategories, which are based on unit design. New and existing units in 3 of the subcategories would be subject to work practices standards in lieu of emission limits for all pollutants. Numeric emission limits are being proposed for new and existing sources in each of 14 subcategories, which are shown in Table 1 of this preamble.*" Tables 1 and 2 do not address new or existing boilers or process heaters designed to burn natural gas, refinery gas or other gas 1 fuels. As such, gas 1 units are not subject to Tables 1 and 2 emission limits, but are instead subject to work practice standards in lieu of emission limits for all pollutants.

Additionally in the preamble, the second paragraph under *III. Summary of This Proposed Rule, D. What emission limits and work practice standards must I meet?* [Pages 77 FR 80600-80601] goes on to state: "... *If your unit is a metal process furnace, limited-use unit, or Gas 1 unit (that is, it combusts only natural gas, refinery gas, or other clean gas that meets the fuel specification, with limited exceptions for gas curtailments and emergencies), your unit is subject to a work practice standard that requires an annual tune-up in lieu of emission limits.*" Thus, Tables 1 and 2 emission limits do not apply to gas 1 units.

The rule at §63.7510 [Page 80630] states that "*(a) For affected sources that are required to or elect to demonstrate compliance with any of the applicable emission limits in Tables 1 or 2 of this subpart through performance testing, your initial compliance requirements include all the following: ...*" However, as stated above, the preamble identifies that Tables 1 and 2 do not apply to gas 1 units.

Regarding the operating limits, testing, and initial compliance requirements in the preamble to the proposed rule revision, the second paragraph under item (9) [Page 76 FR 80603] states: "*These operating limits do not apply to owners or operators of boilers or process heaters having a heat input capacity of less than 10 MMBtu/hr or boilers or process heaters of any size which combust natural gas or other clean gas, metal process furnaces, or limited-use units. Instead, if requested, owners or operators of such boilers and process heaters shall submit to the delegated authority or the EPA, as appropriate, documentation that a tune-up meeting the requirements of this final rule was conducted. ...*" As such, the operating limits do not apply to gas 1 units.

Clarify that the emission limits, operating limits, and requirements for performance testing, fuel analysis, establishing operating limits, and demonstrating continuous compliance as identified in the tables to this subpart do not apply to gas 1 units by adding IP (a)(6) to §63.7510 as follows:

§63.7510 What are my initial compliance requirements and by what date must I conduct them?

(1) Gas 1 units (e.g., those meeting the definition of unit designed to gas 1 subcategory) are exempt from the emission limits, testing, fuel analyses, and initial compliance requirements of Tables 1, 2, 4, 5, 6, 7, and 8 of this subpart.

Response: The EPA disagrees with the commenter. First, it is the EPA's intent that the requirements referenced in Tables 1 and 2 (and new Table 11) apply only to the unit categories identified in each table. The header for Table 4 has been revised to clarify that it applies only to units complying with numerical emission limits in Tables 1 and 2 (and new Table 11), which are only required for the unit categories identified in Tables 1 and 2 (and 11). The performance testing, fuel analysis, operating limits, and continuous compliance requirements of Tables 5 through 8 only apply to units subject to emission limits as outlined under 40 CFR 63.7510.

40 CFR 63.7510(a) specifically applies to "affected sources that are required to or elect to demonstrate compliance with any of the applicable emission limits in Tables 1 or 2 of this subpart through performance testing". Furthermore, 40 CFR 63.7510(b), (c), and (d) also specifically identify affected sources that demonstrate compliance with the applicable emission limits in Tables 1 and 2, including carbon monoxide and PM limits. Finally, 40 CFR 63.7510(e) and (g) specify the initial compliance requirements for existing and new or reconstructed sources not subject to the emissions limits in Tables 1 and 2.

Therefore, the EPA believes that it is clear that the emission limits, performance testing, fuel analysis, operating limits, and performance evaluation requirements of 40 CFR 7510(a), (b), (c), and (d), including the referenced requirements of Tables 1, 2, 4, 5, 6, 7, and 8, do not apply to gas 1 units.

Commenter Name: Samuel H. Bruntz

Commenter Affiliation: Alcoa Power Generating, Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3755-A1

Comment Excerpt Number: 1

Comment: There is Confusing language with respect to single type of fuel, co-fired with natural gas. Proposed regulation 63.7510 (a)(2)(i) specifies that, for sources that burn a single type of fuel, a fuel analysis is not required. This proposed regulation further specifies that units that use supplemental fuels only for startup, shutdown, or transient flame stability purposes still qualify as affected sources that use a single *type* of fuel if the supplemental fuel is not subject to the fuel analysis requirements under § 63.7521 and Table 6 to this subpart. Natural gas is not subject to the fuel analysis requirements of § 63.7521. Since that is the case. EPA seems to have recognized that natural gas is a fuel that is not expected to contribute to halogen or heavy metal emissions.

Alcoa-Warrick occasionally co-fires natural gas with coal. Since natural gas is not subject to the fuel analysis requirements of § 63.7521~ the single type of fuel burned exemption should not be restricted to start-up, shutdown, or transient flame stability maintenance purposes.

Accordingly, Alcoa-Warrick requests that §63.7510 (a)(2)(i) be amended, as follows:

"For affected sources that burn a single type of fuel, you are not required to conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to § 63.7521 and

Table 6 to this subpart. For purposes of this subpart, units that use a supplemental fuel ~~only for startup, unit shutdown, and transient flame stability purposes~~, still qualify as affected sources that burn a single type of fuel, ~~if and~~ the supplemental fuel is not subject to the fuel analysis requirements under § 63.7521 and Table 6 to this subpart.

Response: We disagree with the commenter to exempt all uses of supplemental fuels and not just for startup, shutdown, or transient flame stability purposes.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 126

Comment: The last two sentences of proposed §63.7510(b) are unclear and should be clarified as follows.

The fuels described in paragraph (a)(2)(i) ~~and (ii) through (iii)~~ of this section are exempt from these fuel analysis and operating limit requirements. ~~The fuels described in paragraph (a)(2)(iii) of this section are exempt from the chloride fuel analysis and operating limit requirements.~~ Boilers and process heaters that use a CEMS for mercury or hydrogen chloride are exempt from the performance testing and operating limit requirements specified in paragraph (a) of this section ~~for the HAP for which CEMS are used.~~

Response: The EPA acknowledges the commenter's concerns and has revised 40 CFR 63.7510(b) for clarification as follows:

"The fuels described in paragraph (a)(2)(i) ~~and (ii) through (iii)~~ of this section are exempt from these fuel analysis and operating limit requirements. The fuels described in paragraph (a)(2)(iii) of this section are exempt from the chloride fuel analysis and operating limit requirements. Boilers and process heaters that use a CEMS for mercury or hydrogen chloride are exempt from the performance testing and operating limit requirements specified in paragraph (a) of this section for the HAP for which CEMS are used."

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 127

Comment: The last sentence of proposed §63.7510(d) seems out of place and thus is unclear. It should be deleted, since the exception is more appropriately included in §63.7525(b).

"§63.7595" in proposed §63.7510(g) should be "§63.7495".

Response: The EPA agrees with the commenter and has made the suggested revisions to §63.7510(d).

Commenter Name: Russell A. Wozniak
Commenter Affiliation: The Dow Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3449-A1
Comment Excerpt Number: 40

Comment: Dow notes the following incorrect references in EPA's proposed rule:

21. Incorrect Reference in 63.7510(g) - The reference to Section 63.7595 should be to 63.7495.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 127.

Commenter Name: Matthew Todd
Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)
Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2
Comment Excerpt Number: 128

Comment: Proposed §63.7515(b) appears duplicative of the first part of §63.7515(c) and is therefore confusing and likely unnecessary. Any duplication and inconsistencies between §63.7515(b) and (c) should be eliminated.

Response: The EPA agrees with the commenter. We have removed the redundant requirements of 40 CFR 63.7515(b) and revised 40 CFR 63.7515(c) to clarify that if your performance tests for a given pollutant for at least 2 consecutive years show that your emissions are at or below 75 percent of the emission limit (or, in limited instances as specified in Tables 1 and 2 to this subpart, at or below the emission limit) for the pollutant, and if there are no changes in the operation of the individual boiler or process heater or air pollution control equipment that could increase emissions, you may choose to conduct performance tests for the pollutant every third year. Each such performance test must be conducted no more than 37 months after the previous performance test.

Commenter Name: Matthew Todd
Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)
Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2
Comment Excerpt Number: 129

Comment: Proposed §63.7515(f) calls for monthly fuel analyses, where fuel analysis is being used to demonstrate compliance. It is unclear what "monthly" means and this should be clarified. We suggest the language relative to "monthly" from the proposed §65.280(b) part 65 subpart H (Uniform Standard General Provisions)⁵¹ be added to §63.7515(f), including the revisions we suggested in Comment II.9.E.2 above, as follows.

(f) If you demonstrate compliance with the mercury, hydrogen chloride, or total selected metals based on fuel analysis, you must conduct a monthly fuel analysis according to § 63.7521 for each type of fuel burned that is subject to an emission limit in Table 1 or 2 to this subpart. You may comply with this monthly requirement by completing the fuel analysis any time within the

calendar month as long as the analysis is separated from the previous analysis by at least 14 calendar days. If you burn a new type of fuel, you must conduct a fuel analysis before burning the new type of fuel in your boiler or process heater. You must still meet all applicable continuous compliance requirements in § 63.7540. If 12 consecutive monthly fuel analyses demonstrate 75% or less of the compliance level, you may decrease the fuel analysis frequency to quarterly for that specie. If any quarterly sample exceeds 75% of the compliance level or you begin burning a new type of fuel, you must return to monthly monitoring for that specie, until 12 months of fuel analyses again are less than 75 % of the compliance level. ~~If 12 consecutive monthly fuel analyses demonstrate compliance, you may request decreased fuel analysis frequency by applying to the EPA Administrator for approval of alternative monitoring under § 63.8(f).~~

Response: The EPA agrees with the clarifications suggested by the commenter and has revised 40 CFR 63.7515(f), now (e), as follows:

"If you demonstrate compliance with the mercury, hydrogen chloride, or total selected metals based on fuel analysis, you must conduct a monthly fuel analysis according to §63.7521 for each type of fuel burned that is subject to an emission limit in Table 1, 2, or 11 to this subpart. You may comply with this monthly requirement by completing the fuel analysis any time within the calendar month as long as the analysis is separated from the previous analysis by at least 14 calendar days. If you burn a new type of fuel, you must conduct a fuel analysis before burning the new type of fuel in your boiler or process heater. You must still meet all applicable continuous compliance requirements in §63.7540. If 12 consecutive monthly fuel analyses demonstrate 75% or less of the compliance level, you may decrease the fuel analysis frequency to quarterly for that fuel. If any quarterly sample exceeds 75% of the compliance level or you begin burning a new type of fuel, you must return to monthly monitoring for that fuel, until 12 months of fuel analyses again are less than 75 % of the compliance level."

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 152

Comment: Proposed §63.7515(g) requires that after the initial testing you report "the results of performance tests and the associated initial fuel analyses within 90 days after the completion of the performance tests." However, this section deals with subsequent testing, not initial, so §63.7515(g) should be revised by removing the word "initial". Furthermore, as discussed in Comment II.10.B.4 above, subsequent performance test reporting should be required on the same schedule as the periodic reports.

Response: The EPA agrees with the commenter and has revised 40 CFR 63.7515(g) accordingly.

Commenter Name: Samuel H. Bruntz

Commenter Affiliation: Alcoa Power Generating, Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3755-A1

Comment Excerpt Number: 2

Comment: There is conflicting language with respect to fuel analysis requirements.

§63.7510 (a)(2)(i) as presently proposed seems to conflict with 63.7520 (c), which requires that fuels with the highest chlorine and mercury content must be burned during the performance tests. To eliminate this conflict in both regulations, Alcoa-Warrick suggests that 63.7520 (c) be amended as follows:

“You must conduct performance tests at representative operating load conditions while burning the type of fuel or mixture of fuels that has the highest content of chlorine and mercury , and you must demonstrate initial compliance and establish your operating limits based on these performance tests. These requirements could result in the need to conduct more than one performance test. *The requirement to conduct performance tests while burning fuels with the maximum amount of chlorine and mercury is not applicable for units that burn a single type of fuel, as specified by 63.7510(a)(2)(i), provided the performance tests are conducted at representative operating loads for the single type of fuel burned in the unit.*”

Response: We disagree that 63.7520(c) needs to be revised. §63.7520(c) states "while burning the type of fuel ... that has the highest content of ...". It does not state that a unit burning a single fuel type must conduct the test with the maximum content for that fuel type.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 130

Comment: Proposed §63.7520(e) specifies how to convert performance test values to pounds per million BTU. However, the proposed language only makes the procedure applicable to the initial performance test. The word "initial" should be deleted from §63.7520(e) as the procedure applies for all performance tests.

Response: The EPA thanks the commenter for their input and has revised 40 CFR 63.7520(e) accordingly.

Commenter Name: Peter Pagano

Commenter Affiliation: American Iron and Steel Institute (AISII)

Document Control Number: EPA-HQ-OAR-2002-0058-3490-A1

Comment Excerpt Number: 16

Comment: Sources Using Process Gases subject to Parts 60, 61, and 63 should be exempt from conducting the gas 1 fuel specification analysis.

The Boiler MACT currently provides that operators are not required to conduct the mercury fuel specification analyses for gaseous fuels that are natural gas, refinery gas, or otherwise subject to another subpart of part 63. EPA also should exempt those sources using process gases that

otherwise are regulated under Parts 60 and 61 from conducting a fuel specification analysis. Specifically, section 63.7521(f)(2) should be amended to read:

You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for gaseous fuels for units that are subject to another subpart of this part, part 60, or part 61.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 114.

Commenter Name: Dave Copeland, Manager, Air Quality, Corporate Safety and Environmental Services

Commenter Affiliation: Praxair Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3437-A2

Comment Excerpt Number: 2

Comment: We do, however, have some concerns in regards to timing in needing EPA "approval" of the fuel analysis plan as specified in 63.7521(g). This "approval" authority should be delegated to the local authority (e.g. Title V permit writer) to help ensure that it can be obtained in a timely manner.

Alternatively, the "approval" section could be taken out altogether to read as follows:

(g) You must develop and submit a site-specific fuel analysis plan for other gas 1 fuels to the EPA Administrator/or for review ~~and approval~~ according to procedures and requirements in paragraphs (g)(1) and (2) of this section.

Response: 63.7521(g) has been revised in the final to be consistent with the revision to 63.7521(b) to remove the requirement for EPA approval unless an alternative method other than those in Table 6 is requested. 63.7521(g) is revised to read:

(g) You must develop a site-specific fuel analysis plan for other gas 1 fuels according to the following procedures and requirements in paragraphs (g)(1) and (2) of this section.

(1) If you intend to use an alternative analytical method other than those required by Table 6 to this subpart, you must submit the fuel analysis plan to the Administrator for review and approval no later than 60 days before the date that you intend to conduct the initial compliance demonstration described in §63.7510.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 131

Comment: Proposed §63.7521(i) is missing the word "other" and should say:

You must determine the concentration in the fuel of mercury, in units of $\mu\text{g}/\text{cu m}$, dry basis, of each sample for each other gas 1 fuel type according to the procedures in Table 6 to this subpart.

Response: The EPA agrees with the commenter and has revised 40 CFR 63.7521(i) accordingly.

Commenter Name: Dean C. DeLorey

Commenter Affiliation: The Amalgamated Sugar Company LLC (TASCO)

Document Control Number: EPA-HQ-OAR-2002-0058-3522-A1

Comment Excerpt Number: 17

Comment: The rule calls for conducting performance tests and fuel sampling but does not describe how the fuel sampling results are to be correlated to performance test results. The rule is very prescriptive in determining maximum input levels for mercury, chlorine, and total selected metals, but does not explain how these levels relate to the performance test results. Please clarify.

Response: We disagree that the rule does not explain how these fuel sampling results relate to the performance test results. §63.7540(a)(4) and (a)(6) both states "If you demonstrate compliance with an applicable hydrogen chloride (or mercury) emission limit through performance testing and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum chlorine (mercury) input using Equation 7 of §63.7530. If the results of recalculating the maximum chlorine input using Equation 7 of §63.7530 are greater than the maximum chlorine input level established during the previous performance test, then you must conduct a new performance test.." The maximum chlorine and mercury input levels are what determines if a performance test is needed if the fuel type or mixture is changed.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 90

Comment: Emissions averaging should be allowed for units complying with TSM emission limits. Section 63.7522 does not allow emissions averaging for TSM, but as the compliance provisions (either stack testing or fuel sampling and analysis) are essentially the same as those for HCl and Hg, there is no reason why it should not be allowed. EPA allows emissions averaging for TSM in the final MATS rule (see §63.10009).

Response: We agree with the commenter that emission averaging be allowed for demonstrating compliance with the TSM emission limit. Because PM is used as a surrogate for TSM and TSM limits were proposed as an alternate to the PM limits, §63.7522 has been revised in the final rule to include TSM to be consistent with the requirements for PM.

Commenter Name: Steve Gossett

Commenter Affiliation: Eastman Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3669-A2

Comment Excerpt Number: 49

Comment: Emissions averaging should be allowed for compliance with the optional TSM limit.

With no justification for doing so, EPA has proposed to exclude use of the emissions averaging option to comply with the proposed total selected metals (TSM) emission limits. EPA included TSM in the emissions averaging provisions for the Utility MACT (§63.10009) and Eastman is aware of no difference that would justify treating industrial and institutional boilers differently. Accordingly, Eastman requests that EPA allow the emissions averaging option for industrial and institutional facilities to comply with the proposed total selected metals (TSM) emission limits.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 90.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 78

Comment: At §63.7522(b)(1), EPA has added a new provision stating "You may not include in an average units using a CEMS or PM CPMS for demonstrating compliance, even if the use of a CEMS or PM CPMS is optional." This restriction on use of CEMS for emissions averaging has been proposed with no explanation as to EPA's logic for this restriction. It is in direct conflict with the emissions averaging provisions in the recently finalized MATS rule (See §63.10009). EPA should provide industrial facilities with at least the same flexibility it provides electric utilities. This restriction would discourage the use of CEMS (where they are optional) in cases where a source elects to utilize emissions averaging. It also restricts emissions averaging among fossil fuel-fired units to those less than 250 MMBtu/hr, due to the PM CPMS restriction. EPA should not discourage use of CEMS as a compliance option or limit emissions averaging to small sources using stack testing and parameter monitoring to comply with the rule. To the contrary, EPA should provide sources that use a continuous direct measure of emissions with more flexibility, not less, than sources using periodic stack testing and parameter monitoring.

Response: The EPA acknowledges the commenter's concerns. The EPA believes that emissions averaging subject to certain unit eligibility criteria in the rule, including existing units within the same subcategory, can provide a cost-effective, flexible, environmentally-friendly means of demonstrating compliance. The rule has been revised to allow units that rely on CEMS for compliance demonstrations to be able to participate in emissions averaging. The EPA believes that the data certainty provided by units that use CEMS would be ideal for emissions averaging and the flexibility and cost-effectiveness it offers. We have removed the emissions averaging exclusion for units using a CEMS or PM CPMS in 40 CFR 63.7522(b)(1) in the final rule.

Commenter Name: Tangela Niemann

Commenter Affiliation: Texas Commission on Environmental Quality (TCEQ)

Document Control Number: EPA-HQ-OAR-2002-0058-3594-A3

Comment Excerpt Number: 7

Comment: The use of the term "delegated authority" in the emissions averaging provisions in §63.7522 and in the emissions credit provisions in §63.7533 may create confusion within the regulated community. It is unnecessary for the EPA to use a separate term within these sections of the rule. If a state accepts delegation of the final version of the proposed new Subpart DDDDD, using the term "administrator" would apply equally to §63.7522 and §63.7533 as it

does to the other provisions of the rule. If a state has not received delegation for the NESHAP rule, not only would the state have no authority to issue an approval under §63.7522 and §63.7533, the state is under no obligation to review the plans on the EPA's behalf. In the recently finalized 40 CFR 63 Subpart 63 NESHAP rule for utilities, the EPA made similar changes in response to the TCEQ's comments.

Response: The EPA agrees with the commenter and has replaced "delegated authority" with "administrator." The part 63 General Provisions definitions in part 63.2 defines "Administrator" to mean the Administrator or authorized representative (e.g. delegated state).

Commenter Name: Tangelia Niemann

Commenter Affiliation: Texas Commission on Environmental Quality (TCEQ)

Document Control Number: EPA-HQ-OAR-2002-0058-3594-A3

Comment Excerpt Number: 8

Comment: The EPA revised the emissions averaging approach for the utility NESHAP rule to only require the emissions averaging implementation plans to be submitted for review and approval upon request by the administrator. The TCEQ supports this change and requests that the EPA make the same change to §63.7522 and §63.7533. This option will help streamline the review process for the implementation plans and the administrator, or the delegated authority if a state receives delegation, and allow for the review process to prioritize review of the plans rather than require review and approval of all plans. As discussed elsewhere in these TCEQ comments, the TCEQ also suggests the EPA review §63.7522 and §63.7533 to determine if revisions to the rule are necessary to eliminate the need for case-by-case review and approval of the implementation plans.

Response: The EPA agrees with the commenter and has revised 40 CFR 63.7522 and 40 CFR 63.7533 to only require the emissions averaging implementation plans to be submitted for review and approval upon request by the administrator.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 142

Comment: Section 63.7522(d) states, "The averaged emissions rate from the existing boilers and process heaters participating in the emissions averaging option must be in compliance with the limits in Table 2 to this subpart at all times following the compliance date specified in § 63.7495." Please clarify that compliance must be met "at all times that the unit is subject to numeric emission limits" (emphasis added) as numeric emission standards do not apply during periods of startup and shutdown.

The same change is needed for §63.7533 (e) with respect to compliance with the output based limits.

The same change is needed for §63.7540(a)(8)(ii), which specifies that if you are using a CO CEMS you must maintain a CO emissions level below or at your Table 1 or 2 limit at all times (emphasis added).

Response: The EPA agrees with the commenter and has revised §63.7522(d), §63.7533 (e), and §63.7540(a)(8)(ii) in the final rule to clarify limits do not apply during startup and shutdown. See the response to comment EPA-HQ-OAR-2002-0058-3685-A2, excerpt 39.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 159

Comment: Section 63.7522(d) states, "The averaged emissions rate from the existing boilers and process heaters participating in the emissions averaging option must be in compliance with the limits in Table 2 to this subpart at all times following the compliance date specified in § 63.7495." Please clarify that compliance must be met "at all times that the unit is subject to numeric emission limits" (emphasis added) as numeric emission standards do not apply during periods of startup and shutdown.

The same change is needed for § 63.7533 (e) with respect to compliance with the output based limits.

The same change is needed for § 63.7540(a)(8)(ii), which specifies that if you are using a CO CEMS you must maintain a CO emissions level below or at your Table 1 or 2 limit at all times (emphasis added).

Response: See the response to comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 142.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 69

Comment: *The CEMS Location Requirement Should be Clarified*

Proposed § 63.7525(a)(1) requires that a CO CEMS monitor the CO level at the "outlet" of the boiler or process heater. Such CO monitors are also required to satisfy the requirements of PS 4, 4A or 4B. It is not possible to certify any gas monitor according to applicable Performance Specifications if the monitor is located at the outlet to the boiler. This inability to certify is caused by stratification of gases at the boiler/process heater outlet. In addition, for units equipped with add-on controls or flue gas recirculation systems the "outlet" could be construed to be either before or after these controls. Since these systems may impact the CO level, the measurement must be after any controls or recirculation (i.e., just before the gas is released to the atmosphere. EPA should revise the last sentence of § 63.7525(a)(1) as follows:

If a CO CEMS is used, the carbon monoxide level shall be monitored at the outlet of the boiler or process heater, after any add-on controls or flue gas recirculation system and before release to the atmosphere.

The installation of the monitor in the stack or breeching leading to the stack would not have any impact on determining the compliance status of the source since the CO data will have to be corrected to 3% O₂, thus negating the impact of any dilution of the stack gas due to leaks in the system.

Response: The EPA thanks the commenter for their input and has revised 40 CFR 63.7525(a)(1) accordingly to clarify the CO CEMS monitoring location is after any add-on controls or recirculation and before release to atmosphere.

Commenter Name: David A. Buff, Golder Associates Inc.

Commenter Affiliation: Florida Sugar Industry (FSI)

Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1

Comment Excerpt Number: 42

Comment: For units equipped with add-on controls or flue gas recirculation systems, the "outlet" could be construed to be either before or after these controls. Since these systems may impact the CO level, the measurement must be after any controls or recirculation (i.e., just before the gas is released to the atmosphere). EPA should revise the last sentence of §63.7525(a)(1) by adding the underlined language, to read as follows:

If a CO CEMS is used, the carbon monoxide level shall be monitored at the outlet of the boiler or process heater, after any add-on controls or flue gas recirculation system and just before release to the atmosphere.

The installation of the monitor in the stack would not have any impact on determining the compliance status of the source since the CO data will have to be corrected to 3% O₂, thus negating the impact of any dilution of the stack gas due to leaks in the system.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 69.

Commenter Name: John S Williams

Commenter Affiliation: Maine Pulp & Paper Association (MPPA)

Document Control Number: EPA-HQ-OAR-2002-0058-3466-A1

Comment Excerpt Number: 5

Comment: CEMS need to be installed in stacks, not at the boiler outlet. Section 7525 needs to be corrected to require the CEMS to be installed in a boiler stack (or boilers outlet may be used for boilers with shared stacks).

"63. 7525 The oxygen analyzer system or the CO CEMS must be installed by the compliance date specified in § 63.7495. If a CO CEMS is used, the carbon monoxide level shall be monitored at the outlet of the boiler or process heater."

Response: See the response to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 69 for clarification of location of CEMS.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 132

Comment: Proposed §63.7525(b) starts "If your boiler or process heater has an average annual heat input rate greater than 250 MMBtu/hr from solid fossil fuel and/or residual oil, and you demonstrate compliance with the PM limit instead of the alternative total selected metals limit..." This leaves unclear whether this requirement applies to heavy oil fuels that are not residual oil. We recommend the term "residual oil" be changed to "heavy liquid" in proposed §63.7525(b) to clarify this issue.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 36.

Commenter Name: David A. Buff, Golder Associates Inc.

Commenter Affiliation: Florida Sugar Industry (FSI)

Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1

Comment Excerpt Number: 27

Comment: EPA should also specify how a 30-day rolling average for the operating parameter limits is calculated, indicating that the 30-day rolling average includes the previous 720 hours of valid operating data. EPA should make clear that valid data exclude hours during startup and shutdown as well as unit down time. This clarification will be helpful with the implementation of the final rule. For example, when a unit is down for an outage, the 30-day calculation would not include the outage. Specification of the minimum number of readings assures that the 30-day average concept is not undermined.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3504-A1, excerpt 27.

Commenter Name: Samuel H. Bruntz

Commenter Affiliation: Alcoa Power Generating, Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3755-A1

Comment Excerpt Number: 3

Comment: Proposed regulation 63.7510 (a)(3) requires that operating limits must be established, according to 63.7530 and Table 7 to *this* subpart. 63.7530(a) also conflicts with 63.7510 (a)(2)(i), in that it requires that .. You must demonstrate initial compliance with each emission limit that applies to you by conducting initial performance tests and fuel analyses ... "

Alcoa- Warrick suggests that this conflicting language be corrected, as follows:

63.7530(a) "You must demonstrate initial compliance with each emission limit that applies to you by conducting initial performance tests and fuel analyses and establishing operating limits,

as applicable. according to § 63.7520, paragraphs (b) and (c) of this section, and Tables 5 and 7 to this subpart. *The requirement to conduct a fuel analysis is not applicable for units that burn a single type of fuel, as specified by 63.7510(a)(2)(i).* If applicable, you must also install..."

Response: The EPA thanks the commenter for their input and has revised 40 CFR 63.7530(a) accordingly.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 134

Comment: Finally, the rule does not make clear the significance of a valid hour of data, although it does talk about "valid" data in several places. Thus, we recommend addition, at §63.7530(c), of text that indicates that only valid hours of data may be used to generate valid data.

Response: §63.7525(d)(1) states: "The continuous parameter monitoring system must complete a minimum of one cycle of operation every 15-minutes. You must have a minimum of four successive cycles of operation, one representing each of the four 15-minute periods in an hour, to have a valid hour of data." The definition of "10-day rolling average" and "30-day rolling average" have been revised and include the phrase "hours of valid operating data."

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 135

Comment: Proposed §§63.7530(g) and 63.7540(c) requires that you conduct monthly mercury analyses if your other gas 1 could vary above the maximum mercury criterion for being other gas 1. The word "could" is ambiguous, since anything "could" happen. This wording should be revised to only require monthly monitoring if the maximum mercury specification can "reasonably be expected" to be exceeded. Additionally, since the hydrogen sulfide criterion for other gas 1 gases has been removed, mention of hydrogen sulfide should be removed from §§63.7530(g) and 63.7540(c).

Response: The mention of hydrogen sulfide has been removed from §63.7530(g) and §63.7540(c).

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 136

Comment: Proposed §§63.7530(h) and 63.7540(d) appear to apply all work practice requirements in Table 3 to BPH subject to the numerical emission limits in Tables 1 or 2. This should be clarified by specifying in §§63.7530(h) and 63.7540(d) that only Item 5 of Table 3 applies to startup and shutdown periods.

Response: The EPA agrees with the commenter and has modified 63.7530(h) and 63.7540(d) accordingly.

Commenter Name: Tangelia Niemann

Commenter Affiliation: Texas Commission on Environmental Quality (TCEQ)

Document Control Number: EPA-HQ-OAR-2002-0058-3594-A3

Comment Excerpt Number: 11

Comment: The EPA should use the term *efficiency credit* in §63.7533 rather than refer to the credit as an *emission credit*. The approach in §63.7533 prorates emission test results based on implemented efficiency measures that result from energy input savings before the results are compared to the emission standards, which is similar to approaches used for combined heat and power applications. *Efficiency credit* is a more accurate terminology for the approach the EPA has proposed. Additionally, use of the term *emission credits* may create confusion with terminology used in emissions banking and trading programs, such as *emission reduction credit*.

Response: The EPA agrees with the commenter that the term "efficiency credit" is more accurate. We have changed the term "emission credit" to "efficiency credit" in §63.7533.

Commenter Name: Jessica Bridges

Commenter Affiliation: United States Clean Heat & Power Association (USCHPA)

Document Control Number: EPA-HQ-OAR-2002-0058-3501-A1

Comment Excerpt Number: 24

Comment: 40 CFR 63.7533(c), (c)(1)(i), and (c)(3), Amend these paragraphs to change the date after which energy conservation measures can be used to generate credits from January 14, 2011, to January 1, 2008. January 1, 2008 is the same cut-off date for using a pre-existing energy assessment to satisfy the energy assessment requirement in Table 3 to subpart DDDDD.

We are supportive of this roll back in date from January 14, 2011 to January 1, 2008 for both the use of emission credits obtained from energy conservation measures and for pre-existing energy assessment.

Response: The EPA thanks the commenter for their support. We are maintaining the January 1, 2008 date in the final rule, consistent with the December 2011 proposal.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 137

Comment: Proposed §63.7535(d) could be construed to make activities specified in an applicable monitoring plan and preventive maintenance activities deviations, since it specifically exempts repairs associated with malfunctions and does not mention any other types of repairs or upgrades. This should be clarified by including monitoring plan activities in the list of exceptions that begins §63.7535(d).

Response: The EPA thanks the commenter for their input and has clarified 40 CFR 63.7535(d) accordingly.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 55

Comment: The last sentence of proposed §63.7540(a)(10) states "This requirement does not apply to limited use boilers and process heaters, as defined in § 63.7575." However, the tune-up requirements in (a)(10) do apply to limited use (and other) BPH, but on a different schedule than annually. Proposed §63.7540(a)(11) and (12) reference (a)(10) and establish the tune-up frequency for limited use and other non-annual tune-up situations. Thus, this sentence in §63.7540 should be revised to limit the exception to only the frequency of the tune-up, not the entire tune-up requirement.

Response: The EPA agrees with the commenter and has revised 40 CFR 63.7540(a)(10) to clarify the exception only applies to the frequency of tune-up.

Commenter Name: Kerry Kelly

Commenter Affiliation: Waste Management (WM)

Document Control Number: EPA-HQ-OAR-2002-0058-3681-A2

Comment Excerpt Number: 17

Comment: The reference to §63.7545(g) in §§63.7540(c) and 63.7555(g) is incorrect. The correct reference is §63.7530(g).

Response: The EPA thanks the commenter for their input and has corrected the typo accordingly.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 151

Comment: Proposed §63.7545(e) calls for the NCS to be submitted "before the close of business on the 60th day following the completion of all performance test and/ or other initial compliance demonstrations for the affected source according to § 63.10(d)(2)." At many facilities there will be multiple affected sources, since each new or reconstructed boiler or

process heater is a separate affected source. Therefore, we request and recommend that this sentence be revised to specify the NCS be required 60 days after completion of testing and/or compliance demonstrations for all boilers and process heaters at the facility.

Response: The EPA agrees with the commenter and has clarified 40 CFR 63.7545(e) to define the affected sources.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 154

Comment: The NCS filing criteria need to be clarified. The Notification of Compliance Status filing requirement in §63.7545(e) appears to only apply if you are required to conduct an initial compliance demonstration by §63.7530(a). However, the NCS is the only place that requires certification of compliance for the initial tune-up and for the energy assessment, which are not "compliance demonstrations" under the proposal. Thus, if no compliance demonstrations are required, no certification of the initial tune-ups or of the energy assessment appears to be required by the proposed language. §63.7545(e) should be revised to require filing of an NCS, but only require tune-up and energy assessment certifications if there are no initial performance tests or compliance demonstrations.

Response: The EPA agrees with the commenter and has revised the 40 CFR 63.7545(e) introductory text to add, "If you are not required to conduct an initial compliance demonstration as specified in §63.7530(a), the Notification of Compliance Status must only contain the information specified in paragraphs (e)(1) and (e)(8)."

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 155

Comment: Proposed §63.7545(e)(1) requires reporting in the NCS "a description of add-on controls" for each BPH. We do not believe it serves any purpose to list controls not associated with compliance with this rule (e.g., NO_x and SO_x controls). Thus, we recommend the description of add-on controls be limited to controls that will be relied upon for complying with this rule.

Response: The EPA agrees with the commenter and has revised 40 CFR 63.7545(e)(1) to limit the required description of add-on controls to only controls relied upon for compliance with the rule.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and

Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 146

Comment: Proposed §63.7545(e)(1) requires reporting in the NCS for each BPH a "description of the fuel(s) burned, including whether the fuel(s) were determined by you or EPA through a petition process to be a non-waste under § 241.3, whether the fuel(s) were processed from discarded nonhazardous secondary materials within the meaning of § 241.3." This wording presumes all fuels are secondary materials or processed from nonhazardous secondary materials. As discussed above, gases, the most common fuel type, are almost never secondary materials. Thus, for gases only a description of the fuel should be required. Additionally, for general clarity this phrase should be revised to require reporting of their 241.3 status only if the material being combusted is a secondary material.

Response: §63.7545(e)(1) has been revised to clarify that reporting of 241.3 status is only required if the material being combusted is a secondary material.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 156

Comment: Proposed §63.7545(e)(7) requires reporting of deviation information in the NCS. This requirement is duplicative, since these same deviations must be reported in the initial periodic report. Since the periodic report is the appropriate and normal place for reporting deviations, §63.7545(e)(7) should not be finalized.

Response: We disagree that 63.7545(e)(7) is a duplicative requirement. §63.7545(e)(7) deals with the initial Notification of Compliance Status. Affected units are to be in compliance by the compliance date but have 180 days after to demonstrate compliance and another 60 days after the performance test to submit the Notification. Thus, there may be 240 days in which deviations could happen.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 159

Comment: Proposed §63.7545(e)(8)(i) requires that the NCS contain a certification that the facility "complies with the requirements in §63.7540(a)(10), (11), or (12) to conduct an annual, biennial, or 5-year tune-up as applicable, of each unit." Sources cannot certify compliance with this statement since annual, biennial, or 5-year tune-ups cannot have been completed, since the NCS is required before those tune-ups are due. All a source can certify is that they have completed the required initial tune-up. Thus, proposed §63.7545(e)(8)(i) cannot be finalized.

Response: The EPA acknowledges the commenter's concern. The intent in the proposed rule was to provide a certification statement to specify that the facility following the initial tune-up procedures provided in 63.7540(a)(1). The rule has been revised at 40 CFR 63.7545(e)(8)(i) for clarification as follows, "This facility complies with the required initial tune-up according to the procedures in §63.7540(a)(10)(i) through (a)(10)(vi)."

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 161

Comment: In proposed §63.7545(h)(1) "boilers" should be "boilers and process heaters".

Response: The EPA agrees with the commenter and has revised the rule accordingly.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 163

Comment: Proposed §63.7550(e)(2) requires reporting "the date and time that each CMS was inoperative, except for zero (low level) and high level checks." However, the rule requires CMS to be out of service for other reasons, such as quality assurance checks and preventive maintenance, as detailed in the monitoring plan. Thus, there will be much wasteful reporting of outages that are not deviations or deviation related. We recommend this requirement be revised to exclude reporting of outages needed for compliance with the applicable monitoring plan.

Response: The EPA agrees with the commenter and has revised 40 CFR 63.7550(e)(2) to exclude reporting outages needed for compliance with applicable monitoring plan.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 164

Comment: Proposed §63.7550(e)(8) requires identification of each parameter that was monitored at the affected source for which there was a deviation. It is unclear what this is requesting. Is it asking for identification of the parameter that had the deviation or is it asking for a list of all parameters monitored for that boiler or process heater where the deviation occurred? In either case, it would seem that information is already required in earlier paragraphs and it is unclear (e)(8) serves any purpose. Thus, §63.7550(e)(8) should be deleted as duplicative. If it is not deleted it must be clarified as to what it is requiring. There certainly is no justification for gathering information on anything other than the parameter for which there was a deviation.

Response: The EPA thanks the commenter for their input and has removed the redundant text from 40 CFR 63.7550(e) accordingly.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 165

Comment: Proposed §63.7550(f) deals with affected sources that have obtained a Title V permit. However, affected sources do not obtain Title V permits, facilities do. Thus, §63.7550(f) should be clarified by either replacing "affected source" with "facility" or by referring to "boilers and process heaters that are covered by a Title V permit".

Response: The EPA agrees with the commenter and has revised 40 CFR 63.7550(f) to "boilers and process heaters that have obtained a Title V permit" for clarification.

Commenter Name: Sarah Hedrick

Commenter Affiliation: Verso Paper Corp.

Document Control Number: EPA-HQ-OAR-2002-0058-3537-A2

Comment Excerpt Number: 12

Comment: Section 63.7550(h) requires performance test reports and CEMS RATA tests to be submitted electronically to EPA's WebFIRE database. Since it is likely that many states eventually will be delegated authority, this requirement is overly burdensome and costly for facilities with limited resources. States like Maine already specify that performance test results be submitted in an electronic format. EPA should remove its reporting format requirement from the rule and work more closely with states to develop a universal reporting system that is not costly, does not require redundant, different electronic reporting formats, and that is not problematic and labor-intensive for data entry. As proposed, the rule's requirement is an extra, excessive burden for mills and stack testing vendors. EPA needs to defer any electronic collection of data until the CDX and WebFIRE systems are fully functional, user-friendly, and streamlined with States.

Response: We disagree with the commenter that electronic reporting is overly burdensome because many states will be the delegated authority. States are already delegated the authority to implement EPA rules and the shift from paper to electronic reporting to delegated authorities is not overly burdensome for a number of reasons. First, the tool that sources are required to use for electronically reporting results of stack tests (i.e., the Electronic Reporting Tool (ERT)) has an option to print a report after the required data and information are entered. Thus, a facility will be able to simply print a performance test report from the ERT in order to fulfill any requirement imposed by a delegated authority to submit reports in hard copy. Second, many sources and stack testing companies are already familiar with the ERT and have used the ERT in previously submitting stack test data to the Agency. Furthermore, many facilities are already experienced in electronically submitting reports as a result of the requirements of the Toxic Release Inventory and Greenhouse Gas Reporting Program.

The EPA disagrees with the commenter that the State of Maine already requires electronic reporting which makes the EPA electronic reporting of performance test reports redundant. The State of Maine does not require facilities to submit stack test reports electronically. First, the provision to submit test reports electronically is optional, and second, the optional requirement allows facilities to simply submit a pdf file. This approach allows facilities to fulfill the optional requirement by submitting their information via e-mail. This hardly compares to the electronic reporting system that the Agency has implemented and any suggestion that our approach is redundant with the e-mail approach that is allowed by the State of Maine is incorrect. Our approach is much more robust and provides for easy and quick access to submitted information, thereby making performance test data available for data analyses for regulation development and other analyses. The EPA agrees with the commenter that the EPA should defer any electronic reporting until the CDX and WebFIRE systems are fully functional, user-friendly, and stream-lined with States. However, such systems are currently fully functional and the time is right for implementing electronic reporting. In fact, we have previously incorporated electronic reporting requirements into numerous regulations and affected facilities are successfully submitting the required information to WebFIRE using the CDX data portal. All performance test reports that have been submitted are available to State Air Pollution Control Agencies at all times. Thus, the EPA believes that the electronic reporting is not adversely impacting any State reporting systems, so deferring any electronic collection is not warranted.

Commenter Name: Lee Zeugin and Lauren Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1

Comment Excerpt Number: 42

Comment: The 2011 final rule includes two provisions for electronic reporting. The first requires reporting of “relative accuracy test audit” or “performance test” data for PM CEMS within 60 days to EPA’s Central Data Exchange (“CDX”) using EPA’s Electronic Reporting Tool (“ERT”). 40 C.F.R. § 63.7540(a)(9)(iv). The second requires reporting of “relative accuracy test audit (*i.e.*, reference method) data” and “performance test (*i.e.*, compliance test) data, except opacity data” to CDX using ERT with 60 days of “each performance test.” 40 C.F.R. § 63.7550(h). Both provisions differ from EPA’s proposed rule, which required submission of “test data” within 60 days of each “performance evaluation.” 75 Fed. Reg. 32,0006, 32,059, 32,062.

Response: The EPA has clarified the electronic reporting requirements contained in the 2011 final rule. However, the commenter is mistaken that the electronic reporting provisions in the proposed rule differ from the final rule. Section 63.7550(h) of the final rule specified that both relative accuracy test audit (RATA) data and performance test data were required to be submitted electronically within 60 days after completion of each performance test. EPA believes the reference to relative accuracy test audit data in this paragraph was redundant with the requirement contained in Section 63.750(a)(9)(iv) of the final rule which also required the submission of RATA data within 60 days of completing each CEMS RATA. As a result, we have proposed language in Section 63.7550(h) of the December 23, 2011 proposal to clarify that sources must submit performance test results within 60 days after the date of completing each performance test. The proposed requirement in Section 63.7550(i) to submit relative test audit data within 60 days of completing each performance evaluation remains the same as the requirement contained in Section 63.7540(a)(9)(iv) of the final rule. We believe the proposed

language is consistent with the electronic reporting requirements that were contained in the final rule but add a level of clarity that was absent from the final rule.

Commenter Name: Lee Zeugin and Lauren Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1

Comment Excerpt Number: 45

Comment: UARG appreciates EPA's attempts to revise these provisions. As promulgated, the provision aimed at PM CEMS is not implementable. PM CEMS testing involves neither a "performance test" nor a "relative accuracy test audit." UARG also appreciates the increased specificity regarding reporting of each category of data. For example, UARG agrees that it makes no sense to report relative accuracy test audit data to WebFIRE. However, the new proposed provisions remain flawed. EPA still has not sufficiently explained the need for each category of data, established the consistency of ERT with the applicable substantive reporting requirements, or ensured compliance with CROMERR.

Response: The reporting forms or templates, that would allow the PM CEMS data summaries to be submitted electronically through the CDX (using CEDRI) to WebFIRE, have not been developed. In response to this comment, we have changed the rule to clarify that implementation of the requirement to electronic report semi-annual reports will commence only when the electronic reporting tools (e.g., data submittal templates) and the data submission process are operative. Because the reporting template and data submission process for stack test reports are completed and operational, the requirement to submit stack test reports electronically will be effective on the compliance date.

The EPA disagrees with the commenters that the EPA has not sufficiently explained the need for each category of data. The preamble (76 Fed. Reg. at 80,605) to the proposed revisions explains the use of the data collected by electronic reporting. Additionally, the EPA believes it is important to require the submissions of the 30 day rolling average data in the semi-annual reports because these data serve multiple useful purposes and are important in: Ensuring continued compliance performance of process and control device operations and providing sources with data to support compliance certifications, providing the sources and the agency with data representing variability of control measures for support of future (e.g., 8 year) regulatory reviews and updates, and identifying the best performing units and control approaches making more manageable and less burdensome future information data collection projects. Thus, the EPA will retain the electronic reporting of 30-day rolling averages' requirements in the rule.

We disagree that with commenter's assertion that the EPA "still has not sufficiently established the consistency of ERT with the applicable substantive reporting requirements". To the contrary, the proposed rule clearly states that only source test data collected using test methods supported by ERT are required to be reported electronically. In this manner we have ensured that only reporting requirements supported by ERT are subject to the requirement to report such information electronically. In addition, the EPA has worked closely with stack testing companies to develop and improve the ERT to ensure that that data elements required in ERT are compatible with the data that is typically collected during a stack test and reported as part of the stack test report.

The EPA also disagrees with the statement that these electronic reporting provisions are not in compliance with CROMERR. The ERT, in conjunction with the Central Data Exchange (CDX) (which is the EPA portal for reporting electronic data), the requirement to register as a user of the CDX, and the requirement to use the reporting interface (Compliance and Emissions Data Retrieval Interface (CEDRI)). In order to submit ERT files through CDX/CEDRI, one must be a registered user of CDX. The CDX registration process ensures compliance with CROMERR through use of an identity validation process that meets the CROMERR requirements. As a result, submitting ERT files through CDX is fully compliant with CROMERR.

Commenter Name: Samuel H. Bruntz

Commenter Affiliation: Alcoa Power Generating, Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3755-A1

Comment Excerpt Number: 17

Comment: 63.7550 (h),(i) and (j) requires submittal of test data and CPMS data using EPA's Webfire database. Alcoa -Warrick understands that the Webfire database is slightly more user friendly than the Electronic Reporting Tool. However, stack test contractors Alcoa Warrick uses have indicated that the Webfire database is still difficult to learn and tedious to complete. Alcoa" Warrick understands that EPA is working on improvements to this database, and will be discussing those improvements in the March SES conference. APGJ thus recommends that, until EPA revises the Webfire database in a manner that makes it more user friendly, proposed regulation 63.7550 (h) (i) and G) be amended by allowing data submittal in hard copy form.

Response: Under the EPA's proposed electronic data reporting process, facilities do not need to "learn and complete" WebFIRE. WebFIRE is an EPA maintained Oracle data base in which data that has been submitted electronically is automatically stored. Facilities simply need to upload ERT files using the user friendly data portal called CEDRI. While it is true that the EPA continues to make improvements to the ERT to address issues that users have identified, the ERT has been required to be used in previous data collection activities and is currently required in recent rulemakings. Our experience is that stack testing companies are finding that ERT is user friendly and that it provides a workable and reasonable format by which to document the results of stack tests. This is supported by the fact that facilities are currently using ERT and the CEDRI data reporting portal to successfully upload ERT files to WebFIRE. As such, the EPA believes that the electronic submittal of performance test reports do not need to be deferred and that paragraphs (h), (i), and (j) of section 63.7550 do not need to be revised.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 139

Comment: EPA has included a new requirement in the December 2011 proposed Boiler MACT that will be excessively burdensome to industry. This requirement is not justified, and is not discussed in the preamble. New section 63.7550 (j) states:

"Within 60 days after the reporting periods ending on March 31, June 30, September 30, and December 31, you must transmit quarterly reports to EPA's WebFIRE database by using the

Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (www.epa.gov/cdx). For each reporting period, the quarterly reports must include all of the calculated 30 day rolling average values based on the daily CEMS (CO and Hg) and CPMS (PM CPMS output, scrubber pH, scrubber liquid flow rate, scrubber pressure drop) data."

EPA has not yet built this interface, so industry has had no opportunity to provide comment on its usability or the burden it will impose. This addition to the rule was incorrectly characterized as a technical correction in Table 3 of the Preamble. We have had no opportunity to evaluate the compatibility of existing data acquisition systems with this new EPA system. There is no reason for EPA to require the submittal of all of a facility's monitoring data. EPA has provided no justification for this new requirement. Facilities will provide certifications on their semi-annual compliance reports that they have performed the required monitoring and will provide information on any deviations from monitoring requirements or established parameter ranges. Additional parametric monitoring reports provide no useful purpose, environmental or otherwise, to anyone and are an additional administrative burden on operating facilities. EPA has already increased reporting burden by requiring all test data to be submitted electronically through the ERT, which continues to be revised and updated due to various flaws. We expect that this CEDRI interface would suffer from the same issues and may not even be available when facilities must submit their first of these quarterly reports. It is unreasonable to put sources at risk of violations (late reporting) because of EPA reporting tool issues or availability.

Response: We agree with commenter that we mischaracterized the proposed addition of requirements to submit data electronically in the proposed rule. The proposed electronic reporting provisions are not technical corrections but are amendments to the rule on which we solicited comments. Commenters raised concerns about the proposed requirements relevant to the effects of those provisions and we have developed responses to those comments as summarized below.

We agree with commenters that the template and the process for transmitting the quarterly reports of the type required by this rule are not yet available for review at the time of the proposal, let alone for implementing the regulatory requirements. In response to this comment, we have changed the rule to clarify that implementation of the requirement to electronic report quarterly reports will commence only when the electronic reporting tools (e.g., data submittal templates) and the data submission process are operative. (Note: Because the reporting template and data submission process for stack test reports are completed and operational, the requirement to submit stack test reports electronically will be effective on the compliance date).

We also believe that the templates and data submission process to be used for submitting the quarterly reports are similar to other on line electronic reporting systems with which commenters are very likely familiar. We will continue to communicate to stakeholders information about the structure of the data templates and data flow but we also believe that the submissions of compliance data through CEDRI will present no new or extraordinary data submittal skills over those required for other online reporting programs such as the Toxic Release Inventory Tier II forms since 2002 (<http://www.epa.gov/tri/tridata/index.html>) and the Greenhouse Gas Reporting Program (<http://www.epa.gov/climatechange/emissions/ghgrulemaking.html>). We will make known the availability of the electronic reporting tools and data submission process to be used to comply with the rule through multiple venues (e.g., the EPA's industrial boiler website,

<http://www.epa.gov/ttn/atw/boiler/boilerpg.html>, and the Technology Transfer Network CHIEF website, <http://www.epa.gov/ttn/chief/>). To inform affected sources of the concept of the reporting templates for the quarterly reports, we will also prepare and submit to the docket screenshots of a proposed template to accompany these responses to comments.

The EPA does not require the submission of all monitoring data as suggested by the commenters. Rather, the proposed rule only requires the submission of 30 day rolling averages. The EPA believes it is important to require the submissions of the 30 day rolling average data in the quarterly reports because these data serve multiple useful purposes and are important in:

Ensuring continued compliance performance of process and control device operations and providing sources with data to support compliance certifications,

Providing the sources and the agency with data representing variability of control measures for support of future (e.g., 8 year) regulatory reviews and updates, and

Identifying the best performing units and control approaches making more manageable and less burdensome future information data collection projects.

Accordingly, the final rule will stipulate that sources will submit hard copies of the compliance monitoring reports to the Administrator until the electronic reporting tools are in place. There will be no consequence relative to compliance should the electronic reporting tools not yet be ready when sources are required to report monitoring data. We believe that once the electronic data reporting tools are in use, sources will experience a reduced reporting and record keeping burden. Once sources submit data electronically, there will no need to store on site hard copies of reports and monitoring records that have been submitted electronically to WebFIRE. We agree with commenters that there are some other measures we can take to reduce reporting burden. For example, the final rule reduces reporting frequency to semiannually from the quarterly schedule in the proposal. We will make more clear in the final rule that the only data to be reported will be the 30-day averages required by the rule (e.g., ≤ 180 values for 30-operating day averaging periods per semiannual reporting period).

Commenter Name: Susan J. Miller

Commenter Affiliation: Brick Industry Association (BIA)

Document Control Number: EPA-HQ-OAR-2002-0058-3530-A1

Comment Excerpt Number: 5

Comment: EPA should not require quarterly reporting of data that is based on a system that does not exist and that have little likelihood of being used. EPA has included a new requirement in the December 2011 proposed Boiler MACT that will be excessively burdensome to industry. This requirement is not justified, and is not discussed in the preamble. New section 63.7550 (j) states:

“Within 60 days after the reporting periods ending on March 31, June 30, September 30, and December 31, you must transmit quarterly reports to EPA’s WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA’s Central Data Exchange (CDX) (www.epa.gov/cdx). For each reporting period, the quarterly reports must include all of the calculated 30 day rolling average

values based on the daily CEMS (CO and Hg) and CPMS (PM CPMS output, scrubber pH, scrubber liquid flow rate, scrubber pressure drop) data.”

There is no reason for EPA to require the submittal of all of a facility’s monitoring data. EPA has provided no justification for this new requirement. Facilities will provide certifications on their semi-annual compliance reports that they have performed the required monitoring and will provide information on any deviations from monitoring requirements or established parameter ranges. Additional parametric monitoring reports provide no useful purpose, environmental or otherwise, to anyone and are an additional administrative burden on operating facilities. EPA has already increased reporting burden by requiring all test data to be submitted electronically through the ERT, which continues to be revised and updated due to various flaws. We expect that this CEDRI interface would suffer from the same issues and may not even be available when facilities must submit their first of these quarterly reports. EPA has not yet built this interface, so industry has had no opportunity to provide comment on its usability or the burden it will impose. This addition to the rule was incorrectly characterized as a technical correction in Table 3 of the Preamble. The public has had no opportunity to evaluate the compatibility of existing data acquisition systems with this new EPA system. It is unreasonable to put sources at risk of violations (late reporting) because of EPA reporting tool issues or availability.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 139.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 150

Comment: QUARTERLY REPORTING OF ALL PARAMETER MONITORING DATA

EPA has included a new requirement in the Reconsideration Proposal that will be excessively burdensome to industry. This requirement is not discussed in the preamble and is not justified.

EPA has not yet built this interface, so industry has had no opportunity to provide comment on its usability or the burden it will impose. This addition to the rule was incorrectly characterized as a technical correction in Table 3 of the preamble.

More importantly, the regulated community has had no opportunity to evaluate the compatibility of existing data acquisition systems with this new EPA system. There is no reason for EPA to require the submittal of all of a facility’s monitoring data. EPA has provided no justification for this new requirement. Facilities will provide certifications on their semi-annual compliance reports that they have performed the required monitoring and will provide information on any deviations from monitoring requirements or established parameter ranges.

Additional parametric monitoring reports provide no useful purpose, environmental or otherwise, to anyone and are an additional administrative burden on operating facilities. EPA has already increased reporting burden by requiring all test data to be submitted electronically through the ERT, which continues to be revised and updated due to various flaws. ACC expects that this CEDRI interface would suffer from the same issues and may not even be available when facilities must submit their first of these quarterly reports. It is unreasonable to put sources at risk

of violations (late reporting) because of EPA reporting tool issues or availability. In order to simplify the rule requirements, EPA should not require submittal of these additional data at this time, and instead should keep this as a recordkeeping requirement against which any deviations will be reported under a site's Title V Operating Permit.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 139.

Commenter Name: Russell A. Wozniak

Commenter Affiliation: The Dow Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3449-A1

Comment Excerpt Number: 28

Comment: EPA should delete the proposed 40 CFR 63.7550(j) regarding the reporting of quarterly data to EPA's web-fire system.

Section 63.7550(j) of EPA's proposed rule requires that the owner/operator transmit quarterly reports to EPA's Web FIRE database that include all of the calculated 30 day rolling average values based on the daily CEMS (CO and Hg) and CPMS (PM CPMS output, scrubber pH, scrubber liquid flowrate, scrubber pressure drop) data.

EPA has explained the subject change as a technical correction to the rule. However, this type of reporting requirement creates a new applicable requirement that a facility must implement and abide by, and is in our opinion more than a technical correction. We also question whether EPA needs this level of data transmission in order to conduct work such as improving emission factors and whether the agency has resources to review and evaluate all of these additional data for existing boilers and process heaters.

In order to simplify the rule requirements, EPA should not require submittal of these additional data at this time, and instead should keep this as a recordkeeping requirement against which any deviations will be reported under a site's Title V Operating Permit.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 139.

Commenter Name: Sarah Hedrick

Commenter Affiliation: Verso Paper Corp.

Document Control Number: EPA-HQ-OAR-2002-0058-3537-A2

Comment Excerpt Number: 6

Comment: Section 63.7550 (j) requires facilities to transmit quarterly reports to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) accessed through EPA's Central Data Exchange (CDX) (www.epa.gov/cdx). For each reporting period, the quarterly reports must include all of the calculated 30 day rolling average values based on the daily CEMS (CO and Hg) and CPMS (PM CPMS output, scrubber pH, scrubber liquid flow rate, scrubber pressure drop) data. Inputting data into WebFIRE is not an easy and efficient method of data submittal for the regulated community. Data acquisition and reporting systems designed to collect, format, and upload data into EPA's electronic collection system are costly and extremely time consuming. Yet EPA has not described any meaningful purpose for

collecting all these data. Each boiler and control equipment configuration is unique; the data will not be comparable between boilers. Since EPA has proposed this new requirement with no justification, the requirement is unreasonable and unnecessary.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 139.

Commenter Name: Traylor Champion

Commenter Affiliation: Georgia-Pacific LLC (GP)

Document Control Number: EPA-HQ-OAR-2002-0058-3465-A1

Comment Excerpt Number: 29

Comment: The new and unprecedented proposal to require quarterly reporting of not only deviations but all data for all monitoring parameters is extremely burdensome and time consuming. And, it is contrary to all prior reporting framework in the CAA and Title V permitting, which requires periodic deviation reporting and rigorous annual compliance certification by each facility. EPA should eliminate the overly burdensome quarterly reporting of parametric monitoring data through EPA's CEDRI and CDX. This data is of little to no value to EPA and places an unnecessary burden on facilities.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 139.

Commenter Name: Randall D. Quintrell

Commenter Affiliation: Georgia Paper & Forest Products Association

Document Control Number: EPA-HQ-OAR-2002-0058-3451-A1

Comment Excerpt Number: 4

Comment: Compliance demonstration requirements are unwieldy, excessive and expensive, as briefly noted below.

The new and unprecedented proposal to require quarterly reporting of not only deviations but all data for all monitoring parameters is extremely burdensome and time consuming. And, it is contrary to all prior reporting framework in the CAA and Title V permitting, which requires periodic deviation reporting and rigorous annual compliance certification by each facility. The latter is more than adequate for this MACT as well.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 139.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 138

Comment: Quarterly reporting of daily operating parameter averages serves no purpose and, consistent with the requirements of Executive Orders 12866 and 13563, should not be finalized.

Proposed §63.7550(j) requires the following.

Within 60 days after the reporting periods ending on March 31, June 30, September 30, and December 31, you must transmit quarterly reports to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (www.epa.gov/cdx). For each reporting period, the quarterly reports must include all of the calculated 30 day rolling average values based on the daily CEMS (CO and Hg) and CPMS (PM CPMS output, scrubber pH, scrubber liquid flow rate, scrubber pressure drop) data.

We see no purpose for this requirement, since any daily average deviation will be reported in the normal periodic report and likely through Title V. Thus, it is a waste of facility and EPA time to gather the individual daily average data. If there is a concern about accurate deviation reporting, the daily averages will be available as records. Requiring such a large volume of information for no reason clearly violates Executive Orders 12866 and 13563.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 139.

Commenter Name: Robert Ellerhorst

Commenter Affiliation: Michigan State University

Document Control Number: EPA-HQ-OAR-2002-0058-3674-A2

Comment Excerpt Number: 10

Comment: U.S. EPA is proposing quarterly reporting requirements for emissions and operating parameters into the WebFIRE database. Under this reporting requirement, all sources would be obligated to report 30-day rolling average values based on the daily CEMS (CO and Hg) and CPMS (PM output, scrubber liquid flow and pressure drop) data within 60 days of the end of each quarter.

MSU believes that quarterly reporting to WebFIRE is unnecessary. As part of this requirement, data entry would be done through U.S. EPA's Central Data Exchange (CDX) and entered into the Compliance and Emissions Data Reporting Interface (CEDRI). Entry into CEDRI is a burdensome and time consuming process. Additionally, the amount of data that would be generated in these quarterly reports would exceed any amount of information that U.S. EPA would be of such a magnitude that it would in turn be burdensome for U.S. EPA to review. Furthermore, MSU will already be required to certify and submit semiannual compliance reports which will include emissions and operating information and an indication of deviations from emission limitations and monitor downtime.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 139.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 105

Comment: The Proposed rule requires sources, within 60 days after the reporting periods ending on March 31, June 30, September 30, and December 31, to transmit quarterly reports to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface

(CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (www.epa.gov/cdx). 40 CFR sec. 7550 (j)(proposed); 76 Fed. Reg. 32015. For each reporting period, the quarterly reports must include all of the calculated 30-day rolling average values based on the daily CEMS (CO and Hg) and CPMS (PM CPMS output, scrubber pH, scrubber liquid flow rate, scrubber pressure drop) data. 40 CFR §§63.7750(b) and 63.7550 (j).

EPA offers multiple unavailing reasons for imposing this never-before required submission of data. This quarterly requirement of data submission is not reasonable given the increased burden on sources and its lack of utility in ensuring compliance with the standards in this rule or improving environmental protection. EPA does not even attempt to assess the burden on sources, and the benefits it describes relate to the usefulness to EPA for future rulemaking efforts.

Among the reasons EPA propounds for this new reporting requirement is that by collecting performance test data now, the agency may not need to issue as many or as substantial CAA Section 114 information requests to obtain this data in the future. 75 Fed. Reg. 32,016. By mandating the perpetual submission of vast amounts of data to EPA, EPA subverts the intent of Congress in the Paperwork Reduction Act (PRA), which requires EPA and other agencies to obtain advance approval from the Office of Management and Budget (OMB) before imposing information production burdens on regulated sources. This information collection request approval process ensures that the burdens on regulated sources are assessed in advance and minimized whenever possible. EPA cannot avoid this requirement by requiring the piecemeal submission of "test data already collected for other purposes" on a perpetual basis.

Before mandating such a requirement, EPA must assess the additional burden that EPA thereby shifts to sources. Sources already must submit in many cases multiple MACT semi-annual compliance reports . With each report, a corporate officer or designee must certify the authenticity and accuracy of the submission. There is no rational need for sources to undertake another time-consuming reporting procedure, four times per year, and assume the additional substantial compliance risk that comes with this new requirement. EPA does not even attempt to assess the substantial additional burden of this requirement. Instead, with absolutely no record support, EPA claims that imposing this requirement will help EPA develop future regulations and thereby "save industry, State/local/Tribal agencies, and EPA time and money and work. . ." 76 Fed. Reg. 32016.

EPA describes as "easy" the use of its electronic reporting tool (ERT) and enhanced data management tools. 76 Fed. Reg. 32016. Yet data submission via the ERT will take a substantial amount of time and requires that multiple judgments be made by personnel entering and editing the data, and will require review and clearance by officers who are ultimately responsible for its accuracy. The aggregated number of labor hours across all the thousands of covered sources is absent from the record and would not be justified by EPA's rationales.

Response: Despite comments presented by the commenter, the EPA continues to believe it is important to require the submissions of the 30-day rolling average data in the semi-annual reports because these data serve multiple useful purposes and are important in: Ensuring continued compliance performance of process and control device operations and providing sources with data to support compliance certifications, providing the sources and the agency with data representing variability of control measures for support of future (e.g., 8 year) regulatory

reviews and updates, and identifying the best performing units and control approaches making more manageable and less burdensome future information data collection projects.

The Information Collection Requests, referred to by the commenter, for each rulemaking are updated every three years. Because the compliance date is 3 years from the publication of the rule, the EPA did not assess the burden of the reporting of the 30-day rolling average in this rulemaking. When the next ICR is due, the EPA plans to include the costs of the reporting of the requirements of section 63.7550(j). However, the EPA believes the commenter is correct in stating that semi-annual reporting of the 30-day rolling averages is burdensome. Thus, the EPA is revising the final rule to add this reporting requirement to the semi-annual compliance report, thus cutting this reporting burden by fifty percent .

The commenter states the Electronic Reporting Tool (ERT) will require “data submissions (that) will take a substantial amount of time and requires that multiple judgments be made by personnel entering and editing the data, and will require review and clearance by officers who are ultimately responsible for its accuracy.” Because the ERT has been in use for several years and for several ICRs, the EPA believes that most users have figured out the ERT in a reasonable amount of time. The commenter states that the ERT will require review and clearance by officers who are responsible for the accuracy (of the report). This is not a change from any routine reporting of performance test reports in any other NESHAP and has been a standard requirement in most EPA rules for many years. All performance test reports reported to EPA or the delegated State, Local, or Tribal Air Pollution Control Agency must be reviewed and signed by a “responsible official” that verifies the truth and accuracy of the report. Thus, the EPA disagrees that there is no rationale for the review and clearance by responsible officials and will not change the ERT electronic reporting requirements at this time..

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 106

Comment: EPA should assess thoroughly the volume of data it will receive each quarter vis-à-vis the functionality and dependability of its computer server. The tremendous volumes of electronic data that EPA will receive on the same day, four times per year, has not been quantified, nor has EPA apparently thought out how much of its computer server this will consume, the cost of the data management and storage, and potential risk to system stability.

In addition, to make use of this data, EPA staff must be prepared to sort through the volumes of information, ensuring the data has been properly quality assured in order to make the submissions useful to the Agency. The information collection and quality assurance associated with development of the Boiler MACT itself is an excellent example of the effort required to ensure reliable data goes into a database. The alternative to manually quality assuring data is to develop data checking software. This has been done in EPA’s Part 75 reporting program, but the effort on the part of sources to ensure data is uploaded in an acceptable format with the monitoring associated plans is costly and an unnecessary burden on sources. One CIBO member having four units in the NOx Budget Trading program spends \$25,000/year just to support the data QA and submission requirement of this Part 75 program.

Response: The EPA appreciates the comment regarding the volume of data expected from the electronic reporting requirements. The EPA is designing and choosing data storage media to adequately store the projected data and reports expected in this rulemaking. The EPA believes that the electronic reporting of these data will take up much less space than the paper copies that now reside in filing cabinets. The EPA agrees that quality assurance of the data is important, but wants to stress that the data will be quality assured when they are used. The EPA will store the data and reports received in the form they are received; these data and reports are enforceable documents and will be treated as such.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 107

Comment: By imposing this data submission requirement on sources that have a State regulator, EPA illegally supersedes the authority of the States. Once a State has adopted the boiler MACT into its SIP, sources have no ongoing data submission requirements to EPA, and EPA does not thereafter oversee their compliance with the standards. To impose this requirement on sources in States with delegated programs defeats the structure of the Clean Air Act and makes sources responsible not only to the State regulator but also to EPA in a manner not contemplated by the Act.

Response: The EPA disagrees with the commenter regarding EPA illegally superseding the authority of State, Local, and Tribal Air Pollution Control Agency's (S/L/Ts) to implement and enforce this regulation. Section 112(l) of the Clean Air Act Amendments of 1990 speaks and allows the delegation of authorities to implement and enforce section 112 provisions. Section 112(l)(7) states "[n]othing in this subsection shall prohibit the Administrator from enforcing any applicable emission standard or requirement under this section" In other words, the EPA always retains the right to enforce whether a subpart has been delegated to an S/L/T or not and is required by Section 112(l) to provide oversight of S/L/T programs.

Commenter Name: Pat Dennis

Commenter Affiliation: Archer Daniels Midland Company

Document Control Number: EPA-HQ-OAR-2002-0058-3670-A2

Comment Excerpt Number: 17

Comment: The Proposed rule requires sources to transmit quarterly reports to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX). This quarterly requirement of data submission is not reasonable given the increased burden on sources and its lack of utility in ensuring compliance with the standards in this rule or improving environmental protection. EPA does not even attempt to assess the burden on sources, and the benefits it describes relate to the usefulness to EPA for future rulemaking efforts.

EPA describes as "easy" the use of its electronic reporting tool (ERT) and enhanced data management tools. Yet data submission via the ERT will take a substantial amount of time and requires that multiple judgments be made by personnel entering and editing the data, and will

require review and clearance by officers who are ultimately responsible for its accuracy. The aggregated number of labor hours across all the thousands of covered sources is absent from the record and would not be justified by EPA's rationales.

In addition to burden, EPA should also assess thoroughly the volume of data it will receive each quarter vis-a-vis the functionality and dependability of its computer server. The tremendous volumes of electronic data that EPA will receive on the same day, four times per year, has not been quantified, nor has EPA apparently thought out how much of its computer server this will consume, the cost of the data management and storage, and potential risk to system stability.

Once a State has adopted the boiler MACT into its SIP, sources have no ongoing data submission requirements to EPA, and EPA does not thereafter oversee their compliance with the standards. The state agencies are largely severely pressed for human and financial resources at present. This massive data submission will potentially swamp state resources and increase program costs unnecessarily.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 139 for accepting quarterly data through the WebFIRE database. See the response to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 106 for the volume of data handled by EPA. See response to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 107 for the impact on state resources.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 108

Comment: Finally, the rule should make clear that sources in delegated States should not submit this high-volume data (parametric monitoring data) to States, which are not likely to want to gather and store the data.

Response: The EPA agrees with the commenter that the data summaries required in section 63.7550(j) should only be submitted to the EPA's WebFIRE database and not to State, Local, or Tribal Air Pollution Control Agencies (S/L/Ts). The EPA is clarifying this requirement in the final rule. However, these data can be accessed and used by S/L/Ts in WebFIRE.

Commenter Name: Vickie Woods

Commenter Affiliation: Division of Air Quality, North Carolina Department of Environment and Natural Resources (NCDENR)

Document Control Number: EPA-HQ-OAR-2002-0058-3663-A2

Comment Excerpt Number: 2

Comment: EPA is proposing additional quarterly reporting requirements beyond semi-annual reporting of various performance related issues. In addition to recent requirements for many performance tests and CEM RATA related tests to be reported to EPA via the Electronic Reporting Tool (ERT) through the Central Data Exchange (CDX), the EPA has proposed that various data streams (CEM data, various CPMS and operating data) be reported to EPA on a quarterly basis.^[11]

NC DAQ Comment

Although EPA did not discuss this proposal in the preamble, they did request comment on this issue. Given there is no clarification for this requirement in the preamble, many questions come up about its use, access, and limitations. The NC DAQ understands the desire for better and more contemporaneous data for EPA's standard setting processes and emission factor development and has previously commented on this issue. However, this electronic reporting of various data raises several concerns for the NC DAQ.

First, no electronic data tool appears to be ready for review for the data that EPA is requiring to be submitted by affected residual oil and coal-fired units. The proposed changes require the data to be reduced to a series of arithmetic averages to produce hourly, daily and 30-day average values, but the proposed regulation is unclear about what data must be submitted as part of this quarterly reporting.

Second and more broadly, the proposed regulations require this data, as well as performance tests and CEM performance testing (via the ERT, if the test procedures are included in the ERT tool) to be submitted directly to EPA. It is silent on how and whether state agencies would access the data. Unless these tests and data showed deviation from a standard, only summaries of these performance tests and data would be included as part of the semi-annual report submitted to NC DAQ. As the delegated authority, this raises questions about accessibility for NC DAQ to the data and required testing in this proposed rule, and how that information might flow from the affected facility to NC DAQ.

[Footnote 1: Federal Register, Vol. 76, No. 247, December 23, 2011, page 80649-50.]

Response: The EPA disagrees with the comment that the proposed regulation is unclear. Section 63.7550(j) states “[f]or each reporting period, the semi-annual reports must include all of the calculated 30 day rolling average values based on the daily CEMS (CO and Hg) and CPMS (PM CPMS output, scrubber, pH, scrubber liquid flow rate, scrubber pressure drop) data.” The EPA believes that this paragraph clearly requires the facility to calculate a 30-day rolling average for each CEMS and CPMS daily and provide that value semi-annually. Thus, a semi-annual submittal for this requirement will be about 120 daily values for each CEMS or CPMS. The EPA does plan to develop a reporting template or tool for submittal of these data, but we expect it to be simple and straightforward because there are not any additional data needed or required for this report.

Regarding access to the data summary, performance test, excess emissions, and summary data required to be submitted electronically to the EPA’s WebFIRE database, the EPA is designing WebFIRE so that the State, Local, and Tribal Air Pollution Control Agency (S/L/Ts) and all users will have full access to these data in WebFIRE at all times. This proposal requires performance tests (section 63.7550(h)), data summaries (section 63.7550(j)), and relative accuracy test audit data (section 63.7550(i)) to be submitted electronically to the EPA’s WebFIRE database. The EPA had also intended to include the compliance reports, required in section 63.7550(b), to be submitted electronically to the EPA’s WebFIRE database. This will be clarified in the promulgation of this rulemaking. The EPA had also intended to add the sentence at the end of the paragraph in section 63.7550(h), “[a]t the discretion of the delegated authority, you must also submit these reports, including the confidential business information, to the

Administrator in the format specified by the Administrator” to sections 63.7550(i) and (j). This sentence allows the S/L/Ts to receive copies of these reports if S/L/Ts choose and in the manner S/L/Ts choose. Thus, S/L/Ts can continue to receive these reports in written or electronic forms and can continue to access the reports in the manner the S/L/Ts choose. However, the EPA is hopeful that S/L/Ts will choose to begin using the electronic reports, when possible, for review and compliance purposes..

Commenter Name: David A. Buff, Golder Associates Inc.

Commenter Affiliation: Florida Sugar Industry (FSI)

Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1

Comment Excerpt Number: 60

Comment: Section 63.7550(j) of the March 2011 Final Boiler MACT Rule contained a new requirement -- all parametric monitoring data (i.e., scrubber pH, scrubber liquid flow rate, scrubber pressure drop, ESP power, etc.) must be reported to EPA on a quarterly basis. The quarterly report also must contain the calculated 30-day rolling averages based on the daily average data. FSI respectfully requests EPA to revise these reporting requirements. The FSI believes the data should be reported in the same manner as the Compliance Assurance Monitoring (CAM) data that are already reported under Title V operating permits. Under EPA’s Title V program, only deviations from the parametric ranges must be reported, and the reports are submitted on a semi-annual basis. It would be appropriate to make the reporting requirements for these two federal programs consistent. Making the reporting requirements consistent also would reduce the significant reporting burden that will be created if the regulated community must submit all of the parametric monitoring data for each boiler.

Response: The EPA intends to use the data summaries required in section 63.7550(j) for regulation development and rule effectiveness studies. The EPA believes that requiring the daily average for a 30-day rolling average will provide a more representative record of how well units and control devices are working which will enable the EPA to better develop and/or assess federal regulations. Further, the EPA believes it is important to require the submissions of the 30-day rolling average data in the semi-annual reports because these data serve multiple useful purposes and are important in:

Ensuring continued compliance performance of process and control device operations and providing sources with data to support compliance certifications,

Providing the sources and the agency with data representing variability of control measures for support of future (e.g., 8 year) regulatory reviews and updates, and

Identifying the best performing units and control approaches making more manageable and less burdensome future information data collection projects.

Accordingly, the final rule will stipulate that sources will submit the compliance monitoring reports to the Administrator electronically; although, the requirement will be contingent upon whether the EPA has the electronic reporting tools operational and in place. There will be no consequence relative to compliance should the electronic reporting tools not yet be ready when sources are required to report monitoring data. We believe that once the electronic data reporting tools are in use, sources will experience a reduced reporting and record keeping burden. Once

sources submit data electronically, there will no need to store on site hard copies of reports and monitoring records that have been submitted electronically to WebFIRE.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 141

Comment: Proposed §63.7550(j) requires quarterly periodic reports of operating parameter daily averages. Although daily averages are reviewed immediately to determine if a deviation has occurred, having to gather and tabulate this information quarterly adds unnecessary burden, since this information would normally be gathered and tabulated semi-annually for use in preparing the normal periodic reports. As we discuss in Comment A of this section, EPA has no use for this information since deviations are reported in the semi-annual report and thus, if it is not deleted, there is no reason to require submitting this data more frequently than semi-annually. Thus, we recommend the requirement for submitting all daily averages be deleted and if not deleted that it only be required as part of the semi-annual report.

Response: We have reduced the frequency of reporting to Webfire to semi-annually. We have clarified in the final rule that the only data to be reported will be the 30-day averages required by the rule. See the response to comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 139.

Commenter Name: M.L. Steele

Commenter Affiliation: CraftMaster Manufacturing, Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3814-A1

Comment Excerpt Number: 21

Comment: §63.75500) Submit *quarterly* reports to USEPA Webfire database. Where are quarterly reports specified? Per Table 9, reports are required no more frequently than semiannually.

Response: We have reduced the frequency of reporting to Webfire to semi-annually. See the response to comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 139.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 145

Comment: Reporting and recordkeeping requirements for secondary material fuels are unclear relative to gases and should be clarified.

The majority of BPH subject to this proposal are gas-fired. Gases are not secondary materials unless they are combusted along with a container. Since gaseous fuels are so prevalent and will

almost never be secondary materials we request gases be specifically excluded from the secondary materials recordkeeping and reporting requirements.

Proposed §63.7555(d)(2) requires records if you combust non-hazardous secondary materials. From the definition in §241.2 it is unclear relative to gaseous fuels used in refineries, what fuels are non-hazardous secondary materials and thus what fuels require such records. It would save considerable effort and confusion if this is clarified in §63.7555(d)(2) by specifically excluding all gases that are not combusted along with the container in which they are contained. If that general exclusion is not acceptable, we request that natural gas, refinery gas and other gas 1 fuels be specifically exempted.

Response: We disagree that §63.7555(d)(2) needs to be revised. 63.7555(d)(2) only requires that a source keep the documents that show how the secondary material is not a solid waste.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 147

Comment: Proposed §63.7555(d)(6) requires, if you are skipping stack tests, "annual records that document that your emissions in the previous stack test(s) were less than 75 percent of the applicable emission limit." Since there are not stack tests in this situation we do not understand what "annual records" are needed. It would seem only "a record" is needed. §63.7555(d)(6) should be clarified on this point.

Response: The EPA agrees with the commenter and has clarified §63.7555(d)(6) accordingly.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 148

Comment: Since there is no longer a hydrogen sulfide criterion for other gas 1, the requirement to keep records of the hydrogen sulfide content and calculations for other gas 1 gases in proposed §63.7555(g) should be deleted.

Response: The final rule does not include requirements to keep records for hydrogen sulfide content or calculations for other gas 1 gases in 63.7555(g).

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 149

Comment: As discussed relative to proposed §§63.7530(g) and 63.7540(c), "could" is an unreasonable criterion for requiring monthly records relative to the mercury limit for other gas 1 gases and the criterion should be "can reasonably be expected to". Thus, the use of the word "could" in proposed §63.7555(g) should be replaced with "can reasonably be expected to". Additionally, the reference to "§63.7545(g)" should be corrected to "§63.7530(g)".

Response: The EPA thanks the commenter for their input and has revised 63.7555(g) accordingly.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 150

Comment: Proposed §63.7555(h) applicability is unclear. §63.7555(h) should be revised as follows.

If you operate a unit ~~designed to burn natural gas, refinery gas, or other gas 1 fuel, or gases that is subject to this subpart in the gas 1 subcategory~~, and you use an alternative fuel other than natural gas, refinery gas, ~~or~~ other gas 1 fuel, or gaseous fuels subject to another subpart of this part or part 60, 61 or 65, you must keep records of the total hours per calendar year that alternative fuel is burned.

Response: The EPA has revised 40 CFR 63.7555(h) to clarify the subcategory and include other gaseous fuels subject to another subpart of this part or part 60, 61, or 65.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 37

Comment: The proposed definition of "unit designed to burn liquid subcategory" contains the allowance for testing, maintenance, or operator training twice. One of the duplicate phrases in the definition should be deleted.

Response: The EPA thanks the commenter for their input and has removed the redundant text from 40 CFR 63.7575 accordingly.

10Z. Other Rule Language Corrections

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 2

Comment: It is also critical that adequate time be allotted to crafting clear regulatory language for the final rules. As indicated by our many editorial comments on the major source proposal, much of the proposed language is unclear, inconsistent, and confusing. In some cases, it is not even consistent with the apparent intent indicated in the preamble or in other portions of the rule. Similarly, there are significant differences in rule language for the same requirement between the major source and area source rules.

Response: The EPA thanks the commenter for their support.

Testing and Monitoring

11A. Minimum Data Availability for CEMS/CPMS

Commenter Name: Lee Zeugin and Lauren Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1

Comment Excerpt Number: 32

Comment: On reconsideration, EPA defends its final rule as reasonable. EPA explains its view that maintenance performed as normal scheduled quality control events under a site-specific quality control program required under § 63.8(d)(2)(iii) would be exceptions to the data collection requirements. 76 Fed. Reg. at 80610/2. EPA also proposes to add a reference to “scheduled CMS maintenance as defined in your site-specific monitoring plan” to § 63.7535(b). UARG appreciates and supports EPA’s explanation and proposed rule revision regarding maintenance periods. For consistency, UARG requests that EPA add similar language regarding maintenance to § 63.7535(d).

Unfortunately, EPA does not discuss or explain its position with respect to out-of-control periods. 76 Fed. Reg. at 80610/2. Moreover, EPA has not proposed to remove from § 63.7525(c)(6) language requiring identification of COMS out-of-control periods as deviations, and has proposed adding a similar provision regarding PM CPMS. Proposed § 63.7525(d)(3). EPA also has proposed to remove out-of-control periods from the exceptions to what constitute a deviation under § 63.7535(d). Accordingly, the rule is still internally inconsistent with respect to out-of-control periods. UARG requests that EPA remove the references to out-of-control periods from §§ 63.7525(c)(6) and (d)(3), and that EPA not finalize its proposed removal of out-of-control periods from the list of exceptions to monitoring deviations in § 63.7525(d). UARG notes that EPA included out-of-control periods in such a list in § 63.10020(d) of the recently promulgated EGU MACT rule. 77 Fed. Reg. 9304, 9479 (Feb. 16, 2012).

Response: The EPA thanks the commenter for their support on the explanation regarding maintenance periods. In the final rule, we have revised §63.7535(d) to be consistent with §63.7535(b).

Additionally, we have revised the language in the final rule to be more consistent with the language in the EGU MACT rule.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 110

Comment: It is unprecedented to make every Continuous Monitoring System (CMS) out-of-control occurrence a deviation. As is typical of other rules, a data availability criterion should be established instead. Following rule quality assurance and maintenance requirements and normal instrument drift should not result in rule or Title V deviations, much less a multitude of deviations. Proposed §63.7525(c)(6) and (d)(3) should not be finalized. Proposed §63.7525(c)(6) specifies that any 6-minute period for which a Continuous Opacity Monitoring System (COMS) is out-of-control and data are not available for a required calculation is a deviation. Since the criteria for being out-of-control are specified either from daily to annual, each such event creates 240 to 87,600 deviations. Similarly, proposed §63.7525(d)(3) specifies that any 15-minute period for which a Continuous Parameter Monitoring System (CPMS) is out-of-control and data are not available constitutes a deviation. Since the criterion for out-of-control is a daily check, each out-of-control occurrence results in 96 deviations. Since many quality assurance and maintenance activities take more than 6 minutes or 15 minutes, many required quality assurance and maintenance activities will be deviations.

Making these occurrences deviations, and presumably violations, discourages obtaining quality data because of the potential penalty for doing so and because you are punished for undertaking preventive steps. Since it is impossible to not have a deviation, and very good performance is not recognized, there is no incentive to do more than the minimum the rule requires. Furthermore, these requirements contradict proposed §63.7535 and violate the requirements in the rule to develop and follow a site specific monitoring plan that addresses quality assurance and monitor maintenance and to perform certain performance evaluations (e.g., as required in §63.7525(e)(4) for flow monitors). How can it be a deviation to do activities that are required under other portions of the rule? Allowed monitor data outages are appropriately addressed in proposed §63.7535 and thus §63.7525(c)(6) and (d)(3) should not be finalized.

Response: We believe that making these occurrences deviations encourages, rather than discourages, obtaining quality data. As all periods where data is not collected is a deviation, we believe that this will encourage people to collect as much data as possible, instead of trying to meet an arbitrary data availability limit. The final rule allows for periods of monitoring deviations in order to perform scheduled CMS maintenance and quality assurance activities, as described in §63.7535(b). Additionally, §63.7535(d) has been revised to be consistent with §63.7535(b).

See the response to comment EPA-HQ-OAR-2002-0058-3500-A1, excerpt 32 for discussion of out-of-control periods.

See the response to comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 110 for further discussion of minimum data availability.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 110

Comment: EPA should add minimum monitoring system data availability requirements. There will be times, even with a well maintained continuous monitoring system, when the system will be out of operation. Lengthening averaging periods to 30 days is not adequate to address this issue.⁴⁶ Even the final CISWI rule provided minimum data availability requirements for PM CEMS of 85 percent of the hours per day, 90 percent of the hours per calendar quarter, and 95 percent of the hours per calendar year that the affected facility is operated.⁴⁷ The final Large Municipal Waste Combustor rule also has data availability requirements: valid continuous monitoring system hourly averages shall be obtained at least 90 percent of the operating hours per calendar quarter and 95 percent of the operating hours per calendar year.⁴⁸ The Petroleum Refinery MACT, Subpart UUU, states that each continuous parameter monitoring system must have valid hourly average data from at least 75 percent of the hours during which the process operated.⁴⁹ EPA is not persuasive in its response that the need for minimum data availability provisions such as those in NSPS Subpart Da no longer exists due to EPA's better understanding of the need for continuous data collection and the dramatic improvement in CEMS data availability (citing Acid Rain Program). SO₂ CEMS used under the Acid Rain Program would differ starkly from some of the other CEMS (Hg, HCl, PM) that might be used under the Boiler MACT. SO₂ CEMS are a mature technology in widespread use, but even mature CEMS technologies such as SO₂, NO_x, and CO should be provided some reasonable amount of downtime. The Acid Rain rules recognize that NO_x and SO₂ monitors have downtime by including missing data procedures in Appendix C to 40 CFR 75. All equipment will malfunction at some point in time, and EPA should acknowledge this fact by providing a minimum data availability requirement in the Boiler MACT for continuous monitoring systems.

[Footnote 46: EPA responded that, "[r]egarding comments on PM CEMS, we have modified the language from the proposed 24-hour block to a 30-day rolling average. We disagree with the commenter about applying the data availability used in Da to the PM CEMS data collection. The Agency has developed a better understanding of the need for continuous data collection since Da was published and the equipment and software have dramatically improved as shown by the acid rain program CEMS data availability success. The monitoring system must operate at all times the process is operating." Response to Comments, EPAHQ-OAR-2002-0058-2908.1, excerpt number 31.]

[Footnote 47: See 40 CFR 60.2730(n)(14).]

[Footnote 48: See 40 CFR 60.58b(c)(10)(viii).]

[Footnote 49: See 40 CFR 63.1572(c)(3).]

Response: We have not included any specific minimum data availability requirement for CEMS or other monitoring in this final rule nor do we provide a specific tool for data substitution. We believe that there are other provisions in the final rule to provide incentives to conduct monitoring in a manner consistent with good air pollution control practices and to provide data

sufficient to demonstrate compliance with a relatively long-term emissions rate limit. Data quality certainty associated with any calculated value decreases with the collection of fewer data such as would occur with extended periods of monitoring system downtime. We believe that it is necessary and critical to compliance with the regulation that a source uses all measured data collected during an averaging period to assess compliance regardless of any periods of missing data. Sources should not disqualify any data otherwise meeting required data quality requirements simply because there were data missing for other hours or days of the averaging period. Instead of a minimum data availability threshold that would invalidate data collected for some averaging periods because one did not collect enough data to validate data collected, sources must report as deviations to the rule failures to collect data during required periods and that are not covered by exceptions allowed in the final rule. We believe that enforcement authorities have the discretion to determine the severity of the missing data and what action must be taken in response to the deviation. Should the source or the enforcement authority be concerned about the representativeness of data such as during periods of missing data, either may consider collecting information through other means (e.g., supplemental emissions testing) to fill data gaps not only because such gaps are deviations from the rule but such gaps can lead to uncertainty about compliance status.

We further believe that the final rule provides sufficient means to ensure CMS performance and ongoing compliance without specifying an arbitrary numerical minimum data availability. We believe that specifying that failure to collect required or otherwise excepted data is a deviation from the rule will provide the necessary incentive to collect data sufficient to demonstrate compliance with the limits in the final rule.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 55

Comment: *MINIMUM DATA AVAILABILITY*

ACC requests EPA reconsider its response to the requests to add minimum CEMS data availability requirements. At least two commenters, Dominion and the Industrial Minerals Association, noted that the requirement to have valid CEMS data for all operating hours is not realistic.¹⁸ There will be times, even with a well maintained CEMS, when the system will be out of operation. EPA's response that, somehow, lengthening the averaging period for PM CEMS from 24 hours to 30 days addresses these comments is inadequate.¹⁹ ACC notes that the final Commercial/Industrial Solid Waste Incinerator (CISWI) rule provides minimum data availability requirements for PM CEMS. *See* 40 C.F.R. 60.2730(n)(14). EPA's response that the need for minimum data availability provisions such as those in NSPS Subpart Da no longer exists due to EPA's better understanding of the need for continuous data collection and the dramatic improvement in CEMS data availability (citing Acid Rain Program) is also not persuasive. SO₂ CEMS used under the Acid Rain Program differ starkly from some of the other CEMS (Hg, HCl, PM) discussed above. SO₂ CEMS are a mature technology in widespread use. Even mature CEMS technology such as SO₂, NO_x, and CO should be provided some reasonable amount of downtime. Therefore, ACC respectfully requests that EPA reconsider its decision to not include

minimum data availability requirements, and to propose for comment a reasonable allowance for equipment downtime in 40 C.F.R. 63.7525(a)(6).

[Footnote 18: See Response to Comments, EPA-HQ-OAR-2002-0058-2908.1, excerpt number 31; EPA-HQ-OAR-2002-0058-2740.2, excerpt number 14.]

[Footnote 19: EPA responded that, “[r]egarding comments on PM CEMS, we have modified the language from the proposed 24-hour block to a 30-day rolling average. We disagree with the commenter about applying the data availability used in Da to the PM CEMS data collection. The Agency has developed a better understanding of the need for continuous data collection since Da was published and the equipment and software have dramatically improved as shown by the acid rain program CEMS data availability success. The monitoring system must operate at all time the process is operating.”] [Response to Comments, EPA-HQ-OAR-2002-0058-2908.1, excerpt number 31.]

Response: See the response to comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 110.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 118

Comment: Proposed §63.7535 should be the basis for rule data handling. However, it should clarify how to handle data collected during startup and shutdown periods.

Proposed §63.7535 is entitled “Is there a minimum amount of monitoring data I must obtain?” While this section lays out reasonable requirements for what data should be included in compliance demonstrations and what data should not be included, it never really answers the question in the title. Furthermore, there are conflicts between this section and requirements elsewhere in the proposal. We have tried to identify as many of those conflicts as possible in these comments and recommend those places in the proposal that conflict with §63.7535 should be deleted or revised.

Additionally, this section essentially requires all valid data to be used to “assess compliance.” We believe, it must be specifically clarified that in assessing compliance with numerical emission limits data collected during periods of startup and shutdown are excluded from emission averages as provided in §63.7500(e).

Response: §63.7525(d)(1) states: "The continuous parameter monitoring system must complete a minimum of one cycle of operation every 15-minutes. You must have a minimum of four successive cycles of operation, one representing each of the four 15-minute periods in an hour, to have a valid hour of data." The definitions of "10-day rolling average" and "30-day rolling average" have been revised and include the phrase "hours of valid operating data" and both definitions include "Valid data excludes hours during startup and shutdown, data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is

out of control, or while conducting required monitoring system quality assurance or quality control activities, and periods when this unit is not operating."

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 133

Comment: Proposed §63.7525(d)(1) specifies that you must have four successive cycles of operation to have a valid hour of data for a continuous parameter monitoring system. Since most such systems collect many data points per second, this seems to say a fraction of a second's data provides a valid hour of data. We assume the actual intent was to require some data from each 15 minute period and, if so, this wording needs to be revised. Furthermore, it is common practice for a valid hour of data to be any hour where at least two 15 minute periods are represented and we recommend that be incorporated into the rule, so all the hours during which brief quality assurance checks are performed (e.g., daily drift check of the PM CPMS required by the rule for some BPH) won't be lost due to one 15 minute period missing data. We recommend the language from proposed §63.7525(l)(6) be used as a model for a revised §63.7525(d)(1).

Response: We have made revisions to §63.7525(d)(1) to indicate that our intent is for the source to collect at least one data point for each of the 15-minute periods in an hour.

Commenter Name: Vickie Woods

Commenter Affiliation: Division of Air Quality, North Carolina Department of Environment and Natural Resources (NCDENR)

Document Control Number: EPA-HQ-OAR-2002-0058-3663-A2

Comment Excerpt Number: 12

Comment: Minimum Data Availability. A continuous monitoring system (CMS) must undergo periodic system inspections, preventive maintenance, and parts replacements to continue good operation. It is clear these events are among normal scheduled quality control events included in the site-specific quality control program required under 63.8(d)(2)(iii).

NC DAQ agrees with the clarification concerning the use of CMS and the site-specific plan to meet routine preventive maintenance on the CMS system. We concur that that this clarification is consistent with good operating practices for CMS systems.

Response: The EPA thanks the commenter for their support.

11B01. Oxygen Monitors: Appropriateness and Location of

Commenter Name: Russell A. Wozniak

Commenter Affiliation: The Dow Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3449-A1

Comment Excerpt Number: 15

Comment: Section 63.7525 (a) provides the option of using an oxygen analyzer or CO CEMS to maintain compliance with CO requirements per Table 4. Dow supports providing the oxygen analyzer option.

Response: The EPA thanks the commenter for their support.

Commenter Name: David A. Buff, Golder Associates Inc.
Commenter Affiliation: Florida Sugar Industry (FSI)
Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1
Comment Excerpt Number: 10

Comment: The FSI supports EPA's decision to allow the use of an "oxygen analyzer system" (i.e., O₂ monitoring and/or oxygen trim system) as an alternative to a continuous emissions monitoring system ("CEMS") for CO. We support EPA's rationale for proposing alternatives to certifying O₂ monitors.

Response: The EPA thanks the commenter for their support.

Commenter Name: Paul Noe
Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.
Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1
Comment Excerpt Number: 100

Comment: EPA has proposed the use of O₂ trim systems to optimize air to fuel ratio, combustion efficiency, and to maintain compliance with CO emission levels demonstrated during the performance test. This was in response to concerns from petitioners about the inability to certify O₂ monitors according to applicable Performance Specifications if located at the boiler outlet (due to stratification at this location). We support EPA's rationale for proposing alternatives to certifying O₂ monitors.

Response: The EPA thanks the commenter for their support.

Commenter Name: Bart Sponsellar
Commenter Affiliation: Wisconsin Department of Natural Resources
Document Control Number: EPA-HQ-OAR-2002-0058-3527-A2
Comment Excerpt Number: 12

Comment: EPA is proposing to the use of "oxygen trim" systems to optimize air fuel ratios and optimize combustion in place of installing separate oxygen monitoring systems on the stack in order to meet parametric monitoring requirements for the carbon monoxide emission limitation. Many sources already have an oxygen trim system in place and EPA is determining that it is a better way to achieve good combustion versus only monitoring oxygen with no trim system.

The Department supports EPA's approach to using oxygen trim systems as a better means for parametric monitoring and ensuring good continuous combustion. Our support is based on a similar requirement in place here in Wisconsin since 2002 for certain sources operating in our ozone non-attainment area. The affected source categories subject to this good combustion

requirement include stoker boilers, glass furnaces, and lime kilns. Under this requirement, the sources must continually monitor both O₂ and CO flue gas concentrations and trim the system to optimize combustion and reduce NO_x emissions – basically minimize excess combustion air while ensuring complete combustion.

Response: The EPA thanks the commenter for their support.

Commenter Name: Vickie Woods

Commenter Affiliation: Division of Air Quality, North Carolina Department of Environment and Natural Resources (NCDENR)

Document Control Number: EPA-HQ-OAR-2002-0058-3663-A2

Comment Excerpt Number: 8

Comment: Oxygen. Proposing single O₂ analyzer located in combustion chamber with oxygen trim systems for continuous compliance without requiring CO and O₂ CEMS located in stack.

NC DAQ concurs with EPA's proposed approach on this issue.

Response: The EPA thanks the commenter for their support.

Commenter Name: Bill Lane

Commenter Affiliation: American Home Furnishings Alliance (AHFA)

Document Control Number: EPA-HQ-OAR-2002-0058-3676-A2

Comment Excerpt Number: 9

Comment: AHFA supports EPA's proposal to allow the use of oxygen trim systems for demonstration of compliance with CO emission standard. AHFA believes this provides a lower cost and more flexible option than the March 2011 final rule.

Response: The EPA thanks the commenter for their support.

Commenter Name: Kevin G. Desharnais, Attorney, Mayer Brown LLP

Commenter Affiliation: United States Sugar Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3496-A1

Comment Excerpt Number: 5

Comment: In the Final Rule, EPA added a new requirement that O₂ CEMS units be installed on the outlet of the boiler combustion chamber as a means of ensuring good combustion practices. This proposal was met with numerous technical objections. 76 Fed. Reg. at 80609. In its Reconsideration Proposal, EPA has removed the O₂ CEMS requirement and is instead proposing the use of an oxygen trim system as a means of optimizing air to fuel ratio and combustion efficiency. The proposal sets a "minimum" O₂ level, with compliance based on a 30-day rolling average. U.S. Sugar supports the use of an oxygen trim system as an appropriate means of ensuring good combustion practices.

Response: The EPA thanks the commenter for their support.

Commenter Name: Lorraine Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1
Comment Excerpt Number: 36

Comment: OXYGEN MONITORING

a. The Change from O2 CEMS to O2 Trim is Appropriate and Supportable

In the Final Boiler Rule, EPA included continuous oxygen (O₂) monitoring as the compliance method for sources with a CO limit, instead of mandating the use of CO continuous emissions monitoring system (CEMS). EPA now proposes to amend the O₂ monitoring requirements to allow for the use of continuous oxygen trim analyzer systems instead of oxygen CEMS. (76 Fed. Reg. 80609) EPA also proposes to remove the requirement that the oxygen monitor be located at the outlet of the boiler, so that it can be located either within the combustion zone or at the outlet as a flue gas oxygen monitor. ACC supports EPA's proposal to add flexibility and reduce the cost and burden of the continuous oxygen monitoring requirements, as these changes allow facilities to utilize existing oxygen trim systems rather than installing CEMS.

Response: The EPA thanks the commenter for their support.

Commenter Name: Paul Noe
Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.
Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1
Comment Excerpt Number: 37

Comment: Appropriate numerical limits must be paired with an appropriate testing period and methodology to constitute an achievable MACT limit where compliance can be ensured on a continuous basis. For some proposed limits EPA has accomplished this workable structure and for others they have not. For example, CO limits as a surrogate for organic HAP to assure good combustion practices, established as a 3-hour maximum load stack test requirement accompanied thereafter by maintenance of 30-day average oxygen levels (reflective of excess air) at or above levels measured during the performance test is a comprehensive standard for many boiler operators to meet that achieves both environmental objectives and operational needs. We support this testing and monitoring paradigm as an alternative in the rules for a wide range of operators.

Response: The EPA thanks the commenter for their support.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1
Comment Excerpt Number: 66

Comment: In the Final Boiler MACT Rule, EPA required continuous oxygen monitoring for boilers subject to CO numeric emission limits. 76 Fed. Reg. 15,671-73. (2011 Final Rule). EPA finalized this approach as an alternative to requiring the use of CO CEMS. While EPA maintained this approach in the 2012 Reconsidered Boiler MACT Rule, EPA did modify the rule

to provide more flexibility. EPA's oxygen monitoring approach and decision to increase flexibility is appropriate, however additional clarification is needed.

EPA concluded that, instead of requiring monitoring of oxygen levels in the stack, "a better way to ensure good combustion is by requiring the installation, calibration, monitoring and use of oxygen trim systems to optimize air to fuel ratio and combustion efficiency." 76 Fed. Reg. 80,609. (2012 Reconsidered Boiler MACT Rule). EPA reasoned that "the data from such devices is not only an appropriate control for efficient combustion and a less burdensome alternative to monitoring stack oxygen concentration but also is a better system for many types of units that experience significant load swings and operate with high levels of excess air." 76 Fed. Reg. 80,609. (2012 Reconsidered Boiler MACT Rule). As set forth in comments CIBO's Petition for Reconsideration of the Final Boiler MACT Rule, EPA's proposed oxygen monitoring requirements are appropriate and the EPA was justified in increasing the flexibility.

Response: The EPA thanks the commenter for their support.

Commenter Name: Douglas A. McWilliams

Commenter Affiliation: American Municipal Power

Document Control Number: EPA-HQ-OAR-2002-0058-3685-A2

Comment Excerpt Number: 38

Comment: AMP Supports Replacing the O₂ CEM Requirement with an O₂ Trim System Requirement

In the 2011 Boiler MACT rule, EPA imposed an O₂ CEM requirement on sources subject to CO limits that required sources to continuously monitor and maintain O₂ levels above the operating limit established during stack testing. An O₂ CEM measures oxygen concentrations in the stack gas. As many commenters noted, O₂ measurements in the stack gas are not a proper measure of good combustion. Furthermore, many existing boilers and process heaters already utilize flue gas oxygen analyzers for indication, alarm, and O₂ trim control, where the fuel/air ratio is automatically controlled for optimum combustion conditions. To the extent EPA retains CO emissions limits and/or operating limits, AMP supports the use of an O₂ trim analyzer in lieu of an O₂ CEM for purposes of demonstrating continuous compliance.

Response: The EPA thanks the commenter for their support.

Commenter Name: M.L. Steele

Commenter Affiliation: CraftMaster Manufacturing, Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3814-A1

Comment Excerpt Number: 12

Comment: Continuous monitoring of O₂ for CO Limit, §63.7525(a). We support EPA's decision to provide an alternative to allow existing CO GEM's to meet the monitoring requirements for CO emissions.

Response: The EPA thanks the commenter for their support.

Commenter Name: Russell A. Wozniak
Commenter Affiliation: The Dow Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3449-A1
Comment Excerpt Number: 17

Comment: Element 9.a. of Table 8 states that if using Oxygen content as the operating limit then continuous compliance is demonstrated by “continuously monitoring the oxygen content using an oxygen trim system according to § 63.7525(a).” The owner/operator may have multiple oxygen analyzers installed on the boiler or process heater. The oxygen analyzer used for demonstrating compliance should not be required to be the oxygen analyzer used in the oxygen trim system. The key element is that the oxygen analyzer located where oxygen was measured during the CO Performance Test be the same location used for demonstrating continuous compliance. Table 8(9)(a) should be revised as follows:

a. ~~Continuously monitor the oxygen content using an oxygen trim system according to § 63.7525(a) the same oxygen analyzer location as used in the performance test of Table 5(4)(b).~~

Response: The EPA disagrees with the commenter in that we allow for the use of an O₂ monitor or O₂ trim system to be used for compliance with the rule. The source operator may choose the system of their preference and select that path for compliance. The source operator may not change their monitoring scheme and switch to another analyzer or O₂ trim system without conducting another performance test to set the operating parameter correlation. If an aggregate average of several analyzers is used to meet compliance with this section of the rule, that aggregate average then represents a single O₂ monitoring system and changes to such a system (such as removing or adding monitors from the scheme) would require another performance test to set the operating parameter correlation.

Commenter Name: Dakota Gasification Company Great Plains Synfuels Plant
Commenter Affiliation: David W. Peightal
Document Control Number: EPA-HQ-OAR-2002-0058-3424
Comment Excerpt Number: 5

Comment: DGC agrees with EPA that a more appropriate option of using oxygen trim systems in lieu of oxygen monitoring in a oxygen stratified situations to optimize the fuel ratio and combustion efficiency. DGC would like the option to use multiple oxygen monitors sufficient to mitigate the stratification issue for effective combustion efficiency to indirectly measure the oxygen trim.

Response: The EPA thanks the commenter for their support of using oxygen trim systems in lieu of oxygen monitoring. For a response to the request that multiple pre-existing oxygen monitors be allowed to demonstrate compliance in lieu of the oxygen trim system, please see comment EPA-HQ-OAR-2002-0058-3449-A1, excerpt 17.

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific LLC (GP)

Document Control Number: EPA-HQ-OAR-2002-0058-3465-A1

Comment Excerpt Number: 30

Comment: As proposed, regulated Boilers are required to complete and annual stack test and establish a minimum oxygen level for compliance monitoring purposes. The minimum oxygen requirement is then paired with the requirement to have an oxygen analyzer system and trim system to maintain the oxygen above this minimum established level. This approach is advantageous from a compliance demonstration perspective in that it eliminates the need to have costly CO-CEMS on all boilers. While oxygen is a reasonable surrogate, there are times when the CO and oxygen concentrations may diverge. These discrepancies may be particularly apparent during boiler swings or other intermittent transitory periods. Therefore, to provide the regulated community with an appropriate level of compliance assurance, EPA should make it clear that the oxygen limits are the only applicable compliance demonstration for CO in the periods between the annual tests. In other words, oxygen is a true surrogate and EPA has no expectation that short term CO will comply with the prescribed 3-hour CO limits during every 3-hour period over the course of an operating year.

Response: The EPA has set two distinct compliance paths in this rule. Sources using certified CO CEMS will comply with a ten day rolling average limit, while sources without certified CO CEMS systems comply by conducting an annual stack test and correlating O₂ CEMS or O₂ trim readings to the lowest O₂ reading obtained during the stack test, based on a three hour average.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 102

Comment: Many existing boilers and process heaters utilize flue gas oxygen analyzers for indication, alarm, and O₂ trim control, where the air-to-fuel ratio is automatically controlled for optimum combustion conditions. For many types of combustion units, O₂ monitoring occurs upstream of potential air inleakage points like preheaters, thus minimizing the potential for erroneous measurements. For these units already equipped with existing O₂ analyzer systems and/or O₂ trim systems, monitoring data from these locations are currently being used both for boiler tuning and combustion control. Therefore, if O₂ monitoring is provided as an alternative to demonstrate continuous compliance with CO limits under the Boiler MACT rule, it would be logical and technically feasible for these facilities to continue monitoring O₂ at that current location. These O₂ analyzers are not compliance CEMS and therefore do not meet PS-3 requirements. However, they are calibrated and maintained to provide reliable and safe service for combustion unit operation. Proper maintenance and calibration routines are the only available option, given the inability to certify these monitors, according to applicable Performance Specifications, when located at the outlet to the boiler. This inability to certify is caused by stratification of gases at the boiler/process heater outlet.

Therefore, the most cost effective and technically feasible approach for utilization of O₂ analyzer systems would be to:

- Allow the continued use of existing O₂ analyzers

- Allow the installation of new O₂ analyzers of appropriate design at optimal locations, and
- Allow periodic sensor calibration as an alternative to certification and as a way to ensure accurate O₂ monitoring.

Boiler combustion and optimization experts indicate that most O₂ trim systems rely on O₂ measurements at the outlet of the boiler combustion chamber. These analyzers are not certified, but are employed successfully to implement control strategies. The monitoring strategy proposed above is therefore viable even if it is not connected to an automated trim system.

Response: The EPA agrees with the commenter and verifies that certified O₂ CEMS, O₂ monitors, and O₂ trim systems are permissible compliance systems for the short term compliance option in this rule.

Commenter Name: David A. Buff, Golder Associates Inc.

Commenter Affiliation: Florida Sugar Industry (FSI)

Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1

Comment Excerpt Number: 18

Comment: Many existing boilers and process heaters already utilize flue gas oxygen analyzers for indication, alarm, and O₂ trim control where the fuel-to-air ratio is automatically controlled for optimum combustion conditions. For many types of combustion units, O₂ monitoring occurs upstream of any potential air in-leakage points, thus minimizing the potential for erroneous measurements. For those units already equipped with existing O₂ sensors and/or O₂ trim control systems, monitoring data from these locations are currently being used both for boiler tuning and combustion control. Therefore, if O₂ monitoring is provided as an alternative to demonstrate continuous compliance under the Boiler MACT Rule, it would be logical and technically feasible for these facilities to continue monitoring O₂ at that current location.

However, O₂ analyzers utilized for these existing purposes do not comply with Performance Specification 3 (PS-3) requirements regarding their positioning or other QA/QC standards. They are calibrated and maintained to provide reliable and safe service for combustion unit operation. Proper maintenance and calibration routines are the only available option, given the inability to certify these monitors according to applicable Performance Specifications, when the monitors are located at the outlet to the boiler. This inability to certify is caused by stratification of gases at the boiler/process heater outlet.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 102.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 37

Comment: Many existing boilers already utilize flue gas oxygen analyzers for indication, alarm, and O₂ trim control, where the fuel/air ratio is automatically controlled for optimum combustion conditions. The sensing location for existing O₂ monitors is typically in the optimum location to sense flue gas composition as reliably as possible, because sensing of oxygen in these

cases maintains proper excess air levels and helps prevent unsafe operating conditions. For many types of combustion units, that location is near the boiler furnace outlet in a position upstream of any potential air leakage points to avoid erroneous excess air indications which would drive controls in an erroneous direction. This location is also upstream of air preheaters, thus avoiding the erroneous (high O₂) indications due to inherent leakage across regenerative air preheater seals or potential tube leakage in recuperative air preheaters. For those units equipped with existing O₂ sensors and O₂ trim control systems, flue gas composition at those locations would already be used for combustion tuning and control characterization. Therefore, if O₂ monitoring is desired for continuous compliance under the Boiler MACT rule, sensing O₂ at that current location would be logical and proper from a technical perspective.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 102.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 67

Comment: In the March 21, 2011 final rule, EPA included continuous oxygen monitoring as the compliance method for sources with a CO limit, instead of mandating the use of CO CEMS. EPA now proposes to amend the oxygen monitoring requirements (76 FR 80609, Dec. 23, 2011) to allow for the use of continuous oxygen trim analyzer systems instead of oxygen CEMS. EPA is also removing the requirement that the oxygen monitor be located at the outlet of the boiler, so that it can be located either within the combustion zone or at the outlet as a flue gas oxygen monitor. We support EPA's proposal to add flexibility and reduce the cost and burden of the continuous oxygen monitoring requirements, as these changes allow facilities to utilize existing oxygen trim systems rather than installing CEMS.

Many existing boilers already utilize flue gas oxygen analyzers for indication, alarm, and O₂ trim control, where the fuel/air ratio is automatically controlled for optimum combustion conditions. The sensing location for existing O₂ monitors is typically in the optimum location to sense flue gas composition as reliably as possible, because sensing of oxygen in these cases maintains proper excess air levels and helps prevent unsafe operating conditions. For many types of combustion units, that location is near the boiler furnace outlet in a position upstream of any potential air inleakage points to avoid erroneous excess air indications which would drive controls in an erroneous direction. This location is also upstream of air preheaters where utilized, thus avoiding the erroneous (high O₂) indications due to inherent leakage across regenerative air preheater seals or potential tube leakage in recuperative air preheaters. For those units equipped with existing O₂ sensors and O₂ trim control systems, flue gas composition at those locations would already be used for combustion tuning and control characterization. Therefore, if O₂ monitoring is desired for continuous compliance under the Boiler MACT rule, sensing O₂ at that current location would be logical and proper from a technical perspective.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 102.

Commenter Name: Randall D. Quintrell

Commenter Affiliation: Georgia Paper & Forest Products Association

Document Control Number: EPA-HQ-OAR-2002-0058-3451-A1

Comment Excerpt Number: 12

Comment: Oxygen monitoring corrections are necessary. The rule's proposal requiring that the oxygen trim control be used to maintain CO emissions compromises safe boiler operation. Instead of oxygen trim control, the Agency should allow the use of existing (or new) O₂ probes or analyzers situated at the boiler outlet as a surrogate CO compliance assurance monitoring strategy.

Response: For a response to the request that pre-existing or new oxygen probes situated at the boiler outlet to be allowed to demonstrate compliance in lieu of the oxygen trim system, please see comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 102.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 103

Comment: While O₂ trim systems are viable for combustion control, there are limitations to its applicability that are especially pertinent for multi-fuel and biomass boilers.

- O₂ trim systems are best suited when the boiler predominantly burns only one type of fuel.
- Feedback control loops in O₂ trim systems are generally developed only for the predominant fuel. This limits the applicability of O₂ trim systems for multi-fuel units.
- O₂ trim systems are used as a means of "fine" control and are sometimes ineffective when there are frequent changes in fuel quality and mix. This limitation would apply to combination boilers co-firing biomass fuels.

While it is theoretically possible to develop control systems for each individual fuel used in a multi-fuel boiler, this approach is often expensive and may be ineffective.

Given these factors, it is our recommendation that facilities be given the option to use either the O₂ monitoring approach (install, calibrate, and monitor O₂ without the requirement to certify) or an O₂ trim system.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 102.

Commenter Name: David A. Buff, Golder Associates Inc.

Commenter Affiliation: Florida Sugar Industry (FSI)

Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1

Comment Excerpt Number: 20

Comment: While O₂ trim systems are used for combustion control, there are limitations to their applicability that are especially pertinent for multi-fuel and biomass boilers:

O₂ trim systems are best suited when the boiler predominantly burns only one type of fuel.

Feedback control loops in O2 trim systems are generally developed only for the predominant fuel. This limits the applicability of O2 trim systems for multi-fuel units.

O2 trim systems are used as a means of "fine" control and are sometimes ineffective when there are frequent changes in fuel quality and mix. This limitation would apply to combination boilers co-firing biomass fuels.

While it is theoretically possible to develop control systems for each individual fuel used in a multi-fuel boiler, this approach is often expensive and may be ineffective.

Given these factors, FSI recommends that facilities be given the option to use either the O2 monitoring approach (install, calibrate, and monitor O2 without the requirement to certify) or an O2 trim system.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 102.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 68

Comment: Oxygen sensing location

The Oxygen analyzer system is defined in §63.7575 in part as follows:

Oxygen analyzer system means all equipment required to determine the oxygen content of a gas stream and used to monitor oxygen in the boiler flue gas or firebox.

The optimum location of the sensor or sampling point is dependent on the specific boiler design. In different applications, that location might be at the furnace exit, in the convection pass, at the boiler outlet, or at another downstream location. We recommend that this language be modified as follows to allow latitude in the exact location of the sensing point:

Oxygen analyzer system means all equipment required to determine the oxygen content of a gas stream and used to monitor oxygen in the boiler or process heater flue gas, boiler/process heater ~~or~~ firebox, or other appropriate intermediate location.

Response: The EPA agrees with the commenter and has modified the rule language to read “Oxygen analyzer system means all equipment required to determine the oxygen content of a gas stream and used to monitor oxygen in the boiler or process heater flue gas, boiler/process heater, firebox, or other appropriate location.”

Commenter Name: David A. Buff, Golder Associates Inc.

Commenter Affiliation: Florida Sugar Industry (FSI)

Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1

Comment Excerpt Number: 21

Comment: "Oxygen analyzer system" is defined in §63.7575 in part as follows:

Oxygen analyzer system means all equipment required to determine the oxygen content of a gas stream and used to monitor oxygen in the boiler flue gas or firebox.

The optimum location of the sensor or sampling point is dependent on the specific boiler design. In different applications, that location might be at the furnace exit, in the convection pass, at the boiler outlet, or at another downstream location. To allow latitude in the exact location of the sensing point, this language should be modified by adding the underlined language, to read as follows:

Oxygen analyzer system means all equipment required to determine the oxygen content of a gas stream and used to monitor oxygen in the boiler firebox, boiler flue gas, or other appropriate intermediate location.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 68.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 38

Comment: The optimum location of the sensor or sampling point is dependent on the specific boiler design. In different applications, that location might be at the furnace exit, in the convection pass, at the boiler outlet, or at another downstream location. ACC recommends that this language be modified as follows to allow latitude in the exact location of the sensing point:

Oxygen analyzer system means all equipment required to determine the oxygen content of a gas stream and used to monitor oxygen in the boiler or process heater flue gas, boiler/process heater or firebox, or other appropriate intermediate location.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 68.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 104

Comment: The optimum location of the sensor or sampling point is dependent on the specific boiler design. In different applications, that location might be at the furnace exit, in the convection pass, at the boiler outlet, or at another downstream location. To allow latitude in the exact location of the sensing point, this language should be modified by adding the underlined language, to read as follows:

Oxygen analyzer system means all equipment required to determine the oxygen content of a gas stream and used to monitor oxygen in the boiler flue gas, boiler ~~or~~ firebox, or other appropriate intermediate location.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 68.

Commenter Name: Michael L. Krancer

Commenter Affiliation: Pennsylvania Department of Environmental Protection (DEP)

Document Control Number: EPA-HQ-OAR-2002-0058-3507-A1

Comment Excerpt Number: 7

Comment: The final rule required oxygen monitoring at the outlet of the boiler combustion chamber to ensure good combustion. Instead of this requirement, the proposed reconsideration requires the installation, calibration and use of oxygen trim systems to optimize air-to-fuel ratio and combustion efficiency.

The DEP agrees with the EPA that the use of oxygen trim systems is an appropriate control for efficient combustion and a less burdensome alternative to monitoring stack oxygen concentration. Additionally, the EPA should also provide for case-by-case approval of alternative systems that can be demonstrated to meet the intent of this requirement.

Response: The EPA thanks the commenter for their support of the use of oxygen trim systems as a control for efficient combustion.

For response to alternate O₂ monitoring systems, see comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 102.

The EPA agrees with the commenter and notes that 40 CFR 63.8(f) presents the procedure for submitting a request to the Administrator to use alternative monitoring.

Commenter Name: Shannon S. Broome

Commenter Affiliation: Auto Industry Forum (AIF)

Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1

Comment Excerpt Number: 1

Comment: As a variation on EPA's compliance method for the stack test-based CO limits, for units that experience significant operational variability, EPA could establish a performance standard (e.g., a work practice approach where good combustion was monitored by some indicator and fluctuations outside the range observed during the stack test triggered corrective action) that would apply during the periods between stack tests, rather than a strict compliance monitoring approach. Such a standard could consist of a numeric value indicative of good combustion, such as oxygen or CO levels in the furnace or stack, but values outside of the range observed during a performance test (or in the case of a continuous CO monitor, above the stack test-based standard) would not constitute a violation of the underlying stack test-based CO standard, as long as appropriate corrective action were taken within a reasonable time after the exceedance was measured or documentation was made for non-correctable conditions (e.g., a load swing or start-up condition). The source could determine if it wanted to comply using a three-hour stack test and the oxygen monitoring approach already included in the rule, or, due to the influence of variable conditions highlighted above, opt for a periodic three-hour stack test with a performance standard in between stack tests.

In concept, such an approach would be analogous to bag leak detection systems on fabric filters, which EPA routinely requires in its standards. When a leaking bag is detected, EPA's rules

typically do not define such an event as a violation. Instead, the affected source is required to replace the leaking bag and only might be found in violation if this corrective action is not taken within a specified period. So, there is clear precedent for applying this concept to the Industrial Boiler MACT stack test CO standards.

EPA has ample justification to adopt this approach as a work practice under § 112(h). Among other things, EPA is authorized to adopt work practices under § 112(h) when "the application of measurement methodology to a class of sources is not practicable due to technological and economic limitations." That is the case with the Boiler MACT stack-test-based CO emissions limitations for sources that experience significant operational variability. While it is true that certain relevant constituents such as oxygen and CO can be measured, the "application" of such methods may not be technologically practicable in some cases, because the data that are collected cannot reasonably be used to show compliance with a stack test-based CO limit. For sources using this approach, the performance data largely would be taken during periods when the affected source was not operating under the same steady state, high-load conditions as existed during the stack tests used to set the standards. Thus, EPA has authority and justification to set performance standards for the periods between stack tests.

Response: The EPA disagrees with the commenter in that CO and O₂ monitoring of affected sources are not sufficiently impracticable to trigger work practice standards as allowed by § 112(h); The EPA has a long history of using parametric monitoring in rules.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 101

Comment: However, we would like to highlight the following inconsistency between preamble language and rule requirements as it pertains to O₂ monitoring requirements: • Preamble language (section G (9)) indicates that boilers and process heaters need to install, calibrate, and operate an oxygen trim system in order to ensure efficient combustion and compliance with the CO standards.

By comparison, as per the requirements under § 63.7525(a), if your boiler or process heater is subject to a carbon monoxide emission, you must install, operate, and maintain an oxygen analyzer system as defined in § 63.7575. By definition, *an oxygen analyzer system* "means all equipment required to determine the oxygen content of a gas stream and used to monitor oxygen in the boiler flue gas or firebox. This definition includes oxygen trim systems."

It is our understanding from the rule language that facilities can utilize an oxygen analyzer system (with one of the options being the use of an automated oxygen trim system) to demonstrate compliance with the metrics identified during the performance test. EPA should clarify the rule language to this effect.

The language related to parameter monitoring provided in § 63.7525(a)(2) and Table 4 seems to further clarify issue 1 above – Under the requirements under §63.7525 (a)(2), oxygen trim systems should be operated *with the oxygen level "set"* at the minimum percent oxygen by volume that is established as the operating limit for oxygen. By contrast, as indicated in Table 4,

facilities using oxygen analyzer systems as monitoring devices, as specified in § 63.7525(a), *should maintain the oxygen level* such that it is not below the lowest hourly average oxygen concentration measured during the most recent CO performance tests (use that as the set-point when using O₂ trim whereas maintain it at or above that level when using O₂ monitoring.)

Response: For response to alternate O₂ monitoring systems, see comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 102.

In response to oxygen monitoring limits, the EPA agrees with the commenter that the rule language was inconsistent and has modified the rule to align the requirements of §63.7525 (a)(2), with those indicated in Table 4.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 93

Comment: Paragraph 63.7525(a)(2) references Table 4 (Operating Limits Table), which in turn, establishes the oxygen operating limit as an hourly average. However, Table 8, which establishes continuous compliance parameters, specifies the oxygen operating limit as a 30-day rolling average. Thus, the oxygen compliance requirements in §63.7525(a)(2), Table 4 and Table 8 are all inconsistent. BPH require operation with some excess air (higher oxygen) at lower operating rates simply due to lower fuel and air velocities, degraded mixing of fuel and air as those flow rates decrease, and lower furnace temperatures. Therefore, it is necessary for the actual oxygen trim system set point to vary over load, with the lowest set point typically occurring at or near full load operation. The Table 8 language accommodates this operating variability and is consistent with the 30 day rolling average used for most operating parameters in the rule. Therefore, we recommend Table 4 and §63.7525(a)(2) be changed to the Table 8 requirement (i.e., "Maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen level measured during the most recent carbon monoxide performance test.")

Response: See the response to comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 101.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 94

Comment: Proposed §63.7525(a)(2) requires that the oxygen trim system for CO monitoring be operated "with the oxygen level set at the minimum percent oxygen by volume that is established as the operating limit." However, this operating limit is a minimum and not a fixed value, thus, if §63.7525(a)(2) is not changed as recommended in the previous paragraph, §63.7525(a)(2) needs to be revised to require the oxygen trim system be operated "with the oxygen level set no lower than the minimum percent oxygen." This change will also make (a)(2) consistent with the referenced Table 4 wording of this requirement.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 101.

Commenter Name: David A. Buff, Golder Associates Inc.

Commenter Affiliation: Florida Sugar Industry (FSI)

Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1

Comment Excerpt Number: 11

Comment: There is an inconsistency between the preamble language and rule requirements as it pertains to O₂ monitoring requirements:

Preamble language (section G (9)) indicates that boilers and process heaters *are required to install, calibrate, and operate an oxygen trim system* in order to ensure efficient combustion and compliance with the CO standards.

By comparison, § 63.7525(a) states that if the boiler or process heater is subject to a carbon monoxide emission, *you must install, operate, and maintain an oxygen analyzer system* as defined in § 63.7575. By definition, *an oxygen analyzer system* "means all equipment required to determine the oxygen content of a gas stream and used to monitor oxygen in the boiler flue gas or firebox. This definition includes oxygen trim systems."

It is our understanding from the rule language that facilities can utilize an oxygen analyzer system, with the option of using an automated oxygen trim system, to demonstrate compliance with the parameters identified during the performance test. EPA should clarify the rule language to this effect.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 101.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 40

Comment: The wording of § 63.7525(a)(2) above is more restrictive than the wording in Table 8, item 9 (c) as shown below:

"Maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen level measured during the most recent carbon monoxide performance test."

The Table 8 language allows operation with the 30-day rolling average oxygen level at or above (no lower than) the lowest 1-hour average oxygen level measured in the most recent performance test whereas the § 63.7525(a)(2) wording requires continuous operation at the minimum oxygen percent established during the prior test. Inherent boiler operating characteristics require operation with higher excess air (higher oxygen) at lower operating rates simply due to lower fuel and air velocities, degraded mixing of fuel and air as those flow rates decrease, and lower furnace temperatures. Therefore, it is necessary for the actual oxygen trim system set point to vary over load, with the lowest set point typically occurring at or near full load operation. The Table 8 language accommodates this operating requirement, and ACC believes Table 4 and § 63.7525(a)(2) need to be revised to provide similar operating latitude.

Response: For issues with inconsistency between the rule language and wording in Table 4 regarding operating limits for oxygen levels, please see comment EPA-HQ-OAR-2002-0058-3521, excerpt 101. For a response to issues with inconsistency between the rule language and the wording in Table 8, please see comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 93.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 41

Comment: The wording of § 63.7525(a)(2) above is more restrictive than the wording in Table 8, item 9 (c) as shown below:

"Maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen level measured during the most recent carbon monoxide performance test."

The Table 8 language allows operation with the 30-day rolling average oxygen level at or above (no lower than) the lowest 1-hour average oxygen level measured in the most recent performance test whereas the § 63.7525(a)(2) wording requires continuous operation at the minimum oxygen percent established during the prior test. Inmate boiler operating characteristics require operation with higher excess air (higher oxygen) at lower operating rates simply due to lower fuel and air velocities, degraded mixing of fuel and air as those flow rates decrease, and lower furnace temperatures. Therefore, it is necessary for the actual oxygen trim system set point to vary over load, with the lowest set point typically occurring at or near full load operation. The Table 8 language accommodates this operating requirement, and ACC believes Table 4 and § 63.7525(a)(2) need to be revised to provide similar operating latitude.

Response: For issues with inconsistency between the rule language and wording in Table 4 regarding operating limits for oxygen levels, please see comment EPA-HQ-OAR-2002-0058-3521, excerpt 101. For a response to issues with inconsistency between the rule language and wording in Table 8, please see comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 93.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 70

Comment: The Table 8 language allows operation with the 30-day rolling average oxygen level at or above (no lower than) the lowest 1-hour average oxygen level measured in the most recent performance test whereas the §63.7525(a)(2) wording requires continuous operation at the minimum oxygen percent established during the prior test. Inmate boiler operating characteristics require operation with higher excess air (higher oxygen) at lower operating rates simply due to lower fuel and air velocities, degraded mixing of fuel and air as those flow rates decrease, and lower furnace temperatures. Therefore, it is necessary for the actual oxygen trim system set point to vary over load, with the lowest set point typically occurring at or near full load operation. The Table 8 language accommodates this operating requirement and Table 4 and §63.7525(a)(2) need to be revised to provide similar operating latitude.

Response: For issues with inconsistency between the rule language and wording in Table 4 regarding operating limits for oxygen levels, please see comment EPA-HQ-OAR-2002-0058-3521, excerpt 101. For a response to issues with inconsistency between the rule language and wording in Table 8, please see comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 93.

Commenter Name: Responsible Citizens

Commenter Affiliation: John Smith

Document Control Number: EPA-HQ-OAR-2002-0058-3531-A1

Comment Excerpt Number: 1

Comment: Demonstrating compliance: EPA has proposed to use CO limits as a surrogate for organic HAPs. In its floor-setting work, EPA had access to results from thousands of CO emission tests, in addition to a much smaller amount of continuous CO CEM data. The emission test data was mostly made up of standard three-run emission test results. When EPA evaluated this data, it produced floor limits far stricter than the current proposed rule. Industry protested (and EPA apparently agreed) that these three-run test results are not representative of real operation, even though for decades these same industrial interests have submitted test results to state and federal agencies without pointing out that the test results weren't representative of real operation. To the contrary, industrial sites have often used these very three-run test results as the basis for certifying continuous compliance with Title V permit conditions that limit CO emissions.

EPA is now proposing relatively lenient CO limits (compared to the initial rule), and allowing sites to demonstrate compliance with the same three-run tests that industry, only a few months ago, said weren't representative of long-term operation. CO CEMS are inexpensive, reliable and proven technology. CO CEMS should be required for every boiler larger than 10 MMBtu/hr heat input. EPA and industry cannot in one moment say that three-run test data is inaccurate/non-representative for purposes of establishing limits, then a moment later say that three-run annual tests are appropriate for showing continuous compliance. It's no secret among agencies, industry, and emission testers that for decades, many industrial sites have "prepped" their boilers prior to compliance tests specifically for the purpose of passing three runs of CO emission tests. For the other 8700+ hours of the year, these sites had no reason to manage or monitor CO emissions.

EPA's proposal to require an oxygen trim system to assure continuous compliance is inadequate. EPA's proposed rule doesn't require these systems to be calibrated to any objective standards, instead referring only to manufacturer's recommendations. Thus, an off-the-shelf O2 trim system whose manufacturer does not include specific calibration standards will not be required to carry out systematic calibrations. These facilities can decide for themselves what calibration is appropriate. If O2 trim systems are used to assure continuous compliance with the CO standards, then there must be specific calibration requirements that the public can know are being implemented.

Since very few industrial sites have ever had to manage CO emissions, very few sites really know what their boilers are capable of with respect to CO emissions. It shouldn't surprise permittees that MACT standards may take some effort to meet. Yet industry comments consistently say the CO standards can't be met, even though they don't say what levels they can achieve (and even though there are thousands of emission test results in EPA's own records that

show compliance with these standards, results which industry has never discredited until this rule action). Combustion experts all say that far better CO performance can be readily and cost-effectively achieved by improved combustion management-related efforts, whether this be work practices, new software, or modifications to the combustion air systems.

Response: The EPA disagrees with the commenter that the use of O₂ trim systems constitutes inadequate monitoring, or that specific calibration requirements are necessary to ensure compliance with the CO standards in the rule. The O₂ trim system or O₂ monitor required by the rule will be correlated to a calibrated CO instrument during annual performance testing. The EPA recognizes that operating an O₂ trim system benefits the source through lower fuel costs by increasing combustion efficiency, simultaneously lowering CO emissions. In this respect the source is incentivized to operate the O₂ trim system calibrated according to manufacturer's specification, and maintain optimal combustion.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 91

Comment: The definition of oxygen trim system in proposed §63.7575 suggests that the oxygen trim system must automatically adjust excess air, by identifying an automatic system as the "typical" example. For many smaller BPH, limited use BPH, BPH that normally operate at a fixed load, and process heaters where computer control systems are unavailable, automatic systems are not always in place, not always justified, and would be costly to install. The cost for installing and maintaining such automatic systems has not been included in the analyses supporting this rulemaking. Furthermore, even where automatic systems are in place, during startups and shutdowns and other special operations, it is often necessary to operate the automatic system manually to assure the firebox is not starved for air. While we support the change to an oxygen trim system from an oxygen CEMS, we do not believe such a system should be required to be automatic or that the costs of such a requirement have been considered. Therefore, the wording of the example in the oxygen trim system definition should be changed by deleting the word "automatically".

Response: The EPA thanks the commenter for their support of oxygen trim systems as a compliance alternative to oxygen CEMS.

We understand that the commenter is referring to an oxygen monitoring system, and not an oxygen trim system. A source operator may comply with the rule through the use of either system.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 92

Comment: Not all boilers and process heaters are equipped with oxygen or CO monitors. Small units, in particular, may simply have a manual draft control. The oxygen trim requirement applies to all BPH of <10 MMBTU/hr and thus applies to some units that do not have such monitors. Use of manual draft control should be specifically allowed, where a boiler or process heater is not equipped with an oxygen or CO monitor.

Response: Small units, those with heat input capacity below 10 million Btu per hour, are not subject to emission limits and, thus, are not required to monitor oxygen or CO.

11B02. Oxygen Monitors-Specifications/Operations

Commenter Name: Randall D. Quintrell

Commenter Affiliation: Georgia Paper & Forest Products Association

Document Control Number: EPA-HQ-OAR-2002-0058-3451-A1

Comment Excerpt Number: 13

Comment: Requiring periodic O₂ probe calibration would be a means to ensure reliability of the probes' accuracy; however, requiring Performance Specification 3 level requirements is unjustified, and is impractical unless the O₂ measurement is made at the stack. As we stated in our prior comments for the March 2011 rule, at a boiler outlet ahead of the stack, there is no way to accomplish the testing or meet the conditions for certification under PS3 for any kind of gas monitor.

Response: The EPA agrees with the commenter and has clarified the rule language to include PS-3 certified O₂ CEMS, O₂ monitors, and O₂ trim systems.

Commenter Name: Bruce W. Ramme

Commenter Affiliation: Wisconsin Electric Power Company (WE Energies)

Document Control Number: EPA-HQ-OAR-2002-0058-3452-A1

Comment Excerpt Number: 2

Comment: If the oxygen analyzer option is selected, two further requirements apply. A minimum oxygen level operating limit (oxygen set point) applies (40 CFR Part 63, Table 4, Item 9), as does a requirement to continuously monitor the oxygen content using an oxygen trim system. A 30-day rolling average limit is then imposed on the oxygen trim system.

A 30-day rolling average limit for oxygen content is redundant with the oxygen level operating limit. The oxygen level operating limit should adequately demonstrate continuous compliance. We Energies requests that EPA remove the requirement in 40 CFR Part 63, Table 8, Item 9 to continuously monitor oxygen content on a 30-day rolling average.

Response: In response to oxygen monitoring limits, the EPA agrees with the commenter that the rule language was inconsistent and has modified the rule to align the requirements of §63.7525 (a)(2), with those indicated in Table 4. As such we feel that a 30-day rolling average limit is appropriate for demonstration of compliance with the rule.

Commenter Name: Richard D. Garber
Commenter Affiliation: Boise Inc.
Document Control Number: EPA-HQ-OAR-2002-0058-3686-A2
Comment Excerpt Number: 23

Comment: The appropriateness of using an oxygen trim system for continuous monitoring of all periods between source tests should be further examined. While the minimum oxygen level established during the performance test, using maximum range steaming rate and fuel feed rates, may be appropriate for boilers with a single fuel source, its appropriateness for boilers with multiple fuel sources may be questionable. Boise has been directly involved with discussions pertaining to this issue with boiler vendors and consultants. Multiple fuel boilers will likely have several different excess air and combustion profiles depending on the mix of the various fuels. Boise suggests that use of the oxygen analyzer system for establishing a "set point" for monitoring purposes may be technically more appropriate. Use of oxygen trim systems for feed-forward combustion control purposes with the requirement to *maintain* the minimum oxygen level as a 30-day average would seem to us to be reaching beyond the technical capability of many of these systems.

Response: The EPA has included language in the rule that may require more than one stack test to determine pollutant concentrations from multiple fuels. It may be advisable for a source operator to determine their minimum O₂ level from the various fuels they normally combust. We have included three different O₂ measurement approaches in the rule to accommodate the varied compliance needs of different facilities.

Commenter Name: Lenny Dupuis
Commenter Affiliation: Dominion Resources Services, Inc.
Document Control Number: EPA-HQ-OAR-2002-0058-3486-A1
Comment Excerpt Number: 9

Comment: We also support the option to install oxygen trim systems as a less costly and less burdensome alternative to oxygen CEMS for units subject to CO limits. However, we have concerns with the requirement (specified in Table 4 to 40 CFR 63 Subpart DDDDD) to maintain an oxygen level based on the lowest hourly average oxygen concentration measured during the most recent CO performance test. The limit derived from a performance test period does not include the complete mix of fuels and range of fuel characteristics that may be encountered over the course of an operating year and would restrict operational flexibility to deal with fuel variations. This is of particular concern for biomass units which combust fuels of varying heating value and moisture content.

Response: The EPA thanks the commenter for their support of oxygen trim systems as a compliance alternative. For a response to issues with multi-fuel boilers maintaining an oxygen level based on the lowest hourly average oxygen concentration measured from the most recent performance test, please see comment EPA-HQ-OAR-2002-0058-3686-A2, excerpt 23.

Commenter Name: David A. Buff, Golder Associates Inc.
Commenter Affiliation: Florida Sugar Industry (FSI)

Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1

Comment Excerpt Number: 17

Comment: Hawaii Commercial & Sugar Company ("HC&S") in Hawaii has three multi-fuel hybrid suspension grate boilers that fire bagasse, coal, fuel oil and blends of these fuels. For multi-fueled boilers, like the ones at HC&S, the optimum air-to-fuel ratios will vary depending upon the fuel or fuel mixture being fired. The Proposed Boiler MACT Rule does not clearly explain how such boilers should determine the minimum O₂ level. The FSI believes such boilers should be allowed to develop minimum O₂ levels for each fuel and then comply with the minimum O₂ level that is appropriate for the fuel that is being fired.

Response: We disagree that the rule needs to be revised to address the commenter's issue of multi-fuel boilers maintaining an oxygen level based on the lowest hourly average oxygen concentration measured from the most recent performance test. See the response to comment EPA-HQ-OAR-2002-0058-3686-A2, excerpt 23.

Commenter Name: David A. Buff, Golder Associates Inc.

Commenter Affiliation: Florida Sugar Industry (FSI)

Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1

Comment Excerpt Number: 16

Comment: The FSI also has examined the O₂ data that were measured during the EPA reference method relative accuracy testing for CO for U.S. Sugar Boiler No. 8 during each of the 3 years (2009-2011). The relative accuracy CO data were used to determine what the O₂ levels were during stack testing, because under the Proposed Boiler MACT Rule stack testing would set the operating limit each year for the boiler. The O₂ levels during these CO tests are shown in Table B-1 of Appendix B. [See submittal for Appendix B] The data show that the O₂ levels can vary during the testing, which is helpful in establishing a minimum O₂ level. In this case, all testing was performed during the same time of the season (December).

Given these data, it appears that a hybrid suspension grate bagasse-fired boiler could be tested relatively early in the crop season, because there is sufficient variability to set a reasonable minimum O₂ level for the remainder of the year. The final Boiler MACT Rule should allow multiple CO tests during a year, if necessary, to provide a source the flexibility to determine the minimum O₂ level that meets the CO limit.

Response: The EPA thanks the commenter for their support of O₂ monitoring in the rule. The rule allows for testing while firing various fuel configurations to determine the best compliance options, and places no stipulations on time of year such tests are performed. We recommend that source operators with varying fuels carefully consider each fuel condition they wish to test.

Commenter Name: David A. Buff, Golder Associates Inc.

Commenter Affiliation: Florida Sugar Industry (FSI)

Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1

Comment Excerpt Number: 19

Comment: The most cost effective and technically feasible approach for utilization of O₂ analyzer systems would be to:

- Allow the continued use of existing O₂ analyzers
- Allow the installation of new O₂ analyzers of appropriate design at optimal locations, and
- Allow periodic sensor calibration as an alternative to certification and as a way to ensure accurate O₂ monitoring.

Boiler combustion and optimization experts indicate that most O₂ trim systems rely on O₂ measurements at the outlet of the boiler combustion chamber. These analyzers are not certified, but are employed successfully to implement control strategies. The monitoring strategy proposed above is therefore viable, even if the O₂ analyzer is not connected to an automated trim system.

Response: The EPA agrees with the commenter and has modified the rule language to allow flexibility and use of existing and new O₂ monitors and trim systems of various types.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 105

Comment: We believe §63.7525(a)(2) should reference Table 7, not Table 4, since that is the table with the requirements for establishing operating limits. Second, the wording of above is more restrictive than the wording in Table 8, item 9 (c).

The Table 8 language allows operation with the 30-day rolling average oxygen level at or above (no lower than) the lowest 1-hour average oxygen level measured in the most recent performance test whereas the §63.7525(a)(2) wording requires continuous operation at the minimum oxygen percent established during the prior test. Inherent boiler operating characteristics require operation with higher excess air (higher oxygen) at lower operating rates simply due to lower fuel and air velocities, degraded mixing of fuel and air as those flow rates decrease, and lower furnace temperatures. Therefore, it is necessary for the actual oxygen trim system set point to vary over load, with the lowest set point typically occurring at or near full load operation. The Table 8 language accommodates this operating requirement and Table 4 and §63.7525(a)(2) need to be revised to provide similar operating latitude.

Response: For a response to issues with inconsistencies between the rule language and Table 8, please see comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 93 under the chapter Oxygen Monitors - Appropriateness and Location of.

Table 7 provides instruction on how to establish operating limits, while Table 4 provides instruction on how the limits are applied in the rule.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 69

Comment: Oxygen trim system set point

Paragraph 63.7525(a)(2) states:

"You must operate the oxygen trim system with the oxygen level set at the minimum percent oxygen by volume that is established as the operating limit for oxygen according to Table 4 to this subpart."

First, we believe this paragraph should reference Table 7, not Table 4, since that is the table with the requirements for establishing operating limits. Second, the wording of §63.7525(a)(2) above is more restrictive than the wording in Table 8, item 9 (c) as shown below:

"Maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen level measured during the most recent carbon monoxide performance test."

Response: For a response to the reference error in 63.7525(a)(2), please see comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 105. For a response to issues with inconsistencies between the rule language and Table 8, please see comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 93 under the chapter Oxygen Monitors - Appropriateness and Location of.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 39

Comment: *Oxygen trim system set point*

Paragraph (2) of proposed § 63.7525(a) states:

"You must operate the oxygen trim system with the oxygen level set at the minimum percent oxygen by volume that is established as the operating limit for oxygen according to Table 4 to this subpart."

ACC believes this paragraph should reference Table 7, not Table 4, since that is the table with the requirements for establishing operating limits.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 105.

Commenter Name: David A. Buff, Golder Associates Inc.

Commenter Affiliation: Florida Sugar Industry (FSI)

Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1

Comment Excerpt Number: 22

Comment: Paragraph 63.7525(a)(2) states:

"You must operate the oxygen trim system with the oxygen level set at the minimum percent oxygen by volume that is established as the operating limit for oxygen according to Table 4 to this subpart."

This paragraph should reference Table 7, not Table 4, since that is the table with the requirements for establishing operating limits.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 105.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 71

Comment: In addition, solid or liquid fuel fired boilers and process heaters subject to the CO limits in this rule may also be equipped to fire other liquid or gas fuels that may be able to allow the unit to operate at lower oxygen levels for improved boiler efficiency. Alternatively, they may also fire biomass or other traditional fuels that require higher excess air for improved combustion. Operators may also need to modify the oxygen setpoint or trim system to accommodate boiler or fuel quality issues. EPA needs to recognize that oxygen trim systems not only provide a means for energy efficiency, but they also are integral to furnace combustion control and furnace safety. While use of a 30-day rolling average does provide some operating latitude, this rule should not needlessly restrict operator latitude relative to safety or operating efficiency. The real value for operations is to have an indication of excess oxygen available to operators, along with appropriate alarms so that corrective actions can be taken in a timely manner. Therefore, considering all of the above, it is recommended that the paragraph 63.7525(a)(2) wording be revised to read as follows (suggested inserts in italics):

(2) You must operate the oxygen analyzer *and trim* system with the oxygen level set at *or above* the minimum percent oxygen by volume that is established as the operating limit for oxygen according to Table 7 to this subpart *when firing the fuel or fuel mixture utilized during the most recent CO performance stack test. Operation of oxygen trim control systems to meet these requirements shall not be done in a manner which compromises furnace safety.*

Response: For a response to different oxygen settings and varied fuels, see comment EPA-HQ-OAR-2002-0058-3504-A1, excerpt 16.

While The EPA does not expect or intend for source operators to compromise the safety of their operations we do feel that the requirements of the rule are flexible enough to allow sources to determine and meet compliance levels without jeopardizing the safety of their employees or facilities. The affirmative defense section in the rule provides for extenuating operational circumstances that necessitate deviations from compliance limits.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 42

Comment: Solid or liquid fuel fired boilers and process heaters subject to the CO limits in this rule may also be equipped to fire other liquid or gas fuels that may be able to allow the unit to operate at lower oxygen levels for improved boiler efficiency. Alternatively, they may also fire

biomass or other traditional fuels that require higher excess air for improved combustion. Operators may also need to modify the oxygen setpoint or trim system to accommodate boiler or fuel quality issues. EPA needs to recognize that oxygen trim systems not only provide a means for energy efficiency, but they also are integral to furnace combustion control and furnace safety. While use of a 30-day rolling average does provide some operating latitude, this rule should not needlessly restrict operator latitude relative to safety or operating efficiency.

Response: For response to different oxygen settings and varied fuels, see comment EPA-HQ-OAR-2002-0058-3504-A1, excerpt 16.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 43

Comment: The real value for operations is to have an indication of excess oxygen available to operators, along with appropriate alarms so that corrective actions can be taken in a timely manner. Therefore, considering all of the above, ACC recommends that § 63.7525(a)(2) be revised to read as follows:

(2) You must operate the oxygen analyzer and trim system with the oxygen level set at or above the minimum percent oxygen by volume that is established as the operating limit for oxygen according to Table 7 to this subpart when firing the fuel or fuel mixture utilized during the most recent CO performance stack test. Operation of oxygen trim control systems to meet these requirements shall not be done in a manner which compromises furnace safety.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 71.

Commenter Name: Bart Sponsellar

Commenter Affiliation: Wisconsin Department of Natural Resources

Document Control Number: EPA-HQ-OAR-2002-0058-3527-A2

Comment Excerpt Number: 13

Comment: The Department believes that monitoring both CO and O₂ with a combustion analyzer system (non-CEM) is the best option for achieving complete and efficient combustion on a continuous basis. Sources under the state requirement have indicated that combustion efficiency is more sensitive to CO than to O₂ concentrations in the flue gas. Basically, monitoring O₂ levels help a source target combustion efficiency on the gross level while monitoring CO is used to fine tune pollutant levels and combustion efficiency. This finding is simply supported by looking at the magnitude of changes in concentration used in performing the trimming. Oxygen analyzer and trim systems are responding to changes on the order of 1% excess air or approximately 10,000 ppm O₂. Comparatively changes in CO are being monitored for combustion purposes between 10 to 500 ppm. Therefore a combustion efficiency system with both O₂ and CO monitoring will be able to achieve better performance than a system which monitors only O₂. The Department believes this approach to combustion trim systems ensures continuous and overall better control for all organic HAP emissions including dioxins and furans.

Therefore the Department supports EPA's approach to using an oxygen trim system for parametric monitoring along with annual stack testing. However, the Department believes that sources using a continuous automated combustion trim system with both CO and O₂ combustion analyzer monitoring should be allowed stack testing no more frequent than every two years. Similar to EPA's proposed PM continuous monitoring system (CMS), a CO and O₂ CMS can be maintained as a parametric monitoring system without the burden or expense of certification. A longer period between stack testing can potentially be allowed with a plan that ensures proper CO monitor calibration and operation of the trim system over time.

Response: The EPA thanks the commenter for their support of oxygen trim systems and annual stack testing.

The EPA makes no allowance other than annual stack testing requirements in the final rule.

Commenter Name: Bart Sponsellar

Commenter Affiliation: Wisconsin Department of Natural Resources

Document Control Number: EPA-HQ-OAR-2002-0058-3527-A2

Comment Excerpt Number: 27

Comment: For source categories that do not have emission limitations, such as oil and gas boilers or boilers smaller than 10 mmBtu/hr, the MACT rule requires that tune-ups be performed every two years. These sources should have the alternative to install and operate a CO/O₂ CMS trim system with tune-ups conducted on a four year schedule. This provides the same alternative as proposed for the larger sources subject to emission limitations.

Response: For a response to request for an alternative joint O₂ and CO monitoring option for all sources, please see comment EPA-HQ-OAR-2002-0058-3527-A2, excerpt 13.

The EPA disagrees with the commenter in that a unit less than 10 Mmbtu/hr may employ an O₂ trim system, but is still subject to the biennial tune-up requirement of the rule.

11C01. PM CPMS: Specifications/Operations

Commenter Name: Dakota Gasification Company Great Plains Synfuels Plant

Commenter Affiliation: David W. Peightal

Document Control Number: EPA-HQ-OAR-2002-0058-3424

Comment Excerpt Number: 6

Comment: DGC agrees with EPA's comment on the PM CEMS lack of appropriate representation of data to demonstrate continuous compliance and agrees on the use of parameter monitors as an alternate method of continuous demonstration of compliance with the emissions limits. DGC's current Title V CAM Plan addresses an opacity correlation to our PM emissions limit, thus DGC would like to continue use of this approved parametric approach to show continuous compliance with the PM emission limits [See Attachment 2 of the submittal for the DGC Title V CAM Plan.]

Response: The EPA thanks the commenter for their support. Also, if the commenter is proposing to use their CAM plan as an alternative monitoring procedure, please refer to 40 CFR 63.8(f) for methodology for submitting the proposal for review.

Commenter Name: Gary Melow, Director

Commenter Affiliation: Michigan Biomass (MB)

Document Control Number: EPA-HQ-OAR-2002-0058-3478-A1

Comment Excerpt Number: 3

Comment: We strongly support removal of continuous emission monitors (CEMs) for particulate matter for biomass. Our continuous opacity monitors and proper operation of our control equipment assures very low particulate emissions.

Response: The EPA thanks the commenter for their support.

Commenter Name: Lee Zeugin and Lauren Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1

Comment Excerpt Number: 25

Comment: Under the 2011 final rule, units with a heat input rate greater than 250 MMBtu/hr from solid fuel and/or residual oil must install a particulate matter (“PM”) continuous emissions monitoring system (“CEMS”) to demonstrate compliance. 40 C.F.R. §§ 63.7510(d), 63.7525(b). In comments on the 2010 proposed rule, UARG objected to this requirement, pointing to EPA’s failure to consider the ability of PM CEMS to meet the required Performance Specification 11 (“PS 11”) criteria, or to accurately measure PM, at the levels of the proposed standards. EPAHQ-OAR-2002-0058-2880.1 at 51-54. Because EPA did not fully address or respond to UARG’s comments, UARG included the issue in its reconsideration petition. EPA-HQ-OAR-2002-0058-3324 at 16-17.

On reconsideration, EPA acknowledges commenters’ concerns regarding application of PM CEMS technology to various types of IBs, and concludes that for coal- and oil-fired IBs PM CEMS would best be employed as parametric monitors (*i.e.*, as a PM continuous parameter monitoring system or “PM CPMS”).¹⁴ 76 Fed. Reg. at 80,610/1. Under EPA’s new proposal, sources would be required to install and operate a PM CEMS, but would not be required to meet PS 11. Instead, sources would be required to establish during initial and periodic performance tests a site-specific operating limit in terms of the PM CPMS output, and to meet that operating limit on a 30-day rolling average basis. Proposed §§ 63.7510(d), 63.7525(b), and Table 8.

UARG appreciates EPA’s acknowledgment of the issues using PM CEMS under the final rule and supports EPA’s proposal to use the monitors as PM CPMS rather than to demonstrate compliance with an emission limit.

[Footnote]

(14) EPA also proposes to add an alternative total selected metals limit, which could be met using performance stack tests and operating parameters rather than PM CEMS. UARG supports addition of this option.

Response: The EPA thanks the commenter for their support.

Commenter Name: Stephen E. Woock

Commenter Affiliation: Weyerhaeuser Company

Document Control Number: EPA-HQ-OAR-2002-0058-3523-A1

Comment Excerpt Number: 17

Comment: We support EPA's decision to propose removing use of PM CEMS where previously required for solid fuel units with >250 mmBtu/hour heat input in the March 2011 final rule. EPA has recognized PM CEMS are not proven for the uses it was assigning them. In particular, the quality of biomass fuels can change from day to day and even hour to hour, depending on market source and availability. Mills often burn a mixture of fuels (green versus dry, top of the pile versus bottom of the pile, hardwood residuals versus softwood residuals, bark versus wood, etc.), and most often the fuels are not blended. In some cases, biomass is co-fired with fossil fuels. The reliability of PM CEMS and the ability to establish appropriate correlation curves across fuel types for these CEMS under constantly changing fuel conditions has not been demonstrated, thus EPA's requirement was unreasonable.

Response: The EPA thanks the commenter for their support.

Commenter Name: Heather Parent

Commenter Affiliation: Maine Department of Environmental Protection

Document Control Number: EPA-HQ-OAR-2002-0058-3691-A2

Comment Excerpt Number: 16

Comment: Maine DEP supports EPA's removal of the requirement to install a PM CPMS on biomass fired units.

Response: The EPA thanks the commenter for their support.

Commenter Name: Cheryl Suttman

Commenter Affiliation: Ohio EPA, Division of Air Pollution Control

Document Control Number: EPA-HQ-OAR-2002-0058-3795-A1

Comment Excerpt Number: 7

Comment: If using PM CEMS, can we (State EPA) require certification w/ SP 11 for the demonstration of compliance for PM, following the initial performance test using PS 11 concurrently with Method 5 or 17? Or, can we suggest that PM CEMS, certified in accordance w/ PS 11, be identified at an option under §63.7525(b)(1) for compliance.

Response: The EPA has modified the rule language to reflect three compliance options. A source may either install PM CEMS according to §63.7525(b)(5), install PM CPMS according to §63.7525(b)(1), or conduct emissions testing on a quarterly basis.

Commenter Name: Vickie Woods

Commenter Affiliation: Division of Air Quality, North Carolina Department of Environment and Natural Resources (NCDENR)

Document Control Number: EPA-HQ-OAR-2002-0058-3663-A2

Comment Excerpt Number: 9

Comment: PM. Allow PM CEMS as alternative, rather than requirement; revising requirement to be continuous parameter monitoring on a 30-day rolling average similar to EGU MACTs.

NC DAQ concurs with EPA's proposed approach on this issue.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3795-A1, excerpt 7.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 46

Comment: Beyond the objection to the practicality and cost of PM CPMS on these types of boilers, ACC is concerned about the requirement to limit the 30-day rolling average PM CPMS output data (milliamperes) to less than the operating limit established during the performance test (see Table 8, item 2c). As discussed below, ACC believes this requirement is unreasonable and would reduce operating flexibility of these boilers to an untenable level.

First, it imposes a much tighter operating envelope than even the final rule, which only required the 30-day rolling average to remain less than the emission standard (see § 63.7525(b)(3) of the Final Boiler Rule). At the very least, if EPA were to require these monitoring systems, they should allow the operating limit to be increased by the ratio of the allowable PM emission rate to the actual PM emission rate during the performance test.

Second, it does not account for variation in the measurement device output that is likely to occur during long-term operation. The fact that the measurement system is not held to some defined reference method will add to the uncertainty of the data. Even if it were held to PS-11, those specifications include a correlation coefficient of 0.85 between measured and predicted stack gas PM concentrations and the systems will have a high error band compared to the actual PM emission levels and indicate non-compliance when that is often not the case.

Response: The EPA recognizes that a source operating in continuous compliance is operating below their emissions limit at all times, and we therefore disagree with the commenter that use of PM CPMS reduces operating flexibility under this rule. The source operating parameter is tied to the average hourly output during a compliance test. This number is then used as a 30 day rolling average to allow for operational variability and flexibility as well as variation in the measurement device. While this operating level is, by definition, below the emissions limit of the rule, it is source specific and is expected to allow a well operated source the necessary flexibility to conduct normal operations and maintain compliance with the rule at all times. Allowing sources to exceed this value consistent with a ratio of allowable PM emissions is not technically possible as the instrument is not calibrated along a scale of PM emissions. Values

above and below the established operating limit are not measurements of PM concentration values, per se, but rather an indicator of PM concentration change. The rule does allow flexibility to use PM CEMS for continuous PM compliance should a source wish to measure PM continuously and use the full range of their PM emissions limit.

Commenter Name: Lee Zeugin and Lauren Freeman
Commenter Affiliation: Utility Air Regulatory Group (UARG)
Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1
Comment Excerpt Number: 26

Comment: EPA's proposal to impose an enforceable site-specific operating limit based on output during a single short-term stack test remains flawed. A three-run performance test will not capture the variability in PM CPMS output that may occur during operations consistent with the PM limit, and setting a limit based on such a test will put sources at an unreasonable risk of noncompliance without any evidence that the PM limit has been exceeded. Although the proposed 30-day averaging period will add some flexibility, UARG is concerned it will not be sufficient and EPA has provided no data to suggest that it will be.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 46.

Commenter Name: David A. Buff, Golder Associates Inc.
Commenter Affiliation: Florida Sugar Industry (FSI)
Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1
Comment Excerpt Number: 24

Comment: While the FSI supports EPA's proposal to give an affected source the option of using PM monitoring technology as a parametric monitor, which could be used to demonstrate compliance with operating limits, rather than emission limits, the FSI has some concerns over this approach. See 76 F.R. 80610; see also Section 63.7525(b) at 76 F.R. 80637. If a source must use, or chooses the option of using, a PM continuous parameter monitoring system (CPMS), the operating limit should be set at a level that is equivalent to the PM limit for the boiler, not at the PM emission rate experienced during the 3-run performance testing. The output of the PM CPMS must be expressed in milliamps, stack concentration, or other raw data signal. However, this raw data signal can be calibrated and/or correlated to the PM emissions during the testing. If the operating limit is set at the emission rate experienced during the performance testing, this is essentially setting a lower PM standard for that boiler.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 46.

Commenter Name: Melvin E. Keener
Commenter Affiliation: Coalition for Responsible Waste Incineration (CRWI)
Document Control Number: EPA-HQ-OAR-2002-0058-3454-A1
Comment Excerpt Number: 16

Comment: It is also unreasonable to limit the 30-day rolling average PM CPMS output data (milliamps) to less than the operating limit established during the performance test (see Table 8,

item 2c). This requirement would reduce operating flexibility of these boilers to an unacceptable level. It imposes a much tighter operating envelope than even the final rule, which only required the 30 day rolling average to remain less than the emission standard (see §63.7525(b)(3) of the March 21, 2011 final rule). At the very least, EPA should allow the operating limit to be increased by the ratio of the allowable PM emission rate to the actual PM emission rate during the performance test.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 46.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 98

Comment: Beyond an overall objection to the practicality and cost of using PM CPMS on these types of boilers is the unreasonable requirement to limit the 30-day rolling average PM CPMS output data (milliamps) to less than the operating limit established during the performance test (see Table 8, item 2c). This requirement would reduce the operating flexibility of these boilers to an untenable level. First, it imposes a much tighter operating envelope than even the final rule, which only required the average PM CEMS output in lb/MMBtu to remain less than the emission standard (see §63.7525(b)(3) of the March 21, 2011 final rule). Second, it does not account for variation in the measurement device output that is likely to occur during long-term operation, especially with changes in fuel characteristics/fuel mix.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 46.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 99

Comment: Even if an installed PM monitor were held to PS-11, those specifications include a correlation coefficient of 0.85 between measured and predicted stack gas PM concentrations and the systems will have a high error band compared to the actual PM emission levels and indicate non-compliance when that is often not the case. If these monitors are retained as parametric monitors in the final rule, EPA should not require sources to "certify" them and should allow operation at a signal level that is adjusted according to the unit's compliance margin with the applicable PM limit.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 46.

Commenter Name: Steve Gossett

Commenter Affiliation: Eastman Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3669-A2

Comment Excerpt Number: 19

Comment: Beyond this overall objection to the practicality and cost of PM CPMS on these types of boilers is the unreasonable requirement to limit the 30-day rolling average PM CPMS output data (milliamps) to less than the operating limit established during the performance test (*see* Table 8, item 2c). This requirement would reduce operating flexibility of these boilers to an untenable level. First, it imposes a much tighter operating envelope than even the final rule, which only required the 30 day rolling average to remain less than the emission standard (*see* §63.7525(b)(3) of the March 21, 2011 final rule). At the very least, if EPA were to require these monitoring systems, they should allow the operating limit to be increased by the ratio of the allowable PM emission rate to the actual PM emission rate during the performance test. Second, it does not account for variation in the measurement device output that is likely to occur during long-term operation. The fact that the measurement system is not held to some defined reference method will add to the uncertainty of the data. Even if it were held to PS-11, those specifications include a correlation coefficient of 0.85 between measured and predicted stack gas PM concentrations and the systems will have a high error band compared to the actual PM emission levels and indicate non-compliance when that is often not the case.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 46.

Commenter Name: Lee Zeugin and Lauren Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1

Comment Excerpt Number: 28

Comment: Rather than use the PM CPMS output to set a not be exceeded limit, EPA should rely on the approach taken in the Compliance Assurance Monitoring (“CAM”) rule under Part 64 and require sources to establish a site-specific operating parameter baseline above which the owner or operator must investigate and, if necessary, take corrective action. This approach already has been upheld as sufficient to satisfy the CAA’s requirements for demonstrating continuous compliance. *See NRDC v. EPA*, 194 F.3d 130, 135-37 (D.C. Cir. 1999) (rejecting NRDC’s argument that the CAM rule’s “reasonable assurance of compliance” is not sufficient to assure continuous compliance as required by the CAA). EPA has taken a similar approach in at least one New Sources Performance Standard (“NSPS”) where the combination of controls makes monitoring compliance using traditional methods unreasonable. *See, e.g.*, 40 C.F.R.

§ 60.48Da(o)(2) (requiring establishment of a 24-hour average opacity baseline above which appropriate action is required). Such an approach would ensure that controls are operated consistent with the applicable PM limit without imposing unnecessary and unreasonable risk of noncompliance.

Response: The EPA agrees with the commenter and has revised the rule language to reflect this approach.

Commenter Name: Mary Sullivan Douglas

Commenter Affiliation: National Association of Clean Air Agencies (NACAA)

Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1

Comment Excerpt Number: 56

Comment: EPA has proposed to delete the requirement that compliance monitors for PM limits conduct annual RATA testing to demonstrate the accuracy of the results. NACAA opposes this proposal as it will diminish the protectiveness of the standards and potentially render the standard unenforceable.

Response: The EPA disagrees with the commenter in that we have retained PM CEMS compliance options that use PS-11 RATA testing in the rule. We have also included continuous PM compliance with PM CPMS monitoring using reference method stack testing to prove compliance with the rule and establish 30-day rolling average operating limits. We consider that both of these approaches will provide equivalent protection and compliance with the standard under the rule.

Commenter Name: Bart Sponsellar

Commenter Affiliation: Wisconsin Department of Natural Resources

Document Control Number: EPA-HQ-OAR-2002-0058-3527-A2

Comment Excerpt Number: 14

Comment: Under the MACT rule certain sources were required to continuously monitor particulate emissions using a certified continuous emissions monitoring system (CEMs). EPA is now proposing that this requirement be replaced by a continuous particulate monitoring which is calibrated according to accurately measure emissions but which is not subject to the rigorous CEMs certification requirements and cost. Basically, the particulate monitoring is implemented as a parametric monitoring system. The Department supports EPA's approach to minimizing continuous monitoring requirements from a PM CEMS to a non-certified PM continuous monitoring system (PM CMS). The Department further believes that with direct PM CMS a source should only be required to stack test particulate every two years. This is especially true if the source is performing parametric monitoring of an activated carbon injection system which positively controls both mercury and non-mercury metals. In place of PM CMS monitoring we believe it is sufficient for a source to stack test annually then we believe parametric monitoring of ESP or fabric filter systems is sufficient. We believe a source should be provided the alternative of a PM CMS with biennial stack testing or parametric monitoring of particulate control devices along with annual stack testing. The Department believes that a source should be subject to biennial stack testing instead of annual stack testing when the pollutant is continuously monitored by a CMS or parametric monitoring of control equipment which positively reduces emissions of the pollutant in question (metals, mercury, CO) for a pollutant which has been demonstrated by the source to correlate with the pollutant in question.

Response: The EPA thanks the commenter for their support of using PM CPMS, but disagrees with the commenter that biannual testing is sufficient for setting and validating the operating parameter. An annual compliance test is necessary to update the parametric monitor with new information about the PM emissions as related to differences in fuel and control device operations over time.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 85

Comment: PM CEMS have not been demonstrated for use on biomass or on other installations where fuel type, production rate or other characteristics of the emissions are changing. CIBO appreciates the fact that EPA recognizes that PM CEMS cannot effectively be used to measure particulate emissions accurately. However, EPA is proposing use of this instrument as a PM CPMS. However, for the same reasons that a PM CEMS is not practical for use in measuring PM, the PM CPMS will not provide any meaningful correlation to emissions or control device effectiveness and therefore is a technically inappropriate choice. In addition to the fact that a PM CPMS will not correlate with emissions and cannot be used effectively in a PM CPMS, it is much more costly than devices that can perform the same function. Thus, EPA must abandon its proposal to require PM CEMS technology for a PM CPMS.

Response: The EPA disagrees with the commenter that PM CPMS cannot be used effectively to monitor emissions continuously. The EPA has a long history of using continuous parametric monitoring in a wide variety of rules and has found the use of such monitoring to be effective in reducing source emissions through improving operational control monitoring..

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 91

Comment: For the same reasons that it is not feasible to develop a meaningful correlation between the emissions being monitored by the PM CEMS instrument and particulate emissions in the stack, using the PM CEMS instrument technology as a PM CPMS will produce no repeatable and no meaningful results in situations where the characteristics of the stack emissions change due to changes in fuel mixtures, production rates and instrument correlation issues.

The output from a PM CPMS based on a PM CEMS instrument will simply be meaningless. Any time the fuel mixture changes, the instrument will go out of range even with no change to control device effectiveness or any meaningful change to emissions. This means that requiring use of a PM CPMS would be a very expensive waste of capital resources and would send both the regulated industry and the regulatory agencies on meaningless goose chases. Put quite simply, this technology will not work for its intended purposes.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 85.

Commenter Name: Pat Dennis

Commenter Affiliation: Archer Daniels Midland Company

Document Control Number: EPA-HQ-OAR-2002-0058-3670-A2

Comment Excerpt Number: 14

Comment: PM CEMS have not been demonstrated for use on biomass or on other installations where fuel type, production rate or other characteristics of the emissions are changing. ADM's

locations may use as many as 7 different sources of coal in addition to TDF and wood. CIBO appreciates the fact that EPA recognizes that PM CEMS cannot effectively be used to measure particulate emissions accurately. However, EPA is proposing use of this instrument as a PM CPMS. For the same reasons that a PM CEMS is not practical for use in measuring PM, the PM CPMS will not provide any meaningful correlation to emissions or control device effectiveness and therefore is a technically inappropriate choice. In addition to the fact that a PM CPMS will not correlate with emissions and cannot be used effectively in a PM CPMS, it is much more costly than devices that can perform the same function. Thus, EPA must abandon its proposal to require PM CEMS technology for a PM CPMS.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 85.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 87

Comment: In the proposed Reconsidered Rule, PM CPMS has replaced the requirement of a PM CEMS. CPMS is not optional for sources >250 MMBtu. Although EPA altered the monitoring requirement, it is still onerous and not necessary to demonstrate compliance. The CPMS equipment is the same as the prior CEMS requirement, which is a major capital installation not justified by any additional environmental or compliance benefit beyond other PM monitoring systems.

The PM limits for solid fuel boilers range from 0.028 lbs/mmbtu for stoker boilers to 0.088 lbs/mmbtu for fluidized bed boilers. Almost all fluidized bed boilers in the country have been permitted since the effective date of the 40 CFR Part 60 Subpart Db NSPS and will have allowable limits for PM no higher than 0.05 lbs/mmbtu. Also, since most new solid fuel boilers would also have been permitted under PSD or non-attainment NSR, their allowable limits are likely more in the range of 0.02 – 0.03 lbs/mmbtu. As such, COMs supplemented with bag leak detectors and pressure drop monitoring are perfectly adequate to prevent any exceedance of the existing allowable standards much less, the 0.088 lbs/mmbtu proposed for the MACT. The addition of a CPMS will be a needless expense and will offer no benefit. Likewise, stoker and PC boilers can be, and are in practice, adequately monitored by COMs and parametric monitoring.

Response: The EPA believes a PM CPMS can produce data indicative of trends and changes in emissions, as well as be effective in monitoring control device performance. Additionally, the final rule now allows most boilers options when measuring PM. For instance, boilers with an average heat input greater than 250 MMBtu/hr, that burn coal or liquid/gas for fuel, have the option of using either PM CEMS or PM CPMS. Boilers with an average heat input of less than or equal to 250 MMBtu/hr have the option to measure PM with a PM CEMS, a PM CPMS, or to conduct periodic testing, regardless of fuel. If a source feels that one option is not suitable or practical for their unit, then the source is encouraged to select the option most applicable to their specific site. COMS and other CPMS are optional for units below 250 MMBtu.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1
Comment Excerpt Number: 92

Comment: PM CEMS are not technically effective across a range of conditions as discussed above and are a very expensive method for achieving EPA's objective of assuring ongoing compliance with Boiler MACT and CISWI requirements. Costs¹⁸ for the light scattering PM CEMS, which is lower operating and maintenance costs vs the Beta Attenuation technology was estimated by EPA contractor data to cost between \$103,000 to 133,000 in 2004, with substantial annual operating costs as shown below. [See submittal for Table 3]

The above costs are high in and of itself. However, these costs do not include what might be required to establish correlation curves for multiple fuel and work to try to find a way to make this technology work effectively in scenarios it has never been successfully applied. Given the range of fuels, production rates and other variables in a given installation that would have to be accounted for, this cost is believed to be a small fraction of the true cost for applying this technology.

There are much more effective tried and true technologies that are currently used for assuring compliance that have been demonstrated to be effective in a variety of situations. For example, bag leak detection systems, baghouse pressure drop and many other technologies which EPA has included in their Compliance Assurance Monitoring Guidance would be much more effective and accurate indicators of problems with control technology. These tried and true and less costly approaches should be adopted to assure compliance. EPA should not force industry to use an unproven technology which is unlikely to be effective in a variety of situations when a simpler more elegant technological solution is already at hand.

For the above reasons, EPA must abandon its proposal to use PM CPMS as an indicator of effective operation.

[Footnote 18: Status of Particulate Matter Continuous Emission Monitoring Systems for Application to Electric Utility Steam Generating Units, Prepared for: Emission Standards Division Office of Air Quality Planning and Standards U.S. Environmental Protection Agency, September 7, 2004

Response: See the response to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 87.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1
Comment Excerpt Number: 93

Comment: As an alternative to the extremely expensive particulate matter CEMS installation EPA proposes, EPA should allow the installation and operation of bag leak detection systems in accordance with the proposed rule's §63.7525(j)(1) through (8) in addition to the existing opacity monitors and pressure drop monitoring. The bag leak detection system provides ongoing

monitoring of the bag house component performance and provides for continuous compliance demonstration.

Method 5 stack testing is performed at the rated capacity of the boiler. At this rated capacity, all systems for particulate control are maximized as well (e.g., the air/cloth ratio in the baghouse, the ID fan output, ductwork losses, etc.). Hence, for particulate matter, stack testing conditions are the worst case operating conditions. At lower loads, the basic design parameters for the particulate collection system and for the combustion air management are not as taxed so it would be reasonable to expect that at lower loads, particulate emissions on a lb/MMBTU basis would be lower than the stack test. If all systems that were operating during the stack test continue to operate properly during normal operation, continuous compliance with the stack test can be determined due to the nature of particulate matter emissions behavior. One CIBO member already operates and maintains PS1 certified opacity monitors on all three units as well as monitoring baghouse pressure drop.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 87.

Commenter Name: Steve Gossett

Commenter Affiliation: Eastman Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3669-A2

Comment Excerpt Number: 18

Comment: Eastman has seven coal fired boilers at its Tennessee Operations (TNO) that are larger than 250 MMBtu/hr. These seven units, which range in size from 65 MWe to 88 MWe (electrical equivalent basis), are significantly smaller than a typical EGU and would have a commensurately smaller impact on the environment and human health. Eastman's 2011 engineering analysis of MACT control technologies for its fleet at TNO included estimating the cost of installing PM CEMS on its larger coal fired boilers. Based on budgetary quotations for SICK Maihak FWE 200 monitors and the estimated cost to install them on these seven units, the total installed cost was estimated at \$2.25 million. In addition to the capital cost, Eastman further estimated that the labor to maintain the instruments, provide quality assurance of the data, and coordinate stack testing would exceed \$100,000 per year. Eastman believes the state of Tennessee would, in absence of any guidance from EPA to the contrary, refer to PS-11 for certification given that this test method is the only accepted reference method. The cost of mobilizing a third-party testing firm to conduct a certification test would easily exceed \$30,000 per event, in addition to the internal labor required to support such testing. Given these significant capital and ongoing costs, and considering how much smaller Eastman's seven units are compared to a typical EGU, Eastman believes the requirement to install a PM CPMS to be unreasonably burdensome.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 87.

Commenter Name: Steve Gossett

Commenter Affiliation: Eastman Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3669-A2

Comment Excerpt Number: 20

Comment: Finally, if EPA is concerned that some method of parametric monitoring is necessary to ensure that sources adopt good practices to operate and maintain their particulate collectors, any number of lower cost alternatives exist to mandating the use of expensive particulate monitors. Most obviously, sources can use opacity monitoring systems, as has been the practice across many industries for decades. Units equipped with precipitators can monitor total power (e.g. based on secondary voltage and current), limits for which could be established during a performance test where the source successfully complies with the PM standard applicable for the unit. Units with fabric filters should be offered the flexibility to use bag leak detection systems, monitoring of cleaning cycles, or compartment pressure drop in lieu of a PM CPMS, which would provide real-time feedback of the performance of the FF at a fraction of the cost. Given that alternative methods to produce real-time monitoring and feedback of the PM collector efficiency exist, and at dramatically lower costs than PM CPMS or PM CEMS, EPA should give sources the flexibility to comply using less expensive and burdensome technologies.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 87

Commenter Name: Pat Dennis

Commenter Affiliation: Archer Daniels Midland Company

Document Control Number: EPA-HQ-OAR-2002-0058-3670-A2

Comment Excerpt Number: 15

Comment: The PM limits for solid fuel boilers range from 0.028 lbs/mmbtu for stoker boilers to 0.088 lbs/mmbtu for fluidized bed boilers. Almost all fluidized bed boilers in the country have been permitted since the effective date of the 40 CFR Part 60 Subpart Db NSPS and will have allowable limits for PM no higher than 0.05 lbs/mmbtu. Also, since most new solid fuel boilers would also have been permitted under PSD or non-attainment NSR, their allowable limits are likely more in the range of 0.02 - 0.03 lbs/mmbtu. As such, COMs supplemented with bag leak detectors and pressure drop monitoring are perfectly adequate to prevent any exceedance of the existing allowable standards much less, the 0.088 lbs/mmbtu proposed for the MACT. This fact is evidenced by the 20 or more years of acceptable compliance monitoring by the community of fluidized bed boilers. The addition of a CPMS will be a needless expense and will offer no benefit. Likewise, stoker and PC boilers can be, and are in practice, adequately monitored by COMs and parametric monitoring.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 87.

Commenter Name: Douglas A. McWilliams

Commenter Affiliation: American Municipal Power

Document Control Number: EPA-HQ-OAR-2002-0058-3685-A2

Comment Excerpt Number: 43

Comment: This arbitrary decision to require PM CPMS for coal- and oil-fired units >250 mmBtu/hr is particularly problematic considering that these units already employ continuous monitoring devices to comply with the Compliance Assurance Monitoring ("CAM") provisions of 40 C.F.R. § 64. AMP's municipal utilities are also required to have continuous opacity monitoring ("COM") systems that monitor PM control device performance. COMs monitor particulate matter in flue gas streams by sending a beam of light through the flue gas and

measuring the attenuation caused by particles in the flue gas. Certain PM CEMs use a similar light absorption technique, or other optical techniques, to generate PM readings.⁴³ PM CPMS also use principles of light scatter to monitor PM emissions.⁴⁴ EPA has relied on COMs readings, combined with periodic stack testing, to monitor compliance with PM limits for decades. EPA also proposes to rely on these readings to ensure continuous compliance with the Boiler MACT requirements for units not subject to the PM CPMS requirement. Regulated units have already installed this equipment and are familiar with its maintenance and operation. Requiring a PM CPMS, in addition to COMs that are already installed and relied upon by the Agency, in addition to annual PM stack testing, is arbitrary and unreasonable and places an unnecessary burden on municipal utilities without any environmental benefit.

[Footnote 43: Electric Power Research Institute, Status of Particulate Matter Continuous Emission Monitoring Systems 2-1 (Mar. 2006).]

[Footnote 44: 76 Fed. Reg. at 80603.]

Response: See the response to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 87.

Commenter Name: Randall D. Quintrell

Commenter Affiliation: Georgia Paper & Forest Products Association

Document Control Number: EPA-HQ-OAR-2002-0058-3451-A1

Comment Excerpt Number: 14

Comment: The elimination of PM CEMS as a direct measure of compliance is appropriate and necessary. As stated in our prior comments, the PM CEMS is an unproven technology for use on industrial boilers. It is particularly unsuited to biomass boilers and multifuel boilers, and we support EPA's recognition of these facts. However, as noted above, the proposed use of PM CEMS for parametric monitoring is also inappropriate for industrial boilers and is unjustifiably burdensome and costly. The reasons such data are unreliable and inappropriate for use as a direct measure are the same reasons it is unreliable and inappropriate for parametric monitoring.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 87.

Commenter Name: Douglas A. McWilliams

Commenter Affiliation: American Municipal Power

Document Control Number: EPA-HQ-OAR-2002-0058-3685-A2

Comment Excerpt Number: 42

Comment: However, AMP does not support EPA's replacement of the PM CEM obligation with a PM CPMS obligation for coal- and oil-fired units of this size. Requiring a PM CPMS in lieu of a PM CEM does not resolve any of the issues pointed out by petitioners in prior comments.

EPA has offered no justification for requiring any type of additional PM monitoring for coal- and oil-fired units greater than 250 mmBtu/hr. All other units are subject to less burdensome operating limits (such as opacity limits, bag leak detection requirements, and primary and secondary voltage requirements), and have the option to use PM CPMS in lieu of these other

monitors. EPA has determined that these other monitoring parameters are sufficient to ensure continuous compliance with the emission limits. There is no justification for requiring the installation of an additional, expensive monitor for coal - and oil-fired units >250 mmBtu/hr when there is no evidence that the monitoring requirements applicable to other units are insufficient for units of this size. Because EPA can articulate no rationale for making PM CPMS optional for some units and mandatory for others, this requirement is arbitrary and should be eliminated. Instead, installation of a PM CPMS should be optional for all units in the final rule.

Response: The EPA agrees and has modified the rule to allow PM CPMS for continuous PM emissions compliance for all affected units.

Commenter Name: Robin Mills Ridgway

Commenter Affiliation: Purdue University

Document Control Number: EPA-HQ-OAR-2002-0058-3668-A2

Comment Excerpt Number: 2

Comment: Purdue asks EPA to confirm that only boilers having an average annual heat input of greater than 250 MMTU/hr need to install a PM CPMS for particulate throughout the repropose rule (e.g., §63.7510(d)). In §63.7575, EPA defines average annual heat input as the annual heat input divided by the number of operating hours for the year preceding the compliance determination. Purdue suggests that this value be determined not from the preceding year, but by using three consecutive years beginning **after** the compliance date to determine average annual heat input. As Purdue experienced during construction work for Boiler MACT I (2004), operating hours in the years preceding the compliance date may not be typical of normal operations due to MACT compliance construction activities.

Response: The final rule requires units combusting solid fossil fuel or heavy liquid with heat input capacities of 250 MMBtu/hr or greater to install, certify, maintain, and operate particulate matter (PM) continuous parameter monitoring systems (CPMS). Moreover, owners or operators of units combusting solid fossil fuel or heavy liquid with heat input capacities of 250 MMBtu/hr or greater are allowed to install, certify, maintain, and operate PM CEMS as an alternative to the use of PM CPMS, since similarly-sized commercial and industrial solid waste incinerators (CISWI) units and electrical generating units (EGUs) subject to the mercury air toxics standards (MATS) are able to use PM CEMS as an alternative to PM CPMS. Just as units using PM CPMS will not be required to conduct parameter monitoring for PM, units using PM CEMS will not be required to conduct parameter monitoring for PM.

Commenter Name: Steve Gossett

Commenter Affiliation: Eastman Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3669-A2

Comment Excerpt Number: 47

Comment: Issue #2: EPA is clarifying that emissions averaging cannot include units using a CEMS or PM CPMS.

Comment Summary: Units using CEMS for compliance should be allowed to utilize the emissions averaging provisions for compliance with no discount factor applied.

In Section 63.7522(b)(1), EPA added and is taking comment on a new provision stating "You may not include in an average units using a CEMS or PM CEMS for demonstrating compliance, even if the use of a CEMS or PM CEMS is optional."

EPA is proposing this restriction on use of CEMS for emissions averaging without explaining the basis for the restriction. Moreover, this restriction is in direct conflict with the emissions averaging provisions in the Utility MACT (§63.10009). EPA should provide industrial and institutional facilities at least the same flexibility it provides electric utilities. This restriction would discourage the use of CEMS (where they are optional) in cases where a source elects to utilize emissions averaging. EPA should encourage use of CEMS, which provide a much more accurate estimate of actual emissions than periodic emissions tests. We see no valid reason for such restriction and request that the emissions averaging provisions be revised similar to the Utility MACT, to accommodate use of CEMS or sorbent traps.

Response: The EPA agrees with the commenter and has revised the rule to allow emissions averaging for facilities using CEMS to demonstrate compliance.

Commenter Name: Cheryl Suttman

Commenter Affiliation: Ohio EPA, Division of Air Pollution Control

Document Control Number: EPA-HQ-OAR-2002-0058-3795-A1

Comment Excerpt Number: 5

Comment: PM CEMS were removed from the previous version of the boiler MACT. Can PM CEMS and Performance Specification 11 (e.g. a method of compliance in NSPS Subparts Da and Db) still be used to demonstrate compliance with the PM standards in Subpart DDDDD? Losing the option or requirement to use PM CEMS and Performance Specification 11 (PS 11) for certification was unexpected.

Or are PM CEMS simply a type of PM CPMS and the proposed amendment is allowing for other types of PM monitoring devices?

Response: The EPA is including PM CEMS calibrated and certified with PS-11 as a compliance option in the final rule.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 44

Comment: *PM CEMS*

EPA is proposing to employ PM CPMS rather than emissions compliance monitoring (CEMS). This proposal places sources in an untenable position if they are required to install, certify, and operate these monitoring systems. While EPA states these monitors do not have to comply with Performance Specification 11, presumably to reduce compliance burden, , EPA's proposed rule language requires the same host of requirements in a site-specific monitoring plan as any other continuous monitoring system (see § 63.7540(a)(9) and § 63.7505(d)).

ACC is not clear on how a source should "certify" their PM CPMS other than through the use of PS-11. EPA apparently recognizes that the burden of complying with PS-11 is unreasonable for coal-fired ICI boilers as it states in the 2010 Proposed Boiler Rule preamble at p. 80610. While EPA has required PM CEMS in the final MATS, those boilers are many times larger than ICI boilers with commensurately larger PM emissions and associated impact. They also operate at relatively steady loads compared to ICI boilers that have to respond to frequent load swings. ACC requests EPA remove from the final rule the requirement to install PM CPMS monitoring for boilers larger than 250 MMBtu/hr. Before requiring such a substantial monitoring burden on ICI sources, EPA should further evaluate these systems via field studies to determine the real-world performance.

Response: The final rule requires the source to develop a site specific monitoring plan (SSMP) for all continuous monitoring systems, including a PM CPMS. In the case of a PM CPMS, the monitor is used as a parametric monitor and not an emissions monitor and the source is allowed to determine the performance acceptance criteria and performance evaluation procedures that are appropriate for their specific stack conditions and process operations. Then the source conducts the performance evaluation as per the site specific monitoring plan. The SSMP does not require that PS 11 be used for the performance evaluation. Other methods to evaluate the performance of CPMS are available. For example, audit materials, vendor laboratory testing, etc. could be reasonable methods. Operation, maintenance, and QA/QC procedures are also developed specifically for each site. All of these requirements may be less rigorous than those for PM CEMS and are custom designed to be appropriate and practical for the site's own conditions.

The EPA has recently issued a memo on the capabilities of PM CEMS. That memo from Connie Oldham to Bob Schell, dated June 13, 2012, states that developing an acceptable PM CEMS correlation on a unit with very low emissions, or that burns multiple fuels, is possible but requires special care. For instance, one must select the best technology available for the job. The EPA has reviewed the study conducted by Georgia-Pacific and NCASI and would like to point out that the GP testing was done using only light scattering, or "backscattering" technology. If a source owner is concerned about the ability of a light based PM CEMS to meet the requirements of PS 11 because of variable physical characteristics of particles in the stack, there is at least one other PM CEMS technology based more directly on mass measurement rather than on the light scatter or "backscattering" technology.

Technical limitations of PM CEMS for a specific site do not mean that the technology cannot be used to monitor for compliance. The EPA believes a PM CPMS can produce data indicative of trends and changes in emissions, as well as be effective in monitoring control device performance. Additionally, the final rule now allows most boilers options when measuring PM. For instance, ERUs with an average heat input greater than 250 MMBtu/hr, that burn coal or liquid/gas for fuel, have the option of using either PM CEMS or PM CPMS. (However, large boilers that burn biomass are required to install PM CPMS.) Boilers with an average heat input of less than or equal to 250 MMBtu/hr have the option to measure PM with a PM CEMS, a PM CPMS, or to conduct periodic testing, regardless of fuel. If a source feels that one option is not suitable or practical for their unit, then the source is encouraged to select the option most applicable to their specific site.

Commenter Name: Cheryl Suttman
Commenter Affiliation: Ohio EPA, Division of Air Pollution Control
Document Control Number: EPA-HQ-OAR-2002-0058-3795-A1
Comment Excerpt Number: 6

Comment: How are PM CPMS certified? §63.7525(b)(1) requires the PM CPMS to be installed, certified, operated, and maintained in accordance with the site-specific monitoring plan, required per §63.7505(d), which in turn identifies §63.8(d). [And §63.8(e) for performance evaluations of CMS says the same, i.e., follow the plan.]

40 CFR 63.8(d) does not specify the individual Performance Specifications; but in §63.8(c)(6) it states that CPMS must be “calibrated prior to use” and “checked daily...”.

Do PM CPMS only need to be calibrated according to the manufacturer’s instructions, and if they are not technically certified, could “certified” be changed to “calibrated” in §63.7525(b)(1)?

Response: See the response to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 44.

Commenter Name: Lee Zeugin and Lauren Freeman
Commenter Affiliation: Utility Air Regulatory Group (UARG)
Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1
Comment Excerpt Number: 27

Comment: EPA has not addressed UARG’s concerns regarding the ability of PM CEMS to measure accurately at the level of the standard for new coal-fired boilers, even if PS 11 correlation is not required.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 85.

Commenter Name: Melvin E. Keener
Commenter Affiliation: Coalition for Responsible Waste Incineration (CRWI)
Document Control Number: EPA-HQ-OAR-2002-0058-3454-A1
Comment Excerpt Number: 15

Comment: The PM CPMS provisions should be modified.

EPA is proposing to remove the requirement to install PM CEMs on biomass boilers and to modify the particulate matter (PM) continuous monitoring requirements for coal-fired boilers so they can be used as parametric monitors rather than emissions compliance monitors (76 Fed. Reg. at 80,609). EPA’s logic for removing the PM CEMs requirement for biomass boilers is based on the inability to calibrate these instruments. EPA logic for changing the requirements for coal-fired boilers is based on commenter’s concerns over the readiness of current PM CEMs technology and the technical effort and cost for recertification. EPA’s proposal places coal-fired boilers in a difficult position. On the one hand, EPA states these monitors do not have to comply with Performance Specification (PS) 11, while on the other hand, EPA’s proposed rule language requires the same host of requirements in a site-specific monitoring plan as any other continuous monitoring system (see §63.7540(a)(9) and §63.7505(d)). Without an EPA-approved

performance specification, how can a source possible "certify" a monitoring system? EPA apparently recognizes that the burden of complying with PS-11 is unreasonable for industrial boilers. However, the proposed rule has created a second problem of how to certify an instrument without a performance specification.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 44.

Commenter Name: Steve Gossett

Commenter Affiliation: Eastman Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3669-A2

Comment Excerpt Number: 17

Comment: D.2. PM CEMS Comment Summary: PM CPMS should be removed from the rule. It is unworkable for EPA to require certification of these systems with no agreed performance specification. Despite these points, if EPA maintains this requirement, it must allow for an adjustment of the operating limit demonstrated during the performance test.

EPA's proposal places sources in an untenable position if they are required to install, certify, and operate these monitoring systems. While on the one hand, EPA states these monitors do not have to comply with Performance Specification 11, presumably to reduce compliance burden, on the other hand, EPA's proposed rule language requires the same host of requirements in a site-specific monitoring plan as any other continuous monitoring system (*see* §63.7540(a)(9) and §63.7505(d)). Without an EPA-approved performance specification, how can a source possible "certify" a monitoring system? EPA apparently recognizes that the burden of complying with PS-11 is unreasonable for coal-fired industrial and institutional boilers as it states in the preamble. Although EPA has required PM CEMS in the Utility MACT, those boilers are many times larger than ICI boilers with commensurately larger PM emissions and associated impact. They also operate at relatively steady loads compared to industrial and institutional boilers that have to respond to frequent load swings. We request EPA remove from the final rule the requirement to install PM CPMS monitoring for coal-fired boilers larger than 250 mmBtu/hr. We are aware of only one facility in the country other than an electric utility that operate PM CEMS on coal-fired boilers. This facility is more akin to an electric utility as the four boilers range in size from 165 MW to 320 MW, the facility sells electricity, and the boilers are base-loaded without load swings. Before requiring such substantial monitoring burden on industrial and institutional sources, EPA should further evaluate these systems via field studies to determine the real-world practicality.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 44.

11C02. PM CPMS: Applicability

Commenter Name: Ashok K. Jain

Commenter Affiliation: National Council for Air and Stream Improvement, Inc. (NCASI)

Document Control Number: EPA-HQ-OAR-2002-0058-3505-A1

Comment Excerpt Number: 3

Comment: Removing PM CPMS requirements for biomass and multi-fuel units are based on the findings of a recent study carried out by Georgia-Pacific and NCASI [See submittal for Attachment 1]. This study consisted of installing PM CEMS, operating on the light scattering principle, on multi-fuel boilers at two different facilities. During this study, calibration testing was performed for both PM CEMS, and a follow-up Relative Response Audit (RRA) was also carried out on both PM CEMS. Two different fuel mixtures were burned during the calibration testing for each PM CEMS, and fuel mixtures burned during the RRA were slightly different than those combusted during the calibration testing. Although the two monitoring systems worked reasonably well and required minimal routine maintenance, the study identified two major problems with the backscattering monitoring system:

1. The relationship between stack gas PM concentration as measured by the PM CEMS and the manual reference method varied when the fuel mixtures were changed. This resulted in several different calibration equations for different fuel combinations. 2. The PM monitoring system also failed to meet EPA's relative response audit criteria when the monitoring system was tested three months after the initial installation and calibration. In addition to the PM monitoring instrument calibration issue, the study also identified significant challenges associated with (a) calibrating stack PM monitors when a source is operating at very low stack gas PM concentrations, and (b) reporting stack PM emissions as lb/MMBtu heat input. These challenges include:

- High variability in EPA Method 5 measured values observed during tests when dual sampling trains are used simultaneously on a stack with low PM concentrations.
- Difficulty associated with determining instantaneous flow rates of individual fuels in multi-fuel boilers due to the time delay between monitoring fuel flow rate and its firing in the boiler.
- Integrating, maintaining, and calibrating ancillary monitoring equipment required for determination of PM emission rates.
- Complexity of converting stack gas PM concentration to the PM mass emission rate in lb/MMBtu when burning multiple fuels at varying rates.

The findings of this study support EPA's conclusion that the currently available stack gas PM monitors are not capable of being used as compliance monitors on biomass boilers. The study results also show that because the relationship between stack gas PM concentration and instrument response varies with fuel mix, in order to develop a parameter which would indicate that the source was in compliance with the PM standards, the facility would have to carry out PM CPMS calibration tests using every possible fuel combination and fuel ratio. This would require months of testing with varying fuel mixes and would be very expensive and disruptive to a facility's operation. Even after carrying out such a study, the facility would not be able to establish a parameter not to be exceeded during routine operations to ensure compliance with the PM emission standards, thus eliminating the feasibility of using such monitors as CPM devices.

The results of the G-P/NCASI study also raise significant doubts regarding the feasibility of installing and calibrating a PM CPMS on coal-fired boilers which burn other fuels such as petroleum coke, sludge, OCC rejects, TDF, and biomass.

We therefore recommend that EPA should modify the requirement to install PM CPMS and make it applicable only to fossil fuel boilers burning only one kind of fossil fuel. The

requirements should not apply to biomass boilers or multi-fuel fossil-fuel boilers due to the difficulty in developing a stack parameter which could be used as the threshold for maintaining compliance with the standard.

Response: The EPA acknowledges the potential limitations of the light backscatter technology with respect to multiple fuels. The EPA believes that no other technologies commercially available would have been better suited for the application of multiple fuel boilers. It should also be noted that when the low concentrations were measured co-located versus just time synced that the variability between paired trains was greatly reduced. The EPA disagrees that PM CPMS is not viable technology to use as a parametric monitor for sources burning multiple fossil fuels.

Commenter Name: Bruce W. Ramme

Commenter Affiliation: Wisconsin Electric Power Company (WE Energies)

Document Control Number: EPA-HQ-OAR-2002-0058-3452-A1

Comment Excerpt Number: 3

Comment: We Energies supports EPA's proposal to remove the PM CEMS requirement for biomass units for the reasons indicated by EPA in the proposed rule.

Response: The EPA thanks the commenter for their support.

Commenter Name: Lenny Dupuis

Commenter Affiliation: Dominion Resources Services, Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3486-A1

Comment Excerpt Number: 8

Comment: We support EPA's proposal to eliminate the requirement to install PM CEMS on biomass units that was established in the March 2011 final rule. We agree with EPA's assessment that PM CEMS are not demonstrated for biomass units and that significant technical concerns exist regarding the ability of CEMS to effectively monitor emissions from biomass units. PM CEMS are calibrated and certified to measure emissions from a single fuel type and reliance on a single calibration point in terms of compliance assessment would be problematic for biomass units due to the variability and moisture content of the fuel.

Response: The EPA thanks the commenter for their support.

Commenter Name: David A. Buff, Golder Associates Inc.

Commenter Affiliation: Florida Sugar Industry (FSI)

Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1

Comment Excerpt Number: 23

Comment: The FSI strongly agrees that it is not appropriate to require the use of PM CEMS for biomass-fired boilers. Requiring PM CEMS on the FSI's hybrid suspension grate boilers could be particularly problematic, as explained in the FSI's petition for reconsideration (dated May 12, 2011).

Response: The EPA thanks the commenter for their support.

Commenter Name: Ashok K. Jain
Commenter Affiliation: National Council for Air and Stream Improvement, Inc. (NCASI)
Document Control Number: EPA-HQ-OAR-2002-0058-3505-A1
Comment Excerpt Number: 1

Comment: In the proposed regulation, EPA has specified that PM CPMSs are not required on boilers smaller than 250 MMBtu per hour heat input rate and on boilers complying with the alternative total select metal limit. NCASI supports this decision.

Response: The EPA thanks the commenter for their support.

Commenter Name: Michael L. Krancer
Commenter Affiliation: Pennsylvania Department of Environmental Protection (DEP)
Document Control Number: EPA-HQ-OAR-2002-0058-3507-A1
Comment Excerpt Number: 8

Comment: The final rule required the use of PM CEMS as compliance monitors for coal, biomass and residual oil units with heat input capacity greater than 250 MMBtulhr. In response to petitioners, EPA's proposed rule removes the PM CEMS requirement for biomass units, and the other affected sources would be required to employ PM monitoring technology as parametric monitors used to determine compliance with operating limits rather than emission limits.

The DEP supports the use of PM monitoring technology as parametric monitors instead of requiring PM CEMS. DEP agrees that this approach will be less burdensome and will reduce compliance costs.

Response: The EPA thanks the commenter for their support.

Commenter Name: Annabeth Reitter
Commenter Affiliation: NewPage Corporation
Document Control Number: EPA-HQ-OAR-2002-0058-3662-A2
Comment Excerpt Number: 3

Comment: NewPage Corporation supports EPA's stated intent not to require PM CPMS for biomass units.

Response: The EPA thanks the commenter for their support.

Commenter Name: Christopher Coleman
Commenter Affiliation: HOVENSA LLC. , Hess Corporation
Document Control Number: EPA-HQ-OAR-2002-0058-3673-A2
Comment Excerpt Number: 6

Comment: For the reasons set forth in its petition, HOVENSA supports EPA's revision to §63.7510(d) and §63.7525(b) clarifying that a PM CPMS is not required unless a boiler or

process heater has an average annual heat input rate greater than 250 MMBtu per hour from solid fossil fuel and/or residual oil.

Response: The EPA thanks the commenter for their support.

Commenter Name: Douglas A. McWilliams

Commenter Affiliation: American Municipal Power

Document Control Number: EPA-HQ-OAR-2002-0058-3685-A2

Comment Excerpt Number: 41

Comment: AMP supports EPA's removal of the PM CEM requirement for units greater than 250 mmBtu/hr. As AMP noted in its 2010 Comments, PM CEMS are an unproven and unfamiliar technology, and their installation and certification would be unduly burdensome and redundant in light of the opacity monitors already installed on most boilers of this size.

Response: The EPA thanks the commenter for their support.

Commenter Name: Allison Watkins, Baker Botts

Commenter Affiliation: Class of '85 Regulatory Response Group

Document Control Number: EPA-HQ-OAR-2002-0058-3608-A1

Comment Excerpt Number: 10

Comment: The Class of '85 appreciates EPA's consideration of particulate matter Continuous Parametric Monitoring Systems ("PM CPMS") as an alternative to the PM continuous emission monitoring system ("CEMS") requirement. However, PM CPMS are not a viable alternative for many units.

Response: The EPA thanks the commenter for their support of PM CPMS as an alternative for PM CEMS. The EPA acknowledges the concern over viability of PM CPMS.

Commenter Name: M.L. Steele

Commenter Affiliation: CraftMaster Manufacturing, Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3814-A1

Comment Excerpt Number: 13

Comment: PM GEM's, §63.7525(b) We support EPA's decision to not require PM GEM's on biomass-fired units.

Response: The EPA thanks the commenter for their support.

Commenter Name: Philip Lewis

Commenter Affiliation: Michigan Biomass - Grayling Generating Station

Document Control Number: EPA-HQ-OAR-2002-0058-3815-A1

Comment Excerpt Number: 3

Comment: Removal of continuous emission monitors (CEMs) for particulate matter for biomass. Our continuous opacity monitors and proper operation of our control equipment assures very low particulate emissions.

Response: The EPA thanks the commenter for their support.

Commenter Name: Randall D. Quintrell

Commenter Affiliation: Georgia Paper & Forest Products Association

Document Control Number: EPA-HQ-OAR-2002-0058-3451-A1

Comment Excerpt Number: 5

Comment: The proposed requirement to use PM CEMS as parametric monitoring for larger units burning fossil fuel also is unwarranted. The use of total power for electrostatic precipitators, scrubber operating parameters, and/or opacity as a means of demonstrating good operation of control devices is sufficient and proven for parametric monitoring, and these provide the compliance assurance required. The installation, operation and maintenance of PM CEMS, even without certification, is extremely burdensome, expensive and unnecessary. The reasons such data are unreliable and inappropriate for use as a direct measure are the same reasons it is unreliable and inappropriate for parametric monitoring. Bad data is bad data, no matter what the end use.

Response: The EPA disagrees with the commenter that PM CEMS as parametric monitors would not be indicative of trends and changes in emissions in addition to being effective as a control monitoring device.

Commenter Name: Melvin E. Keener

Commenter Affiliation: Coalition for Responsible Waste Incineration (CRWI)

Document Control Number: EPA-HQ-OAR-2002-0058-3454-A1

Comment Excerpt Number: 17

Comment: All of this seems to point out the uncertainty over the use of PM CEMS for this source category. CRWI suggests that until all this uncertainty can be worked out, EPA should remove the PM CEMS requirement for both biomass boilers and coal-fired boilers. The Agency should conduct field studies on these instruments to determine their real-world practicability. After further evaluation of these systems, the Agency may be able to clear up these uncertainties associated with these instruments on these sources and create clear methods for certifying and operating these types of instruments.

Response: For a response to general opposition to PM CEMS requirements, please see comment EPA-HQ-OAR-2002-0058-3451-A1, excerpt 5.

Commenter Name: Douglas A. McWilliams

Commenter Affiliation: American Municipal Power

Document Control Number: EPA-HQ-OAR-2002-0058-3685-A2

Comment Excerpt Number: 45

Comment: Units Employing CEMS or PM CPMS Should Not Be Excluded From Emissions Averaging

In the Proposed Rule, EPA established a new provision excluding units employing a CEMS or PM CPMS from participating in emissions averaging. EPA offered no explanation for this exclusion. Sources using the stack testing option have the ability to extrapolate their test results over a 30-day period using operating data, and establish 30-day averages that can be compared to the data for units operating continuous monitoring systems. Furthermore, EPA allowed units with CEMS to participate in emissions averaging in the recently finalized Utility MACT rule .48 EPA should provide the smaller municipal utilities operated by AMP members subject to Boiler MACT with at least the same flexibility it provides the much larger electric generating units subject to the Utility MACT rule. EPA should not discourage the use of CEMS (where they are optional) in cases where a source elects to utilize emissions averaging. It also unnecessarily restricts emissions averaging among fossil fuel fired units to those of 250 MMBtu/hr or less, due to the PM CPMS restriction. EPA should not discourage use of CEMS as a compliance option or limit emissions averaging to smaller sources. On the contrary, EPA should provide sources that use a continuous direct measure of emissions with more flexibility, not less, than sources using periodic stack testing and parameter monitoring.

[Footnote 48: *See* 40 C.F.R. §63. 10009 (not yet published).]

Response: The EPA agrees with the commenter and has revised the rule to allow emissions averaging for facilities using CEMs to demonstrate compliance.

Commenter Name: Eric Guelker, Alliant Energy Corporate Services, Inc.

Commenter Affiliation: Interstate Power and Light Company (IPL) and Wisconsin Power and Light Company (WPL), Alliant Energy Corp.

Document Control Number: EPA-HQ-OAR-2002-0058-3492-A1

Comment Excerpt Number: 6

Comment: Alliant Energy appreciates that the EPA has considered the PM CPMS as an alternative to the PM CEM requirement. However, we still believe that this requirement is too restrictive and that EPA should provide sources the flexibility to determine the most appropriate continuous compliance method (CEM, CPMS fuel analysis or stack testing). Therefore, we request that the EPA should allow performance stack testing as another additional compliance option in this rule, similar to what is in the final MATS.

Response: The EPA thanks the commenter for their support of PM CPMS as an alternative to PM CEMS. For a response to the request that the EPA should allow sources more flexibility in determining the most appropriate compliance method, please see comment EPA-HQ-OAR-2002-0058-3685-A2, excerpt 45.

Commenter Name: Dirk J. Krouskop

Commenter Affiliation: MeadWestvaco Corporation (MWV)

Document Control Number: EPA-HQ-OAR-2002-0058-3493-A1

Comment Excerpt Number: 15

Comment: MWV supports EPA's decision to not require PM CEMs monitoring for biomass units. MWV does not believe there is enough proven application of these systems on biomass units and that they are unnecessary with the other continuous parametric monitoring systems that EPA has discretion to require. In fact, MWV believes that EPA has the discretion to remove this requirement for coal fired boilers as well for the same reasons and should do so.

Response: The EPA thanks the commenter for their support of the removal of PM CEMS requirements for biomass-fired boilers. The requirement for coal-fired boilers to install a PM CEMS was replaced in the proposal with the requirement to install a PM CPMS.

Commenter Name: David A. Buff, Golder Associates Inc.

Commenter Affiliation: Florida Sugar Industry (FSI)

Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1

Comment Excerpt Number: 25

Comment: It should be clarified in the final Boiler MACT Rule that a PM CPMS is never required for a biomass-fired unit, even when that unit also burns fossil fuels. The rule currently requires a PM CPMS if a unit (including a unit designed to burn biomass) has an average annual heat input rate of 250 MMBTU/hr for fossil fuel. See 63.7525(b).

Response: We agree with the commenter that PM CPMS was not intended to be required for units that are in any of the biomass subcategories. 63.7525(b) has been revised to clarify that the requirement only applies to units in the coal or heavy liquid subcategories.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 45

Comment: At a minimum, EPA should provide clarification that units in the biomass subcategories do not have to install PM CPMS, even if they fire more than 250 MMBtu/hr of fossil fuel. EPA notes in the preamble that these types of monitors cannot be feasibly applied to biomass units, due to significant technical concerns and the unpredictable variety of biomass fuel constituents and fuel moisture content. *Id.* at. 80609.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3504-A1, excerpt 25.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 97

Comment: If the PM CPMS requirements aren't removed, EPA should provide clarification that multi-fuel units and units in the biomass subcategories do not have to install PM CPMS, even if they fire more than 250 MMBtu/hr of fossil fuel.⁴⁵ EPA discusses at 76 Fed. Reg. 80609 the reasons why these monitors cannot be feasibly applied to biomass units:

[Footnote 45: Despite EPA pronouncements suggesting biomass units would not be subject to the PM CPMS provisions, rule language at 63.7525(b) fails to exclude biomass units that also fire fossil fuels at more than 250 MMBtu/hr on an average annual basis.]

Response: For a response to the request that biomass units should not be required to install PM CPMS even if co-fired with more than 250 MMBtu/hr of fossil fuel, please see comment EPA-HQ-OAR-2002-0058-3504-A1, excerpt 25. For a response to the request that multi-fuel units should be exempt from PM CPMS requirements, please see comment EPA-HQ-OAR-2002-0058-3505-A1, excerpt 3.

Commenter Name: Ashok K. Jain

Commenter Affiliation: National Council for Air and Stream Improvement, Inc. (NCASI)

Document Control Number: EPA-HQ-OAR-2002-0058-3505-A1

Comment Excerpt Number: 2

Comment: We are concerned about the requirements in section 63.7525 (b) where EPA has proposed that all boilers with an average annual heat input rate greater than 250 MMBtu per hour from solid fossil fuel and/or residual oil and demonstrating compliance with the PM limit, must install, certify, maintain, and operate a PM CPMS. This requirement inadvertently includes biomass units that burn at least 10 percent biomass or bio-based solids on an annual heat input basis, in combination with solid fossil fuels, liquid fuels, or gaseous fuels. Based on rationale and language presented in section D (2) of the preamble, it is our understanding that EPA intended to not require PM continuous emission monitors on biomass units.

1. EPA should clarify the rule by stating that the requirement to install and use PM CPMS does not apply to boilers in the biomass category.
2. EPA should not require the use of a PM CPMS on any multi-fuel boiler.

Response: For a response to the request for clarification that all biomass-fired boilers are exempt from PM CPMS requirements, please see comment EPA-HQ-OAR-2002-0058-3504-A1, excerpt 25. For a response to concern over the viability of PM CPMS for multi-fuel boilers, please see comment EPA-HQ-OAR-2002-0058-3505-A1, excerpt 3.

Commenter Name: Stephen E. Woock

Commenter Affiliation: Weyerhaeuser Company

Document Control Number: EPA-HQ-OAR-2002-0058-3523-A1

Comment Excerpt Number: 18

Comment: In the re-proposed rule EPA substituted a provision to require any unit burning more than 250 mmBtu per hour annual average of solid fossil fuels or residual oil to establish a PM continuous parameter monitoring system (CPMS) operating parameter. This proposed substitute requirement suffers from much the same problems as already discussed, and we refer EPA to the extensive comments on this by our trade groups. In addition, despite public comments from EPA officials that they were removing the PM CEMS requirement for biomass units, the rule language fails to exclude all biomass units from the PM CPMS requirement. The rule language at §63.7525(b) requiring the PM CPMS as an operating parameter for PM would include multi-fuel

units that qualify under the definitions as a unit designed to burn biomass/bio-based solid (>10% biomass by rule definition) –in this case biomass units that also happen to combust on annual average more than 250 mmBtu/hour of solid fossil fuel and/or residual oil. If EPA decides to retain the PM CPMS for fossil fuel units, we request EPA remove this requirement for units qualifying as biomass units by rule definition since the operating parameter would not provide information relevant to compliance with the emission limit.

Response: The EPA acknowledges the commenter's concern of PM CPMS requirements for units larger than 250 MMBtu/hr. For a response to the request for clarification that all biomass units should be exempt from the PM CPMS requirements even if co-fired with greater than 250 MMBtu/hr of fossil fuel, please see comment EPA-HQ-OAR-2002-0058-3504-A1, excerpt 25.

Commenter Name: Annabeth Reitter

Commenter Affiliation: NewPage Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3662-A2

Comment Excerpt Number: 13

Comment: Based upon the language in the preamble, it is our understanding that it is EPA's intent not to require PM continuous emission monitors on biomass boilers due to a number of technical issues discussed in the preamble (see pages 80609-80610). EPA has also decided not require the installation of PM CPMSs on boilers smaller than 250 MMBtu per hour heat input rate and on boilers complying with the alternative total select metal limit.

In section §63.7525 (b) EPA has proposed that all boilers with an annual heat input rate greater than 250 MMBtu per hour from solid fossil fuel and/or residual oil and demonstrate compliance with the PM limit must install, certify, maintain, and operate a PM CPMS. NewPage is concerned this requirement also includes boilers greater than 250 MMBtu per hour that burn more than 10% biomass or bio-based solids on an annual heat input basis, in combination with solid fossil fuels, liquid fuels, or gaseous fuels (e.g. units in a biomass subcategory). We, therefore, recommend that:

1. EPA clarifies the rule by stating that the requirement to install and use PM CPMSs does not apply to any boilers in a biomass subcategory; and
2. EPA also not require the use of a PM CPMS on any boiler that burns more than one fuel.

The above recommendations are based on the finding of a recent study carried out by Georgia-Pacific (GP) and NCASI. The results of these studies are being submitted to EPA directly by NCASI.

Response: For a response to the request for clarification that all biomass-fired boilers are exempt from PM CPMS requirements, please see comment EPA-HQ-OAR-2002-0058-3504-A1, excerpt 25. For a response to concern over the viability of PM CPMS for multi-fuel boilers, please see comment EPA-HQ-OAR-2002-0058-3505-A1, excerpt 3.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 88

Comment: PM CEMS have been demonstrated in practice on coal-fired utility boilers and at least one coal-fired industrial boiler. They have not been demonstrated on biomass-burning boilers. A review of all the types of PM CEMS and potential suitability for use on biomass-fired boilers is problematic for a number of reasons.

PM CEMS do not measure mass. Because PM monitors do not measure mass directly, they must be calibrated against some manual, PM reference method measurement procedure like EPA Methods 5, 5i or 17. The fundamental problem arises when the characteristics of the emitted PM exhibit significant variability and this variability in the particulate properties translates into a shift or alteration in the instrument's calibration curve.

Biomass, as well as CISWI units, which combust a mixture of fuels and which operate at variable loadings pose significant challenges in establishing meaningful correlations. In order to establish a calibration curve, one needs to source test the emissions from the stack and correlatethose to specific instrument readings.

Response: For a response to claims that biomass and multi-fuel units will experience significant calibration issues with PM CEMS, please see comment EPA-HQ-OAR-2002-0058-3505-A1, excerpt 3.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 89

Comment: As fuel and fuel mixes vary, particle size distributions generated vary significantly. Biomass combustion emission distributions are characterized by a bimodal particulate distribution.¹⁶ [See submittal for Figure 1.]

This is due to the vaporization of volatile ash species in the wood-like potassium and sodium biomass ash that yields a bimodal characteristic with peaks of nominally 0.5 and 20 to 40 microns. Coal ash, on the other hand, tends to exhibit a more mono modal distribution without the submicron peak. Data available for PM CEMS effective is primarily limited to coal, and data on how PM CEMS will respond to monitoring biomass emissions is expected to be problematic.

[Footnote 16: "BIO-AEROSOLS – Aerosols in Fixed Bed Biomass Combustion," Presented by Professor Ingewald Oberberger, Ph.D., Graz University of Technology, Budapest, October 2003.]

Response: For discussion on the viability of PM CEMS for multi-fuel units, please see comment EPA-HQ-OAR-2002-0058-3505-A1, excerpt 3. The EPA acknowledges the potential for particle size distribution to vary and has allowed for technologies that use other particulate matter characteristics for measurement.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 90

Comment: In addition to the variability of the fuels and fuel mixtures the operating load (firing rate) of the boiler will produce varying particulate loading which will challenge the robustness of any PM CEM correlation and calibration. This has been demonstrated during a study conducted by the Electric Power Research Institute (EPRI) of PM CEMS. The results of the study indicate that when inlet loading to ESP's are changed due to different fuel mixtures, the exhaust emissions have a different particle size and distributions. Therefore, a single or even a few correlation curves cannot be used to provide representative compliance correlations over an extensive range of fuels, fuel mixtures and loads. The results of the EPRI Study indicate that when a protocol is developed to simulate varying particle sizes and loads it results in inaccurate mass emissions estimates.¹⁷

For units such as biomass units, which may use a variety of biomass materials and vary production, or for CISWI units, which combust a varying mixture of materials, testing every possible fuel mixture to develop calibration curves for each is infeasible, given the extensive range of possible fuel mixtures.

In practice, changing the fuel mix for the purpose of correlation testing may alter the loadings; however, it would be difficult to do in a systematic way, and in order to gather the reference data needed to develop an acceptable correlation. Thus, for variable fuel and production rate units with variable emission characteristics in the stack where the PM CEMs is being used as a monitor, we conclude that establishing meaningful curves, figuring out how to match those to the fuel and production mixes and finally correlating these with emissions in any meaningful way is impractical. Basically, for each fuel mix that may be used, one would need to be able to establish a correlation curve. Then, the instrument would need to use the right calibration curve for the proper fuel mixture in order for any meaningful correlation with particulate to be established. This solution is not technically feasible.

Beyond this, there are a number of correlation issues. For instance, the PM response to the light scattering instruments are very dependent on particle size, shape and even color. Other technologies have other limitations.

Response: For a response to the claim that biomass and multi-fuel units will experience significant calibration issues with PM CEMS, as well as discussion on the viability of PM CEMS for multi-fuel units, please see comment EPA-HQ-OAR-2002-0058-3505-A1, excerpt 3.

Commenter Name: Annabeth Reitter

Commenter Affiliation: NewPage Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3662-A2

Comment Excerpt Number: 14

Comment: The results of the GPINCASI study raise significant doubts regarding the feasibility of installing and calibrating PM CPMSs on coal-fired boilers which also burn other fuels including petroleum coke, sludge, OCC rejects, TDF, biomass, etc. We therefore recommend that EPA modify the requirement to install PM CPMSs and not make it applicable to any unit that burns more than one kind of fuel.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3505-A1, excerpt 3.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 86

Comment: CIBO asks EPA to confirm that the boiler size threshold for determination of whether or not a PM CPMS must be installed is the average annual heat input, i.e., annual heat input divided by the number of actual operating hours in the year. Similar to the Utility MACT, CIBO suggests that this value be determined using three consecutive years beginning after the compliance date to determine average annual heat input.

Response: We disagree with the suggestion for the determination to be based on the annual heat input after the compliance date. The required monitoring are to be installed and in operation on the compliance date for demonstrating continuous compliance. 63.7525(b) clearly states that the requirement is based on the "annual heat input" which is defined in the rule as:

Annual heat input means the heat input for the 12 months preceding the compliance demonstration.

Commenter Name: Richard D. Garber

Commenter Affiliation: Boise Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3686-A2

Comment Excerpt Number: 20

Comment: EPA needs to respond to technical concerns raised by numerous commenters and clarify that PM CEMS are not required for biomass units, including those with a heat input greater than 250 mmBTU/hr.

The technology for continuous particulate monitoring has not been sufficiently demonstrated that it can be installed on boilers in the pulp and paper industry to meet the required calibration and correlation requirements outlined in EPA Performance Specifications (PS-11), especially at the extremely low particulate levels necessary to demonstrate compliance with the standard. For mills that utilize wet electrostatic precipitators as stand-alone control devices or in conjunction with wet scrubbers for particulate and acid gas removal, it will be technically infeasible to use PM CEMS for either direct compliance measurement or as parametric monitoring systems as suggested by EPA in the December 23, 2001 rules. These technical feasibility issues are problematic regardless of the size of the boiler, and the requirements for biomass boilers with a heat input greater than 250 mmBTU/hr should be removed from rule language. Boise references the detailed AF&PA and NCASI technical comments on this issue and requests that EPA make clear in the rule that the PM CEM requirement is removed.

Response: The EPA has removed the requirement for biomass boilers to show compliance with PM CEMs.

11D. CO CEMS: Specifications/Operations

Commenter Name: Gary Melow, Director

Commenter Affiliation: Michigan Biomass (MB)

Document Control Number: EPA-HQ-OAR-2002-0058-3478-A1

Comment Excerpt Number: 4

Comment: We strongly support a longer averaging time for CO for boilers already equipped and required to operate CEMs, with adjusted emission levels to reflect the variability we see when operating CEMs compared to short term stack tests.

Response: The EPA thanks the commenter for their support.

Commenter Name: Ashok K. Jain

Commenter Affiliation: National Council for Air and Stream Improvement, Inc. (NCASI)

Document Control Number: EPA-HQ-OAR-2002-0058-3505-A1

Comment Excerpt Number: 5

Comment: In Section 63.7525 (a) of the proposed rule EPA has specified that if a facility is subject to CO emission limits in Tables 1 or 2, to monitor the CO levels it must install, operate and maintain a CO monitor at the outlet of the boiler or process heater. Such CO monitors are also required to satisfy the requirements of PS 4, 4A or 4B.

EPA is, however, aware that it is not possible to certify any gas monitor according to applicable Performance Specifications if the monitor is located at the outlet to the boiler. This inability to certify is caused by stratification of gases at the boiler/process heater outlet.

We recommend the EPA should change this requirement and permit installation of CO CEMSs in the stack where such monitors can be certified according to PS 4, 4A or 4B. The installation of the monitor in the stack would not have any impact on determining the compliance status of the source since the CO data will have to be corrected to 3% O₂, thus negating the impact of any dilution of the stack gas due to leaks in the system.

Response: The EPA agrees with the commenter and has changed the rule to indicate that a source complying with the rule by using CO CEMS must satisfy the requirements of the appropriate Performance Specification for such monitoring and must sample flue gas following any installed emission control devices or flue gas recirculation ductwork and prior to the stack exit to the atmosphere.

Commenter Name: David A. Buff, Golder Associates Inc.

Commenter Affiliation: Florida Sugar Industry (FSI)

Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1

Comment Excerpt Number: 40

Comment: Section 63.7525(a)(1) of the Proposed Boiler MACT Rule states "If a CO CEMS is used, the carbon monoxide level shall be monitored at the outlet of the boiler or process heater." Such CO monitors are also required to satisfy the requirements of PS 4, 4A or 4B. It is not

possible to certify any gas monitor according to applicable Performance Specifications if the monitor is located at the outlet to the boiler. This inability to certify is caused by stratification of gases at the boiler/process heater outlet.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3505-A1, excerpt 5.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 85

Comment: Proposed §63.7525(a)(1) requires that a CO CEMS monitor the CO level at the "outlet" of the boiler or process heater. Such CO monitors are also required to satisfy the requirements of PS 4, 4A or 4B. It is not possible to certify any gas monitor according to applicable Performance Specifications if the monitor is located at the outlet to the boiler. This inability to certify is caused by stratification of gases at the boiler/process heater outlet. In addition, for units equipped with add-on controls or flue gas recirculation systems the "outlet" could be construed to be either before or after these controls. Since these systems may impact the CO level, the measurement must be after any controls or recirculation (i.e., just before the gas is released to the atmosphere. EPA should revise the last sentence of §63.7525(a)(1) by adding the underlined language, to read as follows: If a CO CEMS is used, the carbon monoxide level shall be monitored at the outlet of the boiler or process heater, after any add-on controls or flue gas recirculation system and just before release to the atmosphere.

The installation of the monitor in the stack would not have any impact on determining the compliance status of the source since the CO data will have to be corrected to 3% O₂, thus negating the impact of any dilution of the stack gas due to leaks in the system.

Response: For a response to the siting of the CO CEMS, see comment EPA-HQ-OAR-2002-0058-3505-A1, excerpt 5.

Commenter Name: Richard D. Garber

Commenter Affiliation: Boise Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3686-A2

Comment Excerpt Number: 19

Comment: EPA should correct and clarify the location required for placement of CO CEMS monitoring devices

Boise believes that EPA may have unintentionally specified that CO CEMS monitor the CO level at the "outlet" of the boiler or process heater, as specified in 40 CFR 63.7525(a)(1), rather than downstream of the control device in the stack. As has been stated previously in our comment letter, Boise has two boilers at its facilities that already have CO CEMS installed for reasons other than compliance with the Boiler MACT rules.

In order to achieve quality assurance requirements, these units have been installed not at the boiler outlet, but in the boiler stack following the emissions control device. Boise believes that

EPA does not intend for sources that have CO CEMS already installed to be required to move their existing systems as this would unnecessarily cause the facilities to incur significant relocation costs. Furthermore, because of stratification of gases, it would be difficult if not impossible for CO CEMS to meet required Performance

Specifications if they were installed at the boiler outlet rather than in the stack. For these reasons, we request that the stack location be corrected to indicate CO CEMS, if existing or already installed, shall be downstream of all pollution control device. Minor pollutant concerns due to tramp air or leakage can be addressed by the correction to 3% oxygen.

Response: For a response to the siting of the CO CEMS, see comment EPA-HQ-OAR-2002-0058-3505-A1, excerpt 5.

Commenter Name: David A. Buff, Golder Associates Inc.

Commenter Affiliation: Florida Sugar Industry (FSI)

Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1

Comment Excerpt Number: 41

Comment: The proposed rule requirement may also present conflicts with existing CO CEMS installed as a requirement of their PSD permit. Such systems normally measure CO at the boiler stack, where other parameters (NO_x, O₂, etc.) are also measured. Such systems would have to be relocated to the boiler outlet, where CO levels may be different than at the stack due to leaks in ductwork, air pollution control devices, etc. Boilers which are operated to meet a certain CO level at the stack may have to modify their operations if the CO measurement point is changed. It should be noted that all of the CO data submitted by the FSI, including the stack test data and CEMS data, were obtained at the boiler stack.

Response: For a response to the siting of the CO CEMS, see comment EPA-HQ-OAR-2002-0058-3505-A1, excerpt 5.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 95

Comment: Requirements associated with the optional CO CEMS need to be clarified.

Proposed §63.7525(a)(1) requires that a CO CEMS must monitor the CO level at the outlet of the boiler or process heater. It is unclear where the “outlet” is and this needs to be clarified. For BPH equipped with add-on controls, such as NO_x catalyst systems, and BPH equipped with flue gas recirculation energy efficiency systems the “outlet” could be construed to be either before or after these controls. Since these systems can impact the CO level, we believe the measurement must be after any controls or recirculation (i.e., just before the gas is released to the atmosphere. We request EPA make this clear in the final rule by revising the last sentence of §63.7525(a)(1) as follows.

If a CO CEMS is used, the carbon monoxide level shall be monitored at the outlet of the boiler or process heater after any add-on controls or flue gas recirculation and just before release to the atmosphere.

Response: For a response to the siting of the CO CEMS, see comment EPA-HQ-OAR-2002-0058-3505-A1, excerpt 5.

Commenter Name: Bart Sponsellar

Commenter Affiliation: Wisconsin Department of Natural Resources

Document Control Number: EPA-HQ-OAR-2002-0058-3527-A2

Comment Excerpt Number: 24

Comment: Many of the Department's comments are formulated from a common basis. The Department believes that there is significant opportunity, in context of the issues open for comment, to achieve the same or better environmental results and reduce compliance cost by allowing CMS parametric monitoring for PM, Hg and CO and O₂ monitoring for good combustion. One basic benefit in pursuing an alternative compliance demonstration is better parametric monitoring and stable combustion conditions which will allow for stack testing on a biennial schedule. This is very important for sources in reducing compliance cost and aligning stack testing with current Wisconsin stack testing requirements.

Although not providing absolute certified values, a CMS system which directly monitors the regulated pollutant ensures better overall environmental results as compared to an annual stack test. EPA has basically followed this premise in proposing the use PM CEMs, CO CEMs and Hg CEMs as an alternative in demonstrating compliance. EPA has also shown with the proposal of a PM CMS and oxygen trim systems for parametric monitoring that they believe quality monitoring can be standardized without requiring full CEMs certification. In this approach CMS data is correlated to the periodic stack test for each source and ensures ongoing compliance. The CO CMS is also correlated to good combustion over different loads with the source required to continuously trim the system to good combustion when operating.

Response: The EPA disagrees with the commenter that a CO CMS system is an applicable compliance alternative for this rule. Compliance with a CO CEMS will provide the necessary data QA/QC to meet a ten day rolling average limit, and compliance with a single stack test measurement per year is much better achieved through an O₂ monitoring system and not a CO CMS trying to comply with the three hour stack test data, as such a monitor is not likely to meet compliance assurance when loads swing or fuel moisture varies greatly.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 96

Comment: Proposed §63.7525(a)(7) requires that a CO CEMS must collect "at least two 15-minute data values during an hour when CEMS calibration, quality assurance, or maintenance activities are being performed." Such a requirement is impossible if the needed quality assurance

or maintenance activity takes more than 30 minutes, which can occur. Doing required maintenance and quality control is required by this rule and complying with that mandate should not put operators in violation. Rather, time periods with inadequate data should not be included in compliance averages, as provided in the part 63 General Provisions, and all such periods should be recorded and reported, also as specified in the part 63 General Provisions that are applicable to this regulation. Thus we recommend §63.7525(a)(7) be revised to specify that hours where data is unavailable for at least two fifteen minute periods due to CEMS calibration, quality assurance, or maintenance activities are not to be included in daily compliance averages and shall be treated as specified in §63.7535(d) and §§63.8 and 63.10 of the part 63 General Provisions.

Response: The EPA points out to the commenter that a minimum of one cycle of sampling, analyzing, and data recording per fifteen minute period is the requirement of §63.7525(a)(7). Where a CO CEMS is capable of conducting such a cycle in one minute, the first minute and final minute of any hour would meet the requirement of the rule. This would allow up to 58 minutes for the source operator to conduct CEMS calibration, quality assurance, or maintenance activities in any given hour.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 97

Comment: Proposed §63.7540(a)(8)(ii) specifies that if you are using a CO CEMS you must maintain a CO emissions level below or at your Table 1 or 2 limit at all times [emphasis added]. However, that limit does not apply during startup and shutdown. §63.7540(a)(8)(ii) should be revised to exclude startup and shutdown periods from the requirement to comply with the Table 1 or 2 CEMS CO limit.

Response: The EPA points out to the commenter that startup and shutdown data is exempted by the heading of Table 2.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 112

Comment: Achievable span values should be specified for CO CEMS.

Proposed §63.7525(a)(6) requires that the span value of a CO CEMS must be two times the applicable emission limit. The availability of CO CEMS for the lower CO standards is unclear. For instance, a quick review indicates 100 ppm is the lowest span advertised by one major manufacturer. Additionally, it is impossible to be this precise. For instance, the proposed CO limit for units designed to burn heavy liquids is 18 ppm. Twice that is 36 ppm. Thus, a CO CEMS that has a span of 35 ppm or 37 ppm is a deviation, even though that difference makes no

difference in the quality of the measurement. Span requirements should be established as a range and be consistent with manufactured units (e.g., include 100 ppm in this case). Thus, we recommend the span requirement be 2-6 times the CO limit, which will include 100 ppm for the lowest CO CEMS limit in the proposal.)

Response: EPA Method 10 for measurement of CO references EPA Method 7E which defines the measurement span as the high level gas value, not the instrument scale/ range. Therefore, where §63.7525(a)(6) requires that the span value of a CO CEMS must be two times the applicable emission limit, this means that the measurement span value must be two times the applicable emission limit, not the particular instrument measurement range.

Commenter Name: Mark Anthony

Commenter Affiliation: Alyeska Pipeline Service Company

Document Control Number: EPA-HQ-OAR-2002-0058-3684-A2

Comment Excerpt Number: 8

Comment: A clarification which would be beneficial in the rule is to acknowledge the acceptability of using a single CO CEMS system to monitor multiple affected boilers simultaneously as long as the measurement criteria of at least one reading every 15 minutes per affected unit is met. At the VMT, the three power boilers route to a common stack and since the rule does not provide a single CO limit for combined stack configurations, like it does for PM/HCI and Mg, it is implied that individual boiler CO exhaust measurements are required. In order to simplify the monitoring, reduce redundancy, and optimize limited space, Alyeska believes there would be benefit in this rule if EPA acknowledged this option.

Response: The EPA allows monitoring of combined stacks to be accomplished through sample system switching, provided that the sampling system provides for a unique and representative emissions measurement from each of the individual sources as required by §63.7525.

Commenter Name: Heather Parent

Commenter Affiliation: Maine Department of Environmental Protection

Document Control Number: EPA-HQ-OAR-2002-0058-3691-A2

Comment Excerpt Number: 17

Comment: The proposed rule specifies in 40 CFR 63.7525(a)(1) that if a CO CEMS is used, the carbon monoxide level shall be monitored at the outlet of the boiler or process heater. CO CEMS operating in Maine do not collect flue gas samples at the outlet of a boiler, but either in the ductwork connecting the last piece of control equipment to the exhaust stack or in the exhaust stack, itself. The location where the flue gas sample is taken should not matter so long as the flue gas sample monitored by the diluent monitoring system (oxygen or carbon monoxide) is taken from the same place. Maine DEP recommends that EPA revise any language in the proposed rule regarding the location where the monitoring takes place to allow for any location that meets the performance specification for the particular monitoring system.

Response: For a response to the siting of the CO CEMS, see comment EPA-HQ-OAR-2002-0058-3505-A1, excerpt 5.

Commenter Name: Samuel H. Bruntz
Commenter Affiliation: Alcoa Power Generating, Inc.
Document Control Number: EPA-HQ-OAR-2002-0058-3755-A1
Comment Excerpt Number: 12

Comment: With respect to CO, the proposed limit is expressed as ppm, dry basis, corrected to 3% O₂. For a wet scrubber controlled boiler, it would be necessary to operate an oxygen CEMS and a continuous moisture measurement system or computer system that calculates moisture content with a psychrometric chart assuming 100% saturation. Alcoa-Warrick has a flow monitor that measures airflow on a wet basis. In order to avoid the additional costs associated with installation of an O₂ CEMS, and some type of moisture monitoring system, Alcoa-Warrick suggests that an item 10 be added to Table 4, as follows:

10. CO CEMS: For boilers and process heaters subject to a carbon monoxide emission limit that demonstrate compliance with a CO CEMS as specified in § 63.7525(a), maintain the carbon monoxide level such that It does not exceed below the concentration recorded during the applicable 40 CFR 60, Appendix B performance specification tests that corresponds to the CO emission limit expressed as corrected to 3% oxygen, dry basis.

Response: The EPA disagrees with the commenter that a moisture correlation determined during annual performance specification test is robust enough to prove compliance with a ten day rolling average limit.

11E. Hg CEMS

Commenter Name: Ashok K. Jain
Commenter Affiliation: National Council for Air and Stream Improvement, Inc. (NCASI)
Document Control Number: EPA-HQ-OAR-2002-0058-3505-A1
Comment Excerpt Number: 4

Comment: In Section 63.7525 (l) of the proposal, EPA has specified that “For each unit for which you decide to demonstrate compliance with the mercury or hydrogen chloride emissions limits in Tables 1 or 2 of this subpart by use of a CEMS for mercury or hydrogen chloride, you must install, certify, maintain, and operate a CEMS measuring emissions discharged to the atmosphere.” EPA has asked for comments on this proposal on the use of mercury CEMSs. NCASI supports EPA’s decision to only require mercury CEMSs on those boilers which demonstrate compliance with the emission standard by using mercury CEMSs. All other boilers are exempt from the requirement to install mercury CEMSs. Our support for not requiring the installation of mercury CEMSs on the excluded category of boilers is based on the findings of a study carried out by NCASI on a biomass boiler which was co-firing coal at the time of the study and was equipped with a wet scrubber for PM control [See submittal for Attachment 2].

A Thermo-Fisher mercury CEM was installed on the boiler and tests were conducted to evaluate the performance of the CEM. During the study, stack gas mercury content was measured using EPA Method 29 to allow a comparison between Method 29 and CEM measured mercury emission rates and to determine whether an acceptable correlation could be developed between

the two measurements. The emission data are plotted in Figure 1. [See submittal for Figure 1]
The results of the regression analysis are summarized in Table 1. [See submittal for Table 1]

The results in Table 1 show that the instrument response of the mercury CEM could not be correlated with the emissions from the boiler when measured with Method 29, and the instrument failed the EPA criteria for CEMSs. Based on these findings, it would not be appropriate to require mercury CEMSs on biomass boilers except for those facilities that demonstrate compliance through a CEMS.

The details of the study are included as Attachment 2 with these comments.

Response: The EPA thanks the commenting organization for their support. We have reviewed the study submitted by the commenting organization in Attachment 2 to their letter and agree that the data presented does not show good correlation between Method 29 and the Hg CEMS; however, we would not immediately conclude that the Hg CEMS cannot perform properly on this source and pose the following potential reasons for the poor correlation documented.

First, the Hg CEMS was not installed at a representative sampling point location. Are there any other data to support the location chosen?

Second, it appears that Method 29 as performed for these tests was not sensitive enough to develop a reasonable correlation with the Hg CEMS. The nine Method 29 emissions values used in the attempted correlation included 18 to 22 percent contribution from non-detect analytical results from some fractions of the sampling trains. Use of a more sensitive method such as Method 30B or ASTM D6784-02 should yield more definitive results.

Finally, we were unclear as to why the commenting organization chose to analyze the data using the correlation approach in Performance Specification 11 for PM CEMS as opposed to the relative accuracy approach of Performance Specification 12A (PS 12A) for Hg CEMS.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 50

Comment: ACC supports EPA's decision not to require Hg CEMS on ICI boilers and process heaters. This support is based on the findings of a study carried out by the International Paper Company and NCASI on a biomass boiler that was co-firing coal at the time of the study and was equipped with a wet scrubber for PM control. The results of the study showed that the response of the Hg CEMS could not be correlated with the EPA Method 29 measured mercury concentrations in the stack gas. NCASI is preparing a detailed report on this study which will be submitted to EPA under separate cover in response to this Reconsideration Proposal.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3505-A1, excerpt 4.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 93

Comment: We support EPA's decision not to require Hg CEMS on industrial boilers and process heaters. This support is based on the findings of a study carried out by the International Paper Company and NCASI on a biomass boiler that was co-firing coal at the time of the study and was equipped with a wet scrubber for PM control. The results of the study showed that the response of the Hg CEMS could not be correlated with the EPA Method 29-measured mercury concentrations in the stack gas. NCASI is preparing a detailed report on this study which will be submitted to EPA.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3505-A1, excerpt 4.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 77

Comment: We support EPA's decision not to require Hg CEMS on industrial boilers and process heaters. This support is based on the findings of a study carried out by the International Paper Company and NCASI on a biomass boiler that was co-firing coal at the time of the study and was equipped with a wet scrubber for PM control. The results of the study showed that the response of the Hg CEMS could not be correlated with the EPA Method 29-measured mercury concentrations in the stack gas. NCASI is preparing a detailed report on this study which will be submitted to EPA.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3505-A1, excerpt 4.

Commenter Name: Mary Sullivan Douglas

Commenter Affiliation: National Association of Clean Air Agencies (NACAA)

Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1

Comment Excerpt Number: 57

Comment: EPA has solicited comment on the use of continuous Hg monitors rather than fuel testing. NACAA supports this proposal; as discussed herein fuel sampling is insufficiently precise to monitor compliance at appropriate emission levels.

Response: The EPA thanks the commenter for their support.

Commenter Name: Bart Sponsellar

Commenter Affiliation: Wisconsin Department of Natural Resources

Document Control Number: EPA-HQ-OAR-2002-0058-3527-A2

Comment Excerpt Number: 25

Comment: The Department believes that monitoring of other operating parameters is not required when directly monitoring the pollutant of interest with a CMS.

Response: The EPA agrees with the commenter and has stated in the final rule in Section 63.7525(l)(8) that you are allowed to substitute the use of a mercury or a hydrogen chloride CEMS for the applicable fuel analysis, annual performance test, and operating limits specified in Table 4 to the subpart.

Commenter Name: Lorraine Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1
Comment Excerpt Number: 51

Comment: ACC requests that EPA amend the restriction found at § 63.7525(l)(8) that allows substitution of CEMS, but only if an add-on control to comply with the Hg or HCl emission limits is used. ACC sees no need for such a restriction. A source without add-on control should be able to control its fuel supply or feed rate such that it complies with the standards and demonstrates continuous compliance using a CEMS.

Response: The EPA agrees with the commenter and has stated in the final rule in Section 63.7525(l)(8) that you are allowed to substitute the use of a mercury or a hydrogen chloride CEMS for the applicable fuel analysis, annual performance test, and operating limits specified in Table 4 to the subpart.

Commenter Name: Steve Gossett
Commenter Affiliation: Eastman Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3669-A2
Comment Excerpt Number: 21

Comment: Comment Summary: The proposed CEMS alternatives for mercury and hydrogen chloride are appropriate and should be included in the final rule except that they should not be restricted to use of add-on controls.

EPA included this option at §63.7525(l) with further detailed requirements at §63.7540(a)(14) and (15). We note that while EPA does not mention it in the preamble, it is also proposing a similar option for use of HCl CEMS.

We support inclusion of both of these options. EPA has precedent for allowing use of these CEMS in the Utility MACT. Some facilities may select these options in order to obtain more operating flexibility and to better assure continuous compliance with the standards. We support the use of a 30-day rolling average to determine compliance.

Response: See the responses to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 51, and to comment EPA-HQ-OAR-2002-0058-3510-A1 excerpt 48 under the chapter SO₂ CEMS (HCl Alternative).

Commenter Name: Steve Gossett
Commenter Affiliation: Eastman Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3669-A2
Comment Excerpt Number: 22

Comment: The only request we have for change to the proposed provisions is the restriction found at §63.7525(1)(8) that allows substitution of CEMS only if you are using an add-on control to comply with the mercury or hydrogen chloride emission limits. We see no need for such a restriction. A source without add-on control should be able to control its fuel supply or feed rate such that it complies with the standards and demonstrates continuous compliance using a CEMS.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 51.

Commenter Name: Bart Sponsellar

Commenter Affiliation: Wisconsin Department of Natural Resources

Document Control Number: EPA-HQ-OAR-2002-0058-3527-A2

Comment Excerpt Number: 15

Comment: EPA is proposing to allow sources to use a Mercury (Hg) CEMs in place of the currently required periodic testing, fuel sampling analysis, and parametric monitoring. The Department supports adding this flexibility for demonstrating compliance. The Department asks EPA to consider an option where a source can continuously monitor Hg with a CMS or non-certified continuous monitoring option in conjunction with biennial stack testing and an appropriate level of fuel sampling. The Department believes a biennial stack test option should also apply to sources with activated carbon injection systems or other positive Hg control systems. The Department believes that a source should be subject to biennial stack testing instead of annual stack testing when the pollutant is continuously monitored by a CMS or parametric monitoring of control equipment which positively reduces emissions of the pollutant in question (metals, mercury, CO) for a pollutant which has been demonstrated by the source to correlate with the pollutant in question.

Response: The EPA appreciates the support of the commenter for the option of using an Hg CEMS for compliance monitoring. The commenter requests that the final rule include an additional option of using an Hg CEMS as a CPMS coupled with biennial stack testing and an appropriate level of fuel sampling to determine compliance. Though this is an interesting option that parallels the approach promulgated in the MATS rule where a PM CEMS may be used as a CPMS, EPA does not believe that we currently have sufficient background information nor adequate opportunity for public notice and comment to promulgate such an option. The affected facilities, however, always have the option to request alternative methods/approaches to demonstrating compliance under the provisions of 63.7(f).

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 76

Comment: EPA has proposed to allow HCl and Hg CEMS as an alternate to complying with fuel analysis or stack testing and continuous parameter monitoring. 76 Fed. Reg. 80,610. CIBO members support the flexibility provided by this option, as facilities that have these monitors installed should be able to take advantage of their use in order to comply with this rule and should not be required to perform additional stack testing or parameter monitoring. As

mentioned above, and for the reasons set forth in prior comments, emissions averaging with no 10% penalty should be allowed if CEMS are used.

Response: The EPA thanks the commenter for their support of flexible monitoring alternatives and we have included these in the final rule. Comments related to the discount factor for emissions averaging when using CEMS are out of scope since we have not reconsidered the emission averaging provision in this notice.

Commenter Name: Michael L. Krancer

Commenter Affiliation: Pennsylvania Department of Environmental Protection (DEP)

Document Control Number: EPA-HQ-OAR-2002-0058-3507-A1

Comment Excerpt Number: 9

Comment: In the reconsidered rule, the EPA has proposed the optional use of Hg CEMS for compliance demonstration and monitoring for units subject to Hg limits whose operators do not want to rely on periodic testing, fuel sampling analysis, and parametric monitoring.

The DEP believes this approach is reasonable and allows the operators an additional compliance option and operational flexibility.

Response: The EPA thanks the commenter for their support.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 91

Comment: EPA has proposed to allow HCl and Hg CEMS as an alternate to complying with fuel analysis or stack testing and continuous parameter monitoring. We support the flexibility provided by this option, as facilities that have these monitors installed should be able to take advantage of their use in order to comply with this rule and should not be required to perform additional stack testing or parameter monitoring.

Response: The EPA thanks the commenter for their support.

Commenter Name: Vickie Woods

Commenter Affiliation: Division of Air Quality, North Carolina Department of Environment and Natural Resources (NCDENR)

Document Control Number: EPA-HQ-OAR-2002-0058-3663-A2

Comment Excerpt Number: 10

Comment: Hg. Proposing option to use Hg CEMS for compliance demonstration and monitoring for units subject to Hg limits whose operators do not want to rely on periodic testing, fuel sampling analysis, and parameter monitoring.

NC DAQ concurs with EPA's proposed approach on this issue.

Response: The EPA thanks the commenter for their support.

Commenter Name: Douglas A. McWilliams

Commenter Affiliation: American Municipal Power

Document Control Number: EPA-HQ-OAR-2002-0058-3685-A2

Comment Excerpt Number: 47

Comment: EPA has included numerous compliance demonstration alternatives in the Proposed Rule. AMP appreciates EPA's efforts to provide flexibility to the regulated community and supports EPA's inclusion of the following optional compliance alternatives:

- Operation of Hg, HCl, and CO CEMS in lieu of stack testing

Response: The EPA thanks the commenter for their support.

11F. SO₂ CEMS (HCl Alternative)

Commenter Name: Steve Gossett

Commenter Affiliation: Eastman Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3669-A2

Comment Excerpt Number: 23

Comment: Comment Summary: Sulfur dioxide (SO₂) CEMS should be allowed for demonstrating continuous compliance with HCl emission limits.

We agree with EPA's conclusions that acid gas HAP control efficiencies would be better than SO₂ control efficiency (for a given acid gas control device) and that it should be possible to demonstrate a correlation between the two control efficiencies and then to rely on an SO₂ CEMS to demonstrate continuous compliance. EPA drew this same conclusion in the recently finalized Utility MACT and set alternative SO₂ emission limits.

In this case, we agree there is not enough information to set an alternative SO₂ limit that correlates with the HCl emission standard, such as was done in Utility MACT. One key difference is that the Utility MACT HCl emission limit (0.002 lb/mmBtu) is about ten times lower than the proposed Boiler MACT HCl limit for solid-fuel boilers.

Response: The commenter, as well as several other commenters, support the conclusion that acid gas HAP control efficiencies would be better than SO₂ control efficiency and, thus, the option of using measuring SO₂ as a surrogate for demonstrating compliance with the HCl emission limits. One commenter, EPA-HQ-OAR-2002-0058-3543-A1, excerpt 24, found in its emissions testing experience, that HCl is indeed more effectively controlled than SO₂ in wet FGD systems. Another commenter, EPA-HQ-OAR-2002-0058-3491-A1, excerpt 1, reported that HCl and SO₂ removal go hand in hand with dry sorbent injection and that based on test data it is well established that high levels of HCl removal are achieved with modest removals of SO₂.

We agree that there is not enough information to set an alternative SO₂ limit that correlates with the HCl emission standard, such as was done in MATS (i.e., Utility MACT). We agree, however, there is sufficient information and data to allow SO₂ CEMS as an alternation operating

limit for demonstrating continuous compliance with the HCl emission limits under certain conditions. This method of demonstrating continuous compliance would be allowed only on any unit that utilizes an acid-gas control technology including wet scrubber, dry scrubbers, and duct sorbent injection.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 96

Comment: We would suggest SO₂ continuous monitoring be allowed as a continuous parametric monitoring system (CPMS) and that the maximum 30-day rolling average SO₂ operating parameter limit be set during a 3-run performance test where HCl emissions are demonstrated to comply with the final HCl emission limit. This method of continuous compliance should be allowed on any unit that utilizes an acid-gas control technology including wet scrubber, dry scrubbers, and duct sorbent injection.

Response: We thank the commenter for their suggestion which limits the alternative compliance to only unit that utilizes an acid gas control technology. We agree that the operating should be a 30-day rolling average which is consistent with the averaging time for other operating limits and consistent with averaging time for units that are subject to the SO₂ limit in NSPS subpart Db. See response to comment EPA-HQ-OAR-2002-0058-3669-A2, excerpt 23 for further discussion on the approach being incorporated into the final rule.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 72

Comment: In the 2012 Reconsidered Boiler MACT Rule, EPA is soliciting comment on "the use of SO₂ CEMS for demonstrating continuous compliance with the HCl emission limits." 76 Fed. Reg. 80610. EPA has indicated that it is a "reasonable approach" to allow the use of SO₂ CEMS to demonstrate compliance with the HCl standard if there is a "correlation between SO₂ control and control of other acid gases emitted from each specific unit that chooses to use SO₂ CEMS." 76 Fed. Reg. 80610. As stated in our comments on the Proposed Boiler MACT Rule, SO₂ CEMS is a good indicator of HCl removal and EPA should allow its use in demonstrating compliance with the HCl standard.

A proposed approach to the use of SO₂ CEMS for demonstration of continuous compliance with the HCl limit is to determine the SO₂ emission rate (in lb/MMBTU) at the time of the HCl stack test for Boiler MACT compliance. Compliance with SO₂ emission rate determined during the HCl stack test is proposed to be calculated on a 30-day rolling average.

Response: See response to comment EPA-HQ-OAR-2002-0058-3669-A2, excerpt 23 and comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 96.

Commenter Name: Samuel H. Bruntz
Commenter Affiliation: Alcoa Power Generating, Inc.
Document Control Number: EPA-HQ-OAR-2002-0058-3755-A1
Comment Excerpt Number: 6

Comment: Proposed regulation 63.7520 (b) requires that performance tests must be conducted as specified in Table 5 for PM, HCl, and mercury. With respect to HCl, the requirement is to perform Method 26A emissions tests to demonstrate compliance with the proposed emission limit of 0.022lb./mmBtu, as specified in Table 2 of the proposed regulation.

Alcoa Warrick has 3 coal-fired industrial boilers that are subject to 40 CFR 60, Subpart Db with respect to SO₂ emissions, and must continuously monitor SO₂ removal performance across the wet FGD scrubbers on each boiler. Test data available to Alcoa Warrick to date indicates that when the SO₂ CEMS is reporting SO₂ removals above 95%, HCl emissions have been measured by EPA Method 26A to be non-detectable.

Alcoa Warrick suggests that EPA consider the concept of using SO₂ CEMS as a surrogate for HCl emissions. In order to implement this concept, Alcoa Warrick suggests that SO₂ removal measured during the initial EPA Method 26A compliance test for HCl become the parametric limit, if the initial Method 26A compliance test demonstrates compliance with the proposed limit. Thereafter, no further Method 26A tests would be necessary, because the SO₂ CEMS would be demonstrating continuous compliance.

Response: See response to comment EPA-HQ-OAR-2002-0058-3669-A2, excerpt 23.

Commenter Name: J. Michael Geers
Commenter Affiliation: Duke Energy
Document Control Number: EPA-HQ-OAR-2002-0058-3543-A1
Comment Excerpt Number: 24

Comment: Using Sulfur Dioxide (SO₂) CEMS for Demonstrating Continuous Compliance with HCl Emission Limits

EPA is requesting comment on adding an additional provision in the rule to allow for the use of SO₂ CEMS for demonstration of continuous compliance with the HCl emission limits for sources that are equipped with acid gas controls. Duke Energy strongly supports this concept and notes that EPA included similar provisions in the final Mercury and Toxics Standards rule. While the EPA states that it does not have enough information to propose specific requirements, it believes that a reasonable approach would be to allow for the use of SO₂ CEMS provided that the source demonstrates a correlation between SO₂ control and control of other acid gases emitted from each specific unit that chooses to use SO₂ CEMS. EPA expects that such a relationship would exist because the available add-on controls for acid gases would provide better control efficiencies for the acid gas HAP than for SO₂. As a result, demonstrating a level of SO₂ control using CEMS would provide assurance that the acid gas HAPs are being controlled. In its emissions testing experience, Duke Energy has found that HCl is indeed more effectively controlled than SO₂ in wet FGD systems. As a result Duke Energy recommends that EPA adopt in the final rule, an option for sources to establish a relationship between SO₂ and

HCl based on emissions testing. That testing would establish a maximum SO₂ emission rate, or minimum percent SO₂ removal rate that would demonstrate compliance with the HCl standard.

The source would then monitor and determine compliance using an SO₂ CEMS.

Response: See the responses to comments EPA-HQ-OAR-2002-0058-3669-A2, excerpt 23, EPA-HQ-OAR-2002-0058-3534-A1, excerpt 72, and EPA-HQ-OAR-2002-0058-3755-A1, excerpt 6.

Commenter Name: David Foerter

Commenter Affiliation: Institute of Clean Air Companies (ICAC)

Document Control Number: EPA-HQ-OAR-2002-0058-3491-A1

Comment Excerpt Number: 1

Comment: ICAC believes that the Industrial Commercial and Institutional (ICI) sector should be afforded the same, or even more, flexibility in meeting the final emission limitations as the utility sector has been afforded in the final Mercury and Air Toxics Standards (MATS) final rule (77 FR 9304-9513, February 16, 2012). One of those flexibilities is for EGUs that use flue gas desulfurization and SO₂ CEMs. Those units are allowed to use SO₂ as a surrogate for compliance with the HCl emission limitation. EPA is soliciting comment on the use of SO₂ CEMS for demonstrating continuous compliance with the hydrogen chloride (HCl) emission limit (80610/1).

Based on both test data and field trials it has been well established that high levels of HCl removal are achieved with modest removals of SO₂. From test data, the use of SO₂ as a surrogate for HCl removal is a reasonable approach. It has been well demonstrated that 30% to 40% SO₂ removal will result in very high removal levels of HCl that easily meet the Industrial Boiler (IB) MACT (Maximum Achievable Control Technology) standard of 0.022 lb/MMBtu. The SO₂ surrogate standard is 0.2 lb/MMBtu for the Utility MATS for a much lower HCl limit of 0.002 lb/MMBtu. Since the ICI Boiler MACT standard for HCl is much higher, we feel the EPA should consider a higher level for the SO₂ surrogate under the ICI Boiler MACT. We encourage EPA to analyze the data from this sector to determine a reasonable SO₂ surrogate standard.

HCl and SO₂ removal go hand in hand with dry sorbent injection and if HCl compliance must be demonstrated, the corresponding SO₂ removal could be considered a suitable substitute for continuous monitoring. The use of SO₂ CEMS then appears to be a very practical alternative to the more difficult HCl monitoring and should be an alternative. While the 0.2 lb/MMBtu SO₂ surrogate level in the Utility MATS could be adopted, there are reasonable arguments and data to support a higher surrogate level in the ICI Boiler MACT Rule.

Response: We thank the commenter for their support of affording the Industrial, Commercial, and Institutional (ICI) sector the same flexibility in meeting the emission limitations as the utility sector has been afforded in the MATS rule. We thank the commenter for providing support, based on both test data and field trials, that high levels of HCl removal are achieved with modest removals of SO₂ and that the use of SO₂ as a surrogate for HCl removal is a reasonable approach. See response to comment EPA-HQ-OAR-2002-0058-3669-A2, excerpt 23 for how this alternative will be incorporated into the final rule.

Commenter Name: Melvin E. Keener
Commenter Affiliation: Coalition for Responsible Waste Incineration (CRWI)
Document Control Number: EPA-HQ-OAR-2002-0058-3454-A1
Comment Excerpt Number: 19

Comment: Sulfur dioxide (SO₂) CEMS should be allowed for demonstrating continuous compliance with HCl emission limits.

EPA is soliciting comments on petitioner's request to allow use of SO₂ CEMS for demonstration of continuous compliance with the HCl emission limits for sources that are equipped with acid gas controls (76 Fed. Reg. at 80,610).

CRWI agrees with EPA's conclusions that acid gas HAP control efficiencies would be better than SO₂ control efficiency (for a given acid gas control device) and that it should be possible to demonstrate a correlation between the two control efficiencies and then to rely on an SO₂ CEMS to demonstrate continuous compliance. EPA drew this same conclusion in the recently finalized Utility MACT and set alternative SO₂ emission limits. We also agree there is not enough information to set an alternative SO₂ limit that correlates with the HCl emission standard, such as was done in Utility MACT.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3669-A2, excerpt 23.

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific LLC (GP)
Document Control Number: EPA-HQ-OAR-2002-0058-3465-A1
Comment Excerpt Number: 31

Comment: GP supports EPA providing an option in the rule to allow boilers equipped with SO₂ CEMS to use the CEMS for demonstrating continuous compliance with the HCl emission limits. The relationship between SO₂ and HCl could potentially be developed for particular sources. Factors such as stable fuel supplies or acid gas control systems would be factors a facility would need to evaluate to determine the usefulness of this option.

GP would urge EPA to consider allowing SO₂ monitoring as an option for demonstrating compliance with HCl standards.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3669-A2, excerpt 23.

Commenter Name: Michael L. Krancer
Commenter Affiliation: Pennsylvania Department of Environmental Protection (DEP)
Document Control Number: EPA-HQ-OAR-2002-0058-3507-A1
Comment Excerpt Number: 10

Comment: The EPA is soliciting comments on the use of SO₂ CEMS for demonstrating compliance with HCl limits after demonstrating a correlation between SO₂ control and control of other acid gases emitted from each unit.

The DEP believes that this approach is reasonable provided an appropriate correlation is established between the SO₂ control and the control of other acid gases. After a correlation is established, this would provide an additional, less burdensome compliance option.

Response: We thank the commenter for their support. See the response to comment EPA-HQ-OAR-2002-0058-3669-A2, excerpt 23.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 52

Comment: *USE OF SULFUR DIOXIDE (SO₂) CEMS FOR DEMONSTRATING CONTINUOUS COMPLIANCE WITH THE HCL EMISSION LIMITS*

ACC agrees with EPA's conclusions that acid gas HAP control efficiencies would be better than SO₂ control efficiency (for a given acid gas control device) and that it should be possible to demonstrate a correlation between the two control efficiencies and then to rely on an SO₂ CEMS to demonstrate continuous compliance. EPA drew this same conclusion in the recently finalized MATS rule and set alternative SO₂ emission limits.¹⁷

[Footnote 17: The MATS preamble at 77 Fed. Reg. 9367 states —For coal-fired EGUs, this final rule regulates HCl as a surrogate for acid gas HAP, with an alternate of SO₂ as a surrogate for acid gas HAP for coal-fired EGUs with FGD systems installed and operational...."]

Response: See the response to comment EPA-HQ-OAR-2002-0058-3669-A2, excerpt 23.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 53

Comment: *USE OF SULFUR DIOXIDE (SO₂) CEMS FOR DEMONSTRATING CONTINUOUS COMPLIANCE WITH THE HCL EMISSION LIMITS*

ACC agrees with EPA's conclusions that acid gas HAP control efficiencies would be better than SO₂ control efficiency (for a given acid gas control device) and that it should be possible to demonstrate a correlation between the two control efficiencies and then to rely on an SO₂ CEMS to demonstrate continuous compliance. EPA drew this same conclusion in the recently finalized MATS rule and set alternative SO₂ emission limits.¹⁷

[Footnote 17: The MATS preamble at 77 Fed. Reg. 9367 states "For coal-fired EGUs, this final rule regulates HCl as a surrogate for acid gas HAP, with an alternate of SO₂ as a surrogate for acid gas HAP for coal-fired EGUs with FGD systems installed and operational...."]

Response: See the response to comment EPA-HQ-OAR-2002-0058-3669-A2, excerpt 23.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 94

Comment: EPA is soliciting comment on allowing the use of SO₂ CEMS for demonstration of continuous compliance with the HCl emission limits for sources that are equipped with acid gas controls *76 Fed. Reg. 80610*.

We agree with EPA's conclusions that acid gas HAP control efficiencies would be better than SO₂ control efficiency (for a given acid gas control device) and that it should be possible to demonstrate a correlation between the two control efficiencies and then to rely on an SO₂ CEMS to demonstrate continuous compliance. EPA drew this same conclusion in the recently finalized MATS rule and set alternative SO₂ emission limits.⁴⁴

[Footnote 44: MATS preamble section V.C states "For coal-fired EGUs, this final rule regulates HCl as a surrogate for acid gas HAP, with an alternate of SO₂ as a surrogate for acid gas HAP for coal-fired EGUs with FGD systems installed and operational...."]

Response: See the response to comment EPA-HQ-OAR-2002-0058-3669-A2, excerpt 23.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 95

Comment: In this case, we agree there is not enough information to set an alternative SO₂ limit that correlates with the HCl emission standard, such as was done in Utility MACT. One key difference is that the Utility MACT HCl emission limit (0.002 lb/MMBtu) is about ten times lower than the proposed Boiler MACT HCl limit for solid-fuel boilers.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3669-A2, excerpt 23.

Commenter Name: Mary Sullivan Douglas

Commenter Affiliation: National Association of Clean Air Agencies (NACAA)

Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1

Comment Excerpt Number: 58

Comment: NACAA is supportive of EPA efforts to afford maximum flexibility to affected sources in demonstrating compliance, in order to allow lowest cost emission reductions and the best use of limited state and local resources. We agree that properly functioning SO₂ controls will also reduce HCl emissions and so chlorine levels can be correlated with HCl emissions in such units and in such instances. Sources with existing SO₂ monitors should not have to install separate HCl monitors. However, low sulfur concentration in fuels does not guarantee low chlorine levels in those fuels, especially in biomass fuels. NACAA does not support the use of continuous SO₂ monitors as a surrogate for HCl monitoring in units that do not have active SO₂ controls.

Response: We thank the commenter for their support in affording flexibility in demonstrating compliance. We agree that low sulfur concentration in fuels does not guarantee low chlorine levels in those fuels and, thus, we agree with the commenter that the use of continuous SO₂ monitors as a surrogate for HCl monitoring should not be allowed for units that do not have active SO₂ controls. See the response to comment EPA-HQ-OAR-2002-0058-3669-A2, excerpt 23 for further discussion.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 79

Comment: We take this opportunity to also request an alternative CPMS utilizing SO₂ continuous monitoring. On page 80610 of the reconsideration proposal for the Boiler MACT, EPA solicits comment on petitioners' request to allow use of SO₂ CEMS for demonstration of continuous compliance with the HCl emission limits for sources that are equipped with acid gas controls.

We agree with EPA's conclusions that acid gas HAP control efficiencies would be better than SO₂ control efficiency (for a given acid gas control device) and that it should be possible to demonstrate a correlation between the two control efficiencies and then to rely on an SO₂ CEMS to demonstrate continuous compliance. EPA drew this same conclusion in the recently finalized Utility MACT and set alternative SO₂ emission limits.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3669-A2, excerpt 23.

Commenter Name: Vickie Woods

Commenter Affiliation: Division of Air Quality, North Carolina Department of Environment and Natural Resources (NCDENR)

Document Control Number: EPA-HQ-OAR-2002-0058-3663-A2

Comment Excerpt Number: 11

Comment: SO₂. SO₂ CEMS for demonstrating continuous compliance with HCl emission limits provided source demonstrates correlation between SO₂ control and control of other acid gases.

NC DAQ concurs with EPA's proposed approach on this issue.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3669-A2, excerpt 23.

Commenter Name: David Foerter

Commenter Affiliation: Institute of Clean Air Companies (ICAC)

Document Control Number: EPA-HQ-OAR-2002-0058-3491-A1

Comment Excerpt Number: 2

Comment: Recent pilot plant tests conducted by a leading reagent supplier at an independent site incontrovertibly prove that dry injection of sodium bicarbonate or trona can achieve >99%

removal rates for HCl; and is able to meet the HCl limit in the Utility MATS and most certainly for the ICI Boiler MACT Rule. The tests effectively demonstrate the selectivity of sodium sorbents to remove HCl in a medium to high sulfur environment.

The pilot boiler tests were conducted at an independent site, the Energy & Environmental Research Center (EERC) facility at the University of North Dakota. Using coal from the Central Appalachian Basin (CAPP), sodium bicarbonate and trona were tested using both ESP and Baghouse to demonstrate that Dry Sorbent Injection with trona or sodium bicarbonate is able to meet the HCl limit (0.022 lb/MMBtu). Both sorbents were easily able to meet the required emissions levels. Depending on the particular application, one may be better than the other, but at least now it is clear that Dry Sodium Sorbent Injection is fully capable of reaching compliance.

Response: We thank the commenter for providing information and data from pilot plant tests that showed dry injection of sodium bicarbonate or trona can achieve >99% HCl removal and meets HCl limits.

Commenter Name: Melvin E. Keener

Commenter Affiliation: Coalition for Responsible Waste Incineration (CRWI)

Document Control Number: EPA-HQ-OAR-2002-0058-3454-A1

Comment Excerpt Number: 20

Comment: We suggest SO₂ continuous monitoring be allowed as a continuous parametric monitoring system (CPMS) and that the maximum 30 day rolling average SO₂ operating parameter limit be set during a 3-run performance test where HCl emissions are demonstrated to comply with the final HCl emission limit. This method of continuous compliance should be allowed on any unit that utilizes an acid-gas control technology including wet scrubber, dry scrubbers, and duct sorbent injection.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 96.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 54

Comment: ACC suggests SO₂ continuous monitoring be allowed as a CPMS, and that the maximum 30-day rolling average SO₂ operating parameter limit be set during a 3-run performance test where HCl emissions are demonstrated to comply with the final HCl emission limit. This method of continuous compliance should be allowed on any unit that utilizes an acid-gas control technology including wet scrubber, dry scrubbers, and duct sorbent injection.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 96.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 78

Comment: Parametric monitoring provisions are needed for acid gas controls including dry sorbent injection. Also, an option to use SO₂ emission rate and a SO₂ continuous monitoring system correlated to HCl emissions is needed. On page 80464 of the reconsideration proposal preamble, EPA, in response to Petitioners' requests, is soliciting comment on the need to specify monitoring provisions for dry sorbent injection and any other control devices not already addressed.

Dry sorbent injection or spray dryer absorbers (using hydrated lime) are two technologies that could be used to reduce HCl and/or SO₂ emissions. We suggest a similar approach as in the Boiler MACT – see Table 7 on page 80668 of the December 23, 2011 Federal Register.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 96.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 80

Comment: In this case, we agree there is not enough information to set an alternative SO₂ limit that correlates with the HCl emission standard, such as was done in Utility MATS. One key difference is that the Utility MATS HCl emission limit (0.002 lb/mmBtu) is about ten times lower than the proposed Boiler MACT HCl limit for solid-fuel boilers (0.022 lb/mmBtu).

We would suggest in both the Boiler MACT and the CISWI rule that SO₂ continuous monitoring be allowed as a continuous parametric monitoring system (CPMS) and that the maximum 30 day rolling average SO₂ operating parameter limit to be set during a 3-run performance test where HCl emissions are demonstrated to comply with the final HCl emission limit. This method of continuous compliance should be allowed on any unit that utilizes an acid-gas control technology including wet scrubber, dry scrubbers, and duct sorbent injection.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 96.

Commenter Name: Robin Mills Ridgway

Commenter Affiliation: Purdue University

Document Control Number: EPA-HQ-OAR-2002-0058-3668-A2

Comment Excerpt Number: 16

Comment: In the 2012 Reconsidered Boiler MACT Rule, EPA is soliciting comment on "the use of SO₂ CEMS for demonstrating continuous compliance with the HCl emission limits." (76 FR 80610). EPA has indicated that it is a "reasonable approach" to allow the use of SO₂ CEMS to demonstrate compliance with the HCl standard if there is a "correlation between SO₂ control and control of other acid gases emitted from each specific unit that chooses to use SO₂ CEMS." (76 FR 80610). Purdue believes SO₂ CEMS is a good indicator of HCl removal and EPA should allow its use in demonstrating continuous compliance with the HCl standard.

EPA is soliciting comment on allowing the use of SO₂ CEMS for demonstration of continuous compliance with the HCl emission limits for sources that are equipped with acid gas controls (see 76 Fed.Reg. 80610).

Purdue suggests SO₂ continuous monitoring be allowed as a form of continuous parametric monitoring system (CPMS) and that the maximum 30 day rolling average SO₂ operating parameter limit to be set during a 3-run performance test where HCl emissions are demonstrated to comply with the final HCl emission limit. This method of continuous compliance should be allowed on any unit that utilizes an acid-gas control technology including wet scrubber, dry scrubbers, limestone sorbent in a CFB, and in duct sorbent injection.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 96.

Commenter Name: Steve Gossett

Commenter Affiliation: Eastman Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3669-A2

Comment Excerpt Number: 24

Comment: We suggest EPA allow SO₂ continuous monitoring as a continuous parametric monitoring system (CPMS) and that the maximum 30-day rolling average SO₂ operating parameter limit be set during a 3-run performance test where HCl emissions are demonstrated to comply with the final HCl emission limit. This continuous compliance demonstration method should be allowed on any unit that utilizes an acid- gas control technology including wet scrubbers, dry scrubbers, co-firing of natural gas, conversion to natural gas, and duct sorbent injection.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 96.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 73

Comment: In the Final Boiler MACT Rule, EPA required continuous monitoring of sorbent injection for continuous compliance purposes. 76 Fed. Reg. 15,615. In addition to the comment below, CIBO asks that EPA confirm that the use of limestone for SO₂ control in a CFB is a form of sorbent injection and could be included in this compliance strategy. As stated in our comments on the Proposed Boiler MACT Rule, which were filed on August 20, 2010, monitoring sorbent injection rates is problematic and unreasonable. Although the re-proposed rule improved on the proposed Boiler MACT by allowing scaling of injection rate to account for load changes, in some applications this linearization of a system that is not linear in nature causes not only a potentially large amount of sorbent to be wasted but in the case of the CFB utilizing limestone in the furnace for SO₂ control, will cause operational issue for the boiler itself. CIBO suggests that alternative methodologies be considered, such as tracking of the calcium to sulfur ratio of the fuel and the sorbent. This approach allows the source to more closely tune the sorbent injection to the fuel quality and is based upon the presumption that So₂ control correlates to HCl control.

Response: We agree that use of limestone in an CFB is a form of sorbent injection for SO₂ control and have revised the definition of "Minimum sorbent injection rate" to also mean the calcium to sulfur ratio for fluidized bed units.

Commenter Name: Samuel H. Bruntz
Commenter Affiliation: Alcoa Power Generating, Inc.
Document Control Number: EPA-HQ-OAR-2002-0058-3755-A1
Comment Excerpt Number: 7

Comment: Alcoa~ Warrick recommends the following amendments to Table 2, Table 4, and Table 8 that would incorporate its "SO₂ as HCl surrogate") suggestion:

[See page 4 of submittal for Table of language provided by the commenter]

Response: See response to comment EPA-HQ-OAR-2002-0058-3669-A2, excerpt 23 for discussion on how SO₂ is being used to demonstrate compliance with the HCl emission limits.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1
Comment Excerpt Number: 81

Comment: If this option is incorporated into the final rule, we request that the SO₂ CEMS be allowed to select either Part 60 or Part 75 for compliance procedures as many of the existing SO₂ CEMS already use Part 75 quality assurance procedures.

Response: The compliance procedures for the SO₂ CEMS option that has been incorporated into the final rule requires the CEMS to be operated according to part 75.

Commenter Name: Melvin E. Keener
Commenter Affiliation: Coalition for Responsible Waste Incineration (CRWI)
Document Control Number: EPA-HQ-OAR-2002-0058-3454-A1
Comment Excerpt Number: 21

Comment: If this option is incorporated into the final rule, we request that the SO₂ CEMS be allowed to select either Part 60 or Part 75 for compliance procedures as many of the existing SO₂ CEMS already use Part 75 quality assurance procedures.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 81.

Commenter Name: Steve Gossett
Commenter Affiliation: Eastman Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3669-A2
Comment Excerpt Number: 25

Comment: If this option is incorporated into the final rule, we request that the SO₂ CEMS be allowed to select either Part 60 or Part 75 for compliance procedures as many of the existing SO₂ CEMS already use Part 75 quality assurance procedures.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 81.

Commenter Name: Bart Sponsellar

Commenter Affiliation: Wisconsin Department of Natural Resources

Document Control Number: EPA-HQ-OAR-2002-0058-3527-A2

Comment Excerpt Number: 16

Comment: EPA is proposing to allow continuous CEMs monitoring of SO₂ as a surrogate for demonstrating compliance with HCL emission limitations if the source establishes a positive correlation between the control of SO₂ and HCL (acid gases). The Department supports this compliance demonstration option for HCL. The Department also believes that with a SO₂ CMS system (non-certified) that the source be allowed to perform compliance stack testing on a biennial schedule. The Department believes that a source should be subject to biennial stack testing instead of annual stack testing when the pollutant is continuously monitored by a CMS or parametric monitoring of control equipment which positively reduces emissions of the pollutant in question (metals, mercury, CO) for a pollutant which has been demonstrated by the source to correlate with the pollutant in question.

Response: We thank the commenter for their support. Provisions for reduced performance testing frequency have been added to the final rule that are based on the level of the measured emissions.

Commenter Name: Samuel H. Bruntz

Commenter Affiliation: Alcoa Power Generating, Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3755-A1

Comment Excerpt Number: 5

Comment: Alcoa - Warrick supports the position that EPA has expressed in proposed regulation 63.7525 (1)(8) for HCl and mercury, i.e. if add-on control equipment is being used for these pollutants, CEMS can be substituted for the fuel analysis, annual performance test requirements, and Table 4 operating requirements. Alcoa- Warrick suggests that the relief provided by 63.7525 (1)(8) be expanded to include SO₂ CEMS acting as surrogates for HCl, and PM-CEMS. Accordingly, Alcoa-Warrick suggests that 63.7525 (1)(8) be amended-as follows:

If you are using an add-on control to comply with the *PM*, mercury or hydrogen chloride emission limit, you are allowed to substitute the use of the mercury ~~or~~ hydrogen chloride CEMS, *SO₂ CEMS as surrogate for HCl, or PM-CEMS* for the applicable fuel analysis, annual performance test, and operating limits specified in Table 4 to this subpart to demonstrate compliance with the *PM*, mercury, or hydrogen chloride emissions limit.

Response: We agree with the commenter's suggestion and 63.7525(1)(8) has been revised to allow the use of a SO₂ CEMS to demonstrate compliance with the HCl emission limit.

Commenter Name: Lorraine Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1
Comment Excerpt Number: 48

Comment: EPA solicited comment in the 2010 Proposed Boiler Rule on its inclusion of an option to use Hg CEMS in lieu of periodic testing, fuel sampling analysis, and parameter monitoring. EPA included this option at § 63.7525(l) with further detailed requirements at § 63.7540(a)(14) and (15). ACC notes that while EPA does not mention it in the preamble to the 2010 Proposed Boiler Rule, it is also proposing a similar option for use of HCl CEMS in response to petitioners' requests.

ACC supports the flexibility provided by this proposed option, as facilities that have these monitors installed should be able to take advantage of their use in order to comply with this rule and should not be required to perform additional stack testing or parameter monitoring. Some facilities may select these options in order to obtain more operating flexibility and to better assure continuous compliance with the standards. EPA has precedent for allowing use of these CEMS as it included this provision in the MATS.

Response: The EPA thanks the commenter for their support.

11G. Averaging Times for Monitored Pollutants

Commenter Name: Paul Noe
Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.
Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1
Comment Excerpt Number: 106

Comment: We support EPA's determination that a 30-day rolling average for parameter monitoring and compliance with operating limits is appropriate for this rule. A longer averaging time for operating parameters is appropriate, because the standards apply over-all operating conditions, and operating conditions of industrial boilers can be highly variable, especially when fuel mix and load change. The operating parameter ranges will be established using test data obtained at one steady state operating condition, so a 30-day averaging period allows for some fluctuations that will occur over the range of operating conditions. EPA is correct in pointing out that variability outside the operator's control such as fuel content, seasonal factors, load cycling, and infrequent hours of needed operation give cause to use a longer averaging period (76 Fed. Reg. 80610).

Response: We thanks the commenter for their support of the 30-day rolling average period for the operating limits. However, the commenter provided no information or data to support its assertion that a longer averaging time is appropriate.

Commenter Name: Dakota Gasification Company Great Plains Synfuels Plant
Commenter Affiliation: David W. Peightal

Document Control Number: EPA-HQ-OAR-2002-0058-3424

Comment Excerpt Number: 11

Comment: DGC agrees with EPA's Averaging Times of a 30-day rolling average for parameter monitoring and demonstration of continuous compliance with operating limits.

Response: The EPA thanks the commenter for their support.

Commenter Name: Russell A. Wozniak

Commenter Affiliation: The Dow Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3449-A1

Comment Excerpt Number: 18

Comment: The proposed rule changes the control device parameter monitoring data averaging period for particulate matter wet scrubbers and hydrogen chloride wet scrubbers from 12-hour block averages to 30-day rolling averages. For fabric filters used to control particulate matter, the proposed rule added an option of maintaining opacity less than 10% (daily block average) and amended provisions for use of bag leak detection system to limit alarms to less than 5% of the operating time during each 6-month operating period.

Dow supports the change in monitoring data averaging time to 30-day rolling averages for PM wet scrubbers and HCl wet scrubbers. As discussed by EPA's comments regarding the proposed change, some variation in combustion unit control occurs during normal day-to-day activities (e.g. changes in fuel characteristics and load cycling). Since scrubber system design takes in to account varying stream flow characteristics, a brief excursion from an operating limit based on a point in time performance test would not result in a significant emissions change. The proposed 30-day rolling average provides a reliable method for demonstrating that the control systems are being properly operated and maintained.

Response: The EPA thanks the commenter for their support.

Commenter Name: Michael D. Wendorf

Commenter Affiliation: FMC Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3453-A1

Comment Excerpt Number: 5

Comment: A 30-day rolling averaging time for parameter monitoring and compliance with operating limits is a much better metric for demonstration of compliance than the 12-hour block averages in the final rule. A 30-day rolling average is consistent with averaging periods for boiler compliance in NSPS rules and new data points can be readily adapted into existing data acquisition systems.

Response: The EPA thanks the commenter for their support.

Commenter Name: Claudia M. O'Brien, Latham & Watkins LLP

Commenter Affiliation: JELD-WEN, inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3485-A1

Comment Excerpt Number: 6

Comment: In the Boiler MACT reconsideration, EPA has proposed to adopt a 30-day rolling average rather than the 12-hour block averages for parametric monitoring and continuous compliance with operation limits adopted in the final rule "to account for" variability in fuel content, seasonal factors, load cycling, etc. JELD-WEN supports this change, which properly reflects the significant variability in operating conditions that industrial boilers encounter as a result of their role in manufacturing facilities. Industrial boilers are of much smaller scale than utility boilers and must respond rapidly to changing load demands, which increases the variability.

Response: The EPA thanks the commenter for their support.

Commenter Name: Kevin G. Desharnais, Attorney, Mayer Brown LLP

Commenter Affiliation: United States Sugar Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3496-A1

Comment Excerpt Number: 11

Comment: As referenced above, the Reconsideration Proposal includes a 30-day rolling average for parameter monitoring and demonstrating compliance with a unit's operating limits, rather than the 12-hour rolling average included in the Final Rule. US Sugar supports this change as a more appropriate averaging period, particularly in the case of bagasse-fueled boilers, given the variable nature of bagasse as a fuel source.

Response: The EPA thanks the commenter for their support.

Commenter Name: Jessica Bridges

Commenter Affiliation: United States Clean Heat & Power Association (USCHPA)

Document Control Number: EPA-HQ-OAR-2002-0058-3501-A1

Comment Excerpt Number: 6

Comment: The EPA has determined that the 30-day rolling average for parameter monitoring and demonstration of continuous compliance with operating limits is appropriate for this rule. From review of studies the EPA expects that variability of long term emissions averaging will be about half that represented by the short term testing proposed in the Final Rule (12-hour block). We agree that using the 30-day rolling average will reduce overall variability.

Response: The EPA thanks the commenter for their support.

Commenter Name: Timothy Serie

Commenter Affiliation: American Coatings Association (ACA)

Document Control Number: EPA-HQ-OAR-2002-0058-3502-A1

Comment Excerpt Number: 8

Comment: ACA generally supports the following proposed changes in the Boiler MACT rule:

Change to the use of a 30-day rolling average for parameter monitoring and demonstration of continuous compliance with operating limits

Response: The EPA thanks the commenter for their support.

Commenter Name: Michael L. Krancer

Commenter Affiliation: Pennsylvania Department of Environmental Protection (DEP)

Document Control Number: EPA-HQ-OAR-2002-0058-3507-A1

Comment Excerpt Number: 11

Comment: The EPA has proposed a 30-day rolling average for parameter monitoring and demonstration of continuous compliance with operating limits. This is a change from the final rule, which included 12-hour block averages that corresponded to the expected length of the longest duration 3-run emission test that was required to determine initial compliance with emission limits.

The DEP agrees with the EPA that this approach would alleviate concerns of variability outside the operators control such as fuel content, seasonal variability, load cycling, and infrequent hours of needed operation by applying a long-term average for establishing compliance.

Response: The EPA thanks the commenter for their support.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 47

Comment: ACC supports the use of a 30-day rolling average to determine compliance with Hg or HCl CEMS.

Response: The EPA thanks the commenter for their support.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 103

Comment: The industrial boilers and process heaters that will be subject to this rule often burn multiple types of fuels and are subject to frequent load swings. Therefore, the emissions from these units vary over the course of a day, depending on the fuel burned and the required production. EPA acknowledged during the Phase 2 ICR test program that emissions from industrial boilers and process heaters are variable by requesting multi-year historical stack test data and conducting 30- day fuel and emissions monitoring studies.

The court reviewing the Brick MACT authorized EPA to consider intra-unit variability and EPA's work on the Hazardous Waste Combustion MACT confirmed the importance of considering variability. Therefore, we believe it is inappropriate for EPA to set limits under the

Boiler MACT that cannot be met consistently by a top performing unit overall operating conditions. One way to consider a unit's variability in emissions is to set a longer averaging time for compliance with an emission limit.

There are factors beyond the boiler operator's control that can cause emissions to vary over a period of days, not hours. For example, the weather will impact moisture content of solid fuels, which will affect how the fuels combust over a period of days. For all types of boilers, the pollutant content of the fuel will vary over a period of days, as evidenced by the range of results obtained during the 30-day fuel sampling required by EPA for many ICR Phase 2 participants. Therefore, we support a 30-day rolling average period to account for operational and emissions variability.

Response: The EPA thanks the commenter for their support.

Commenter Name: John M. Cullen

Commenter Affiliation: Masco Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3661-A2

Comment Excerpt Number: 7

Comment: Masco supports the proposed 30-day rolling average times for parameter monitoring. Such averaging appropriately accounts for the fact that monitoring occurs over all operating conditions and that such operating conditions for industrial boilers are highly variable.

Response: The EPA thanks the commenter for their support.

Commenter Name: Vickie Woods

Commenter Affiliation: Division of Air Quality, North Carolina Department of Environment and Natural Resources (NCDENR)

Document Control Number: EPA-HQ-OAR-2002-0058-3663-A2

Comment Excerpt Number: 13

Comment: Averaging Times. EPA proposed 30-day rolling average for parameter monitoring and continuous compliance demonstration with operating limits. This would be a change from the final rule, which included 12-1u- block averages corresponding to expected length of longest duration 3-run emission test.

NC DAQ concurs with the 30-day rolling average for parametric monitoring using the most stringent values associated with the operation of the control equipment during performance testing. While NC DAQ recognizes that some parameters measured during performance testing might represent less variability than typical day-to-day operation, with sufficient EPA provided guidance in the future and data we believe that an operations and performance "envelope" can be established.

Response: The EPA thanks the commenter for their support.

Commenter Name: Steve Gossett

Commenter Affiliation: Eastman Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3669-A2

Comment Excerpt Number: 26

Comment: Comment Summary: EPA's proposed changes to a 30-day rolling average for parameter monitoring are appropriate.

Discussion: EPA's discussion of this issue is found on page 80610 of the preamble to the reconsideration proposal. We fully agree and support EPA's reasoning for this change. This proposal will provide needed operational flexibility. The previous 12-hour block averaging periods would have likely caused operators to consider shutdown of units that had some bobble or short term problem with a parameter in an attempt to avoid a potential permit deviation. These shutdowns and restarts would have resulted in more impact on the environment and the plant operation. A 30-day rolling average will allow operators to intervene and correct a problem without shutting down. We agree with EPA that major issues such as ESP transformer failure will show up in a 30-day rolling average and prevent continued operation with malfunctioning control equipment.

Response: The EPA thanks the commenter for their support.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 98

Comment: Changing operating parameter averaging times from 12 hour to 30 day averages is appropriate and will help adjust for the operating variability that real life operations experience versus the steady state operations during a performance test.

Performance tests are done at very controlled conditions. Typically units are set at a particular high firing rate, feed rates and compositions are held constant, and the unit's air to fuel ratio optimized and held fixed. Where controls are in place, this steady boiler or process heater operation allows the control operating parameters to be optimized and held steady. Furthermore, weather conditions, which can have a significant impact on combustion and control operations, change relatively little over a performance test time period. In the real world, fuel rates and compositions vary, weather conditions vary, and even very well controlled units and control devices go through combustion efficiency and control parameter swings. Longer averaging times for monitored parameters correct for much of this variability and will thus reduce the occurrence of deviations due to nothing other than attempting to match real life operations to the highly controlled, short term operations associated with performance testing. Eliminating deviations that reflect real control device variability, but which are unlikely to reflect significant HAP emission effects, will reduce burdens on both sources and regulators and allow both to focus on events where there are real emission impacts. Thus, we believe this change is entirely justified and appropriate and should be finalized.

Response: The EPA thanks the commenter for their support.

Commenter Name: Douglas A. McWilliams
Commenter Affiliation: American Municipal Power
Document Control Number: EPA-HQ-OAR-2002-0058-3685-A2
Comment Excerpt Number: 36

Comment: Regardless how EPA characterizes the enforceability of operating limits in the final rule, however, AMP supports a 30-day rolling averaging period for all operating parameters (including load and oxygen parameters). Operating conditions of industrial boilers can be highly variable, particularly for municipal utility boilers that may alter load frequently to account for fluctuating demand requirements. Operating parameters will be established using test data from a single steady-state operating period, and the parameter ranges established during this test are unlikely to be representative of the parametric values occurring over a range of operating conditions. Changes in fuel content and seasonal factors can also impact source variability. An extended averaging period helps accommodate some of this variability.

Response: The EPA thanks the commenter for their support.

Commenter Name: Lorraine Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1
Comment Excerpt Number: 57

Comment: There are factors beyond the boiler operator's control that can cause emissions to vary over a period of days, not hours. For example, the weather will impact moisture content of solid fuels, which will affect how the fuels combust over a period of days. For all types of boilers, the pollutant content of the fuel will vary over a period of days, as evidenced by the range of results obtained during the 30-day fuel sampling required by EPA for many ICR Phase 2 participants. Therefore, ACC supports a 30-day rolling average period to account for operational and emissions variability.

Response: The EPA thanks the commenter for their support.

Commenter Name: Paul Noe
Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.
Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1
Comment Excerpt Number: 108

Comment: Table 4 should specify a 30-day average for the Oxygen Analyzer System. The same reasons for providing a 30-day averaging period for control device operating parameters apply to the oxygen concentration measurement, especially for boilers where steam demand varies, resulting in load swings and variations in combustion conditions. The way the requirement is currently written implies that the oxygen concentration limitation is instantaneous. As startup is currently limited to conditions less than 25 percent load, this requirement may be impossible to meet without an averaging period, as not all boilers are stable at 25 percent load. We note that in Tables 3 and 7 of the Boiler GACT rule, the O₂ monitoring requirement does have a 30-day averaging period specified.

Response: We agree with the commenter that Table 4 should specify a 30-day average. This change has been made to Table 4 to be consistent with item 9(c) in Table 8 which state how continuous compliance is to be demonstrated.

Commenter Name: Russell A. Wozniak

Commenter Affiliation: The Dow Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3449-A1

Comment Excerpt Number: 16

Comment: The requirement that an oxygen trim system control the oxygen to a level established according to Table 4 should be adjusted to provide for a longer averaging time such as a 30 day average similar to other operating limits in Table 4 and similar to EPA's GACT rule. At a minimum, element #8 of EPA's proposed Table 4 should be revised as follows:

For boilers and process heaters subject to a carbon monoxide emission limit that demonstrates compliance with an O2 analyzer system as specified in 63.7525(a), maintain the 30-day rolling average oxygen level such that it is not below the lowest hourly average oxygen concentration measured during the most recent CO performance test.

Such a change would also be consistent with element 9.c. of Table 8 of this rule which requires that one maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen level measured during the most recent carbon monoxide performance test.

Response: For response to the request for compliance with oxygen limits to be determined on a 30-day rolling average, please see comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 108.

Commenter Name: Lee Zeugin and Lauren Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1

Comment Excerpt Number: 33

Comment: EPA proposes to address concerns about variability in control device parameters by lengthening the rolling averaging period for the parameter operating limits from 12 hours to 30 days. 76 Fed. Reg. at 80,610/2-3 and Proposed and Tables 4 and 8. Although a longer averaging period might smooth out some of the normal variability, and therefore would be an improvement over the current rule, EPA's proposal does not address the fundamental flaws in using the chosen parameters to set enforceable operating limits. Averaging periods alone cannot address the fact that the required parameters simply are not well correlated with emissions. Because EPA has never responded to UARG's prior comments on this point, UARG requests that EPA consider and respond to these comments in the context of determining how to address operating and control device variability in the final rule.

Response: We agree that the most direct means of ensuring compliance with emission limits is the use of continuous emission monitoring systems (CEMS). However, we consider other options when CEMS are not available or when the impacts of including such requirements are considered unreasonable. When monitoring options other than CEMS are considered, it is often necessary for us to balance more reasonable costs against the quality or accuracy of the actual

emissions monitoring data. Although monitoring of operating parameters cannot provide a direct measurement of emissions, it is often a suitable substitute for CEMS. The information provided can be used to ensure that air pollution control equipment is operating properly. Because the parameter requirements are calibrated during the initial and annual stack tests, they provide a reasonable surrogate for direct monitoring of emissions. This information reasonably assures the public that the reductions envisioned by the proposed rule are being achieved.

Commenter Name: J. Michael Geers

Commenter Affiliation: Duke Energy

Document Control Number: EPA-HQ-OAR-2002-0058-3543-A1

Comment Excerpt Number: 19

Comment: In the Limited Instances where Operating Limits are Necessary, it is Appropriate for EPA to Increase Averaging Times From 12 Hours to 30 Days. The EPA has determined that a 30-day rolling average for parameter monitoring and demonstration of continuous compliance with operating limits is appropriate for this rule. This is a change from the March 21, 2011 final rule, which generally included 12- hour block averages that corresponded to the expected length of the longest duration 3- run emission test that was required to demonstrate initial compliance with the emission limits. To the extent that operating limits are even appropriate for this rule, Duke Energy supports the change to longer averaging times. The operating limits established through performance testing required by this rule are based on short term, steady state conditions. In its information collection, EPA did not collect sufficient data to characterize the effects of changing load and other operating conditions. These changes can cause short term disruptions to various operating parameters and the longer averaging times will ideally smooth out these differences. Never the less as Duke Energy has indicated in other portions of these comments, EPA's proposed operating parameters generally are not accurate indicators of HAP control.

Response: The EPA thanks the commenter for their support of longer averaging times. For a response to the claim that the proposed operating parameters are not accurate indicators of HAP control, please see comment EPA-HQ-OAR-2002-0058-3500-A1, excerpt 33.

Commenter Name: David A. Buff, Golder Associates Inc.

Commenter Affiliation: Florida Sugar Industry (FSI)

Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1

Comment Excerpt Number: 14

Comment: The FSI respectfully requests that EPA set the O₂ limit for hybrid suspension grate boilers based on a 12-month rolling average. EPA has recognized the unique nature of hybrid suspension grate (bagasse) boilers, and EPA has recognized how the unique features of these boilers affect O₂ levels. In prior submittals to EPA², the FSI has demonstrated that hybrid suspension grate boilers are inextricably tied to the sugar production process. The sugar mill boilers experience significant swings in excess air and oxygen levels because of changes in sugarcane quality (i.e., fuel quality) during the crop season, upsets in the sugar mill, changes in the boiler load, and other factors. These factors not only upset the operation of the boilers, but they also are beyond the control of the boiler operators and the sugar mill operators. Upsets also

can occur in the bagasse feed systems due to plugging of the boiler fuel feeders, fuel piling up on the boiler grates (e.g., due to wet fuel or cold spots in the boiler), and other factors. All of these factors can cause routine, significant swings in the boiler's O2 levels and thus make it difficult to meet an O2 limit based on a 30-day rolling average.

[Footnote]

(2) Florida Sugar Industry's Additional Information in Support of Reconsideration and Amendment of NESHAP For Industrial Boilers, Docket ID No. EPA-HQ-OR-2002-0058. Submitted by Golder Associates Inc, July 15, 2011.

Response: We do not disagree that sugar mill boilers experience significant swings in excess air and oxygen levels because of changes in fuel quality, upsets in the sugar mill, changes in boiler load, and other factors. However, these are the same factors that affect boilers in the other subcategories. We realize that these factors can cause routine, significant swings in the boiler's O2 levels which is why the oxygen operating limit is based on a 30-day average. The commenter has not provided an analysis to support this request.

Commenter Name: David A. Buff, Golder Associates Inc.

Commenter Affiliation: Florida Sugar Industry (FSI)

Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1

Comment Excerpt Number: 15

Comment: The FSI has analyzed the continuous O2 data from the only FSI boiler that is equipped with a certified O2 monitor (U.S. Sugar Company's Boiler No. 8). This FSI boiler was designed to comply with the 2004 Boiler MACT standards for new sources. The FSI has used the data from Boiler No. 8 to evaluate the trends in boiler O2 levels, as measured at the stack. A plot of O2 data over a 3-year period is shown in Figures B-1 and B-2 of Appendix B – "O2 Data for New Bagasse Boiler".

The data show that the 30-day rolling average for O2 varied from about 7.5 percent to about 11.5 percent and thus there was a significant (50%) swing from the highest 30-day rolling average to the lowest 30-day rolling average. The highest O2 levels are experienced at the beginning of each crop season, when "take out" sugarcane is being processed in the sugar mill. Take out cane is of lower quality, requiring more excess air to combust. As the crop season progresses over the next 4 to 6 months, the sugarcane quality improves and less excess air is required, resulting in decreasing O2 levels. In contrast, the 12-month rolling average is rather stable over the course of the crop season, varying from only 8.2 percent to 8.7 percent over the course of three years.

Response: For response to the request for oxygen limits for hybrid suspension/grate units to be based on a 12-month rolling average, please see comment EPA-HQ-OAR-2002-0058-3504-A1, excerpt 14.

Commenter Name: David A. Buff, Golder Associates Inc.

Commenter Affiliation: Florida Sugar Industry (FSI)

Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1

Comment Excerpt Number: 26

Comment: The FSI agrees with EPA that a longer averaging time is necessary for demonstrating compliance with the EPA's proposed operating parameters. A longer averaging time for operating parameters is appropriate because the EPA standards apply to all operating conditions, and a longer timeframe will help account for variability in a boiler's operations. This issue is especially important to the FSI because the operating conditions for bagasse boilers can be highly variable, especially when there are fluctuations in the boiler's steam load, fuel (e.g., moisture content), fuel mix (i.e., differing varieties of sugarcane), and other factors that are beyond the control of the operator. FSI has presented a substantial amount of evidence to EPA demonstrating that the operation of bagasse-fired boilers is extremely variable because the boilers are interconnected with and intrinsically tied to the sugar mill. By comparison, the operating parameters will be established by using test data that are obtained during one steady-state operating condition. A 30-day averaging period allows for some of the fluctuations that will occur over the normal range of operating conditions.

For these reasons, the FSI supports the use of a 30-day rolling average for demonstrating compliance with the operating parameters, except for O₂, which requires a longer averaging time because O₂ tends to be much more variable than other operating parameters. The averaging time for O₂ is discussed in paragraph 5(b), above.

Response: The EPA thanks the commenter for their support of 30-day rolling averages for parameters other than oxygen. For response to request for oxygen limits for hybrid suspension/grate units to be based on a 12-month rolling average, please see comment EPA-HQ-OAR-2002-0058-3504-A1, excerpt 14.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 56

Comment: *AVERAGING TIMES*

The ICI boilers and process heaters subject to the Final Boiler Rule often burn multiple types of fuels and are subject to frequent load swings. Therefore, the emissions from these units vary over the course of a day, depending on the fuel burned and the required production. EPA implicitly acknowledged during the Phase 2 ICR test program that emissions from ICI boilers and process heaters are variable by requesting multi-year historical stack test data and conducting 30-day fuel and emissions monitoring studies.

The court reviewing the Brick MACT (40 CFR 63, Subpart JJJJ - NESHAP for Brick and Structural Clay Products Manufacturing) confirmed EPA's authority to consider intra-unit variability,²⁰ and EPA's Hazardous Waste Combustor MACT (40 CFR 63, Subpart EEE, NESHAP for Hazardous Waste Combustors) confirmed the importance of considering variability.²¹ Therefore, ACC believes it is inappropriate for EPA to set limits under this boiler rule that cannot be met consistently by a top performing unit under all operating conditions. One way to consider a unit's variability in emissions is to set a longer averaging time for compliance with an emission limit.

[Footnote 20 EPA relied on a 2004 decision, *Mossville Environmental Action Now v. EPA*, 370 F.3d 1232 (D.C. Cir. 2004), holding EPA may consider emission variability in estimating performance achieved by best-performing sources and may set the floor at level that best-performing source can expect to meet “every day and under all operating conditions.”]

[Footnote 21: See for example 73 Fed. Reg. 64071: “To account for the bias in the analytic method, we corrected all TCl emissions data that were below 20 ppmv to 20 ppmv. We accounted for within-test condition emissions variability for the corrected data by imputing a standard deviation that is based on a regression analysis of run-to-run standard deviation versus emission concentration for all data above 20 ppmv. This approach of using a regression analysis to impute a standard deviation is similar to the approach we used to account for total variability (i.e., test-to-test and within-test variability) of particulate matter emissions for sources that use fabric filters.”]

Response: The emission limits established do consider not only operational variability but also fuel variability. Compliance with these emission limits are based on performance tests with continuous compliance based on maintaining operating limits. In most cases, the averaging time for the operating limits is a 30-day rolling average.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 58

Comment: ACC also requests that EPA add a 30-day averaging period to the operating load requirement. Table 4 (item 8) and Table 8 (item 11) require operators to maintain the operating load of each unit such that it does not exceed 110 percent of the average operating load recorded during the most recent performance test. For the same reasons provided above for the other operating parameters, EPA should allow a 30-day averaging period for operating load so short term high load periods that are more than 10 percent above the tested load do not result in deviations. Facilities make every attempt to schedule stack tests during periods of high utilization, but sometimes need to operate at more than 100 percent of the load achieved during the stack test for short periods of time in order to meet operational demands. The way the requirement is currently written implies that the 110 percent load limitation is instantaneous. ACC recommends that both Table 4 (item 8) and Table 8 (item 11) be modified to include a stipulation that the operating limit is on a 30-day rolling average basis. For comparison, 40 CFR 63 Subpart JJJJJ Table 7 (item 9) does include the 30-day rolling average basis for the operating load limit.

Response: We agree that an averaging period should be added to the operating load requirement because the requirement, as currently written, implies that the 110 percent load limitation is instantaneous. For the same reasons provided for the other operating parameters, Table 8, item 11(b) has been revised to allow a 30-day averaging period for operating loads so short term high load periods, to meet operational demands, that are more than 10 percent above the tested load do not result in deviations. This change is also consistent with Table 7 of the Boiler Area Source Rule (subpart JJJJJ) rule in which the load monitoring requirement does have a 30-day averaging period specified.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 107

Comment: We request that EPA add a 30-day averaging period to the operating load requirement. Table 4 requires operators to maintain the operating load of each unit such that it does not exceed 110 percent of the average operating load recorded during the most recent performance test. For the same reasons provided above for the other operating parameters, EPA should allow a 30-day averaging period for operating load so short term high load periods that are more than 10 percent above the tested load do not result in deviations. Facilities make every attempt to schedule stack tests during periods of high utilization, but sometimes need to operate at more than 100 percent of the load achieved during the stack test for short periods of time in order to meet operational demands. The way the requirement is currently written implies that the 110 percent load limitation is instantaneous. We note that in Table 7 of the Boiler GACT rule, the load monitoring requirement does have a 30-day averaging period specified.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 58.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 104

Comment: We also request that EPA add a 30-day averaging period to the operating load requirement. Table 4 (item 8) and Table 8 (item 11) require operators to maintain the operating load of each unit such that it does not exceed 110 percent of the average operating load recorded during the most recent performance test. For the same reasons provided above for the other operating parameters, EPA should allow a 30-day averaging period for operating load so short term high load periods that are more than 10 percent above the tested load do not result in deviations. Facilities make every attempt to schedule stack tests during periods of high utilization, but sometimes need to operate at more than 100 percent of the load achieved during the stack test for short periods of time in order to meet operational demands. The way the requirement is currently written implies that the 110 percent load limitation is instantaneous. CIBO recommends that both Table 4 (item 8) and Table 8 (item 11) be modified to include a stipulation that the operating limit is on a 30-day rolling average basis. For comparison, 40 CFR 63 Subpart JJJJJ Table 7 (item 9) does include the 30-day rolling average basis for the operating load limit.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 58.

Commenter Name: Douglas A. McWilliams

Commenter Affiliation: American Municipal Power

Document Control Number: EPA-HQ-OAR-2002-0058-3685-A2

Comment Excerpt Number: 37

Comment: As the rule is currently written, the averaging period for load and oxygen operating limits is unclear. Sources with highly variable loads, such as utility boilers, may occasionally experience loads in excess of ten percent of the stack tested rate for short periods of time, followed by periods of low load. These load swings will also affect oxygen adjustment, and maintaining a proper oxygen mix during period of load fluctuation is critical to maintaining safe operation of the boiler. The standard as written does not provide sources with clear means of demonstrating compliance in these circumstances, and as a result fails to account for the same variability that affects other operating parameters and that EPA acknowledged made a 30-day averaging period appropriate. EPA should establish a 30-day rolling average for all operating parameters in the final rule.

Response: For a response to the request for a 30-day averaging period to be added to the operating load limits, please see comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 58. For a response to the request for a 30-day averaging period to be added to the oxygen trim monitoring limits, please see comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 108.

Commenter Name: Chris M. Hobson

Commenter Affiliation: Southern Company

Document Control Number: EPA-HQ-OAR-2002-0058-3520-A1

Comment Excerpt Number: 13

Comment: Opacity monitoring should be based on a 30-day rolling averaging, consistent with other parameter monitoring, instead of being based on a 24-hour block.

Response: While the commenter asserts the averaging period for opacity operating limit should be changed for consistency, it provides no information to support this assertion. While the other operating limits are set based on levels measured during the compliance tests, the opacity operating is not based on comments received during the 2004 Boiler MACT rulemaking.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 109

Comment: EPA should specify how a 30-day rolling average for the operating parameter limits is calculated, indicating that it includes the previous 720 hours of valid operating data. EPA should make clear that valid data excludes hours during startup and shutdown as well as unit down time. This clarification will be helpful in implementation, as some permitting authorities have interpreted how compliance is demonstrated with rolling averages in odd and sometimes unintended ways. For example, when a unit is down for an outage, state regulators have sometimes sought to continue the 30-day calculation through the outage. We believe that such interpretation would be outside EPA's intention in setting the operating parameter limits on a long term basis in order to accommodate variability. Specification of the minimum number of readings helps to ensure that the 30-day average concept will not be undermined.

Response: We agree with the commenter that how the 30-day average is determined needs to be clarified. The definitions of 10-day rolling average and 30-day rolling average have both been

revised to indicate that it is based on hours, and not days, and what hour periods are to be excluded.

Commenter Name: Mary Sullivan Douglas

Commenter Affiliation: National Association of Clean Air Agencies (NACAA)

Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1

Comment Excerpt Number: 23

Comment: EPA has proposed that owners and operators use parametric monitoring (i.e., pH, pressure drop, scrubant flow rate, etc.) based on stack testing to demonstrate continuous compliance with applicable emission limits. The averaging period used for the parametric monitoring in the original Boiler MACT finalized in March 2011 was a 12-hour average. In the currently proposed amendments, EPA is requiring proposing that owners and operators instead use a 30-day rolling average. This creates an averaging period for parametric monitoring that is grossly inconsistent with the emission standard set through initial performance test (stack testing). The averaging period for a stack test for an emission standard, such as particulate, is typically determined from the average of three stack test runs, which would be only one- to twohour long runs. Where the emission standard is based on the average of three, one-hour stack tests, parametric monitoring with a 30-day rolling average (or even a 12-hour average) will not ensure compliance as the affected unit could be operated outside of the range (and presumably above its three-hour emission limit) for half the month. We do not object to the use of long-term averages *per se*, as such averages can be a solution to the variability issue. However, there is then no technical justification for the very large variability factors adopted by EPA (based on one-hour test runs) in a system that permits 30-day averages to be used for compliance.

Response: We disagree that there is no technical justification for the variability factors adopted. The only variability factors used are fuel variability factors which are based on the actual average variability of the HAP constituent in the fuel combusted by the best performing units. The variability included in the MACT floor analysis is the statistical variability based on the actual variability of the emission test results from the best performing units. While the commenter asserts that parametric monitoring with a 30-day rolling average will not ensure compliance as the affected unit could be operated outside of the range (and presumably above its three-hour emission limit) for half the month, it provides no information or analysis to support this assertions.

Commenter Name: Bart Sponsellar

Commenter Affiliation: Wisconsin Department of Natural Resources

Document Control Number: EPA-HQ-OAR-2002-0058-3527-A2

Comment Excerpt Number: 17

Comment: The EPA is requesting comment on allowing 30-day averaging of parametric operating parameters monitored for compliance. The Department supports averaging over the 30-day rolling period. Based on past experience with sources, this approach is appropriate to address variability in operations while ensuring continuous control effort. However, the Department is aware that existing equipment for facilities is not set up to perform and record this averaging function. One example is the excess air (oxygen) monitoring currently in place for many sources.

These systems are currently set up to produce a value and trim the system on a continuous basis. Other examples are ESP voltage or fabric filter pressure readings. The Department requests for EPA to clarify that such values, which are not averaged, can be used to demonstrate compliance. Basically, this approach is more restrictive than using values averaged over 30 days. Clarifying how to follow this more stringent approach will allow sources to use current monitoring and data systems without additional modifications.

Response: The EPA thanks the commenter for their support of the 30-day rolling average period. We agree with the commenter that it is an unnecessary requirement to require a source using an oxygen trim system to monitor and report oxygen levels on a 30-day rolling average because 63.7525(a)(2) in the final rule requires a source that operates an oxygen trim system to set the oxygen level no lower than the lowest hourly average oxygen level measured during the CO performance test. Tables 4 and 8 have been revised to reflect this change.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 113

Comment: Achievable flow meter sensitivities should be specified.

Proposed §63.7525(e)(2) specifies that a required flow meter have "a measurement sensitivity of no more than the expected flow rate." However, if the expected flow rate is less than the design flow rate or it does not meet this criteria over the entire range of potential flows an additional, separate flow meter may be needed to meet this sensitivity requirement at all flow rates. This additional instrumentation does not appear to have been considered in evaluating the proposal burden or cost. Nor is it clear what constitutes "expected." Is that what is expected tomorrow, next week, next year, at any time? We see no reason why standard instrumentation is unacceptable and why the existing instruments cannot be used. We, therefore, recommend that this provision be revised to require that the flow meter have a measurement sensitivity of no greater than 2% at the design flow rate.

Response: We agree with the commenter and 63.7525(e)(2) has been revised to change "expected" to "design."

Commenter Name: M.L. Steele

Commenter Affiliation: CraftMaster Manufacturing, Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3814-A1

Comment Excerpt Number: 20

Comment: The averaging period for the maximum allowable operating steam load in Table 8 is not specified. CraftMaster requests that the averaging period be specified as the 24-hour average to be consistent with other programs.

Response: The averaging period for the load operating limit in Table 8 has been revised to a 30-day rolling average to be consistent with the other operating limits.

11H. Reduced Testing Allowance

Commenter Name: David A. Buff, Golder Associates Inc.
Commenter Affiliation: Florida Sugar Industry (FSI)
Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1
Comment Excerpt Number: 57

Comment: The FSI fully supports EPA's decision to allow decreased stack testing if the tests consistently demonstrate compliance with the applicable emission limit. EPA adopted the same approach in the New Source Performance Standards for Municipal Waste Combustors (40 CFR 60, Subpart Eb) and it has worked successfully for many years. This approach will save money on testing while providing reasonable assurance of ongoing compliance with the emission limits in the Boiler MACT rule.

Response: The EPA thanks the commenter for their support.

Commenter Name: John S Williams
Commenter Affiliation: Maine Pulp & Paper Association (MPPA)
Document Control Number: EPA-HQ-OAR-2002-0058-3466-A1
Comment Excerpt Number: 11

Comment: The proposed rule will allow units that demonstrate compliance for a particular pollutant at a level at or below 75 percent of the emission limit for 2 consecutive years to forego stack testing for up to 37 months. Since most pollutant testing will be completed during worst case scenarios, this allowance will likely provide no relief of the performance test requirement's costly burden. Also, because of the worst cast fuel mix and operating limit requirements, many multiples of stack testing scenarios will be required

Response: We disagree that because most pollutant testing will be completed during worst case scenarios, the allowance will provide no relief of the performance test requirement's costly burden. The emissions limits are based on the average of the emissions from the best performing units which were conducted under their worst case scenarios. A review of the emissions from these best performing units show that a unit can achieve 75 percent of the limits to which the criterion applies with available controls.

Commenter Name: Lee Zeugin and Lauren Freeman
Commenter Affiliation: Utility Air Regulatory Group (UARG)
Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1
Comment Excerpt Number: 39

Comment: Under the 2011 final rule, periodic performance testing for IB units not relying on CEMS or fuel input sampling must be completed within 13 months of the previous test, except for (1) units subject to certain emission limits specified in Tables 1 and 2, and (2) units with test data showing emissions "at or below 75 percent of the emission limit" for at least 2 consecutive years. Such units may test every third year as long as no changes in source or control device operation have occurred that could increase emissions. 40 C.F.R. § 63.7515(a) - (c). The reduced testing proposal applies to all sources and tests except sources using emission averaging. In

comments on the 2010 proposed rule, UARG supported inclusion of a reduced testing provision, but questioned the reasonableness of the 75 percent criterion given the extremely low levels of EPA's proposed limits. UARG noted the Agency's failure to provide a rationale for the criterion, or data suggesting that any source could achieve 75 percent of the proposed emission limits, some of which are established at or near the detection limit. EPA-HQ-OAR-2002-0058-2880.1 at 24-25. Because EPA finalized the rule without addressing or responding to UARG's comments, UARG included the issue in its reconsideration petition. EPA-HQ-OAR-2002-0058-3324 at 3.

On reconsideration, EPA proposes to retain the current rule but solicits comment on it. EPA asserts that it addressed any concerns with achievability by exempting those limits in Tables 1 and 2 that were replaced in the standard setting process by three times the "representative detection limit" ("RDL") because that was deemed the lowest level that can be measured accurately. 76 Fed. Reg. at 80,617/1.

Although UARG appreciates EPA's recognition of the significance of measurement capabilities and detection levels in establishing a reduced testing criterion, EPA's approach in the final rule fails to address the capabilities of available controls. As a result, although UARG supports the existing exclusions, to make the 75 percent criterion meaningful, EPA still would have to show that a unit could achieve 75 percent of the limits to which the criterion applies with available controls. EPA has provided no data or analysis. The requirement that source and control device operation remain consistent with prior successful testing should be sufficient to ensure representativeness of the prior tests without requiring sources to demonstrate a significant margin of compliance to qualify for reduced testing. If such a margin of compliance is not possible to consistently achieve, the reduced testing provision has no meaning.

Response: We disagree that EPA's approach in the final rule fails to address the capabilities of available controls. The emissions limits are based on the average of the best performing units and including operational variability. A review of the emissions from these best performing units show that a unit can achieve 75 percent of the limits to which the criterion applies with available controls.

Commenter Name: Vickie Woods

Commenter Affiliation: Division of Air Quality, North Carolina Department of Environment and Natural Resources (NCDENR)

Document Control Number: EPA-HQ-OAR-2002-0058-3663-A2

Comment Excerpt Number: 26

Comment: NC DAQ further supports the use of a reduced testing frequency for those sources that are able to demonstrate consistent emission rates well-below the emission limits. However, DAQ believes that this test frequency should be viewed in context of operations between emissions tests.

Response: The EPA thanks the commenter for their support of reduced testing frequency. While the commenter believes that this test frequency should be viewed in context of operations between emissions tests, it provides no information to support this assertion.

Commenter Name: Mary Sullivan Douglas
Commenter Affiliation: National Association of Clean Air Agencies (NACAA)
Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1
Comment Excerpt Number: 51

Comment: EPA has proposed reduced testing frequency for sources whose emission tests are at or below 75 percent of the emission limit. This suggestion is inconsistent with EPA's determination that emissions from well-controlled sources routinely vary by more than an order of magnitude.

Response: We disagree that the proposed reduced testing frequency is inconsistent with our determination that there is variability in emissions from well-controlled sources. The reduced stack testing frequency does not, in any way, reduce the requirement for the source to continuously monitor the appropriate operating limit to demonstrate continuous compliance with the emission limit. The source is required to maintain that operating parameter below or above the operating limit established during the performance test. Maintaining the appropriate operating limit ensures that emissions do not vary by more than an order of magnitude.

Commenter Name: Matthew Todd
Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)
Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2
Comment Excerpt Number: 100

Comment: We support the proposed reduced stack testing frequency if testing demonstrates operation well below the limit (or at the limit if the limit was based on the representative detection limit), but request some additional relief for BPH in the non-continental liquids subcategory. We also recommend this sensible approach to reducing burdens be extended to fuels analysis.

Response: The EPA thanks the commenter for their support of reduced stack testing allowance. We agree with the commenter that a similar allowance should be extended to fuel analysis and, in the final rule, 63.7515(f) has been revised to include similar language as for stack testing frequency.

Commenter Name: Samuel H. Bruntz
Commenter Affiliation: Alcoa Power Generating, Inc.
Document Control Number: EPA-HQ-OAR-2002-0058-3755-A1
Comment Excerpt Number: 4

Comment: Proposed regulation 63.7515 (a) through (d) is unnecessary, if the unit continuously monitors compliance with the PM limit through use of a CEMS. Alcoa-Warrick thus suggests the following revision to 63.7515 (a):

"63.7515(a) Unless you are demonstrating continuous compliance through operation of a PM-CEMS, HCl-CEMS, SO₂ CEMS as a surrogate for HCl, mercury CEMS or mercury Appendix K

absorption tubes, you must conduct all applicable performance tests according to § 63.7 520 on an annual basis, except as specified in paragraphs (b) through (d)(e) of this section."

Response: We disagree with the commenter that units using CEMS should be exempt from performance testing. The emission limits are based on the results of performance testing. Thus, compliance is demonstrated by performance testing. The CPMS required in the rule are operating limits that must be maintained to demonstrate continuous compliance.

11I. Coal Sampling Technique

Commenter Name: Lee Zeugin and Lauren Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1

Comment Excerpt Number: 41

Comment: EPA adds an option for use of an automated sampling system. Proposed § 63.7521(c). EPA replaces the requirements for use of a square shovel, for sampling at a depth of "exactly" 18 inches, and for breaking of pieces larger than 3 inches, with more moderate requirements. Proposed § 63.7521(c)(2) and (d). UARG appreciates and supports these changes, which will reduce burden without sacrificing representativeness.

Response: The EPA thanks the commenter for their support.

Commenter Name: Mary Sullivan Douglas

Commenter Affiliation: National Association of Clean Air Agencies (NACAA)

Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1

Comment Excerpt Number: 52

Comment: NACAA agrees that sources may employ automated fuel-sampling equipment, but notes that the 90th percentile compliance obligation is inconsistent with EPA's determination that MACT floors must be set at a 99th percentile level.

Response: The EPA thanks the commenter for their support of automated fuel-sampling equipment. We disagree that the 90th percentile obligation is inconsistent with the 99th percentile used for development of the MACT floors. In one case (MACT floors), an emission limitation is being established that must be achieved at all times factoring the inherent variability of testing, control performance, operational variations, and fuel variability, so basing the MACT floors on the 99% UPL was appropriate. In the other (compliance by fuel analysis), we conducted an analysis to determine an appropriate statistical approach that would minimize the frequency of conducting fuel analysis to demonstrate continuous compliance. Given the significant variability in the HAP content of coal, there were concerns about requiring only an initial sampling and testing of the fuel as a means of ensuring ongoing compliance. Conceptually, accounting for variability would eliminate the need for frequent sampling; but only if we adopted a statistical analysis that accounts for the variability that can possibly occur in the applicable fuel type. Various percentile confidence levels were analyzed. Based on this statistical analysis, the appropriate percentile confidence level for ensuring continuous compliance was determined to be 90. Coal sets with all monthly values below the benchmark

had their 90th percentile confidence limit also below the benchmark. For coals sets with any monthly values at or above the benchmark, the 90th percentile confidence level was above the benchmark.

Commenter Name: Pat Dennis

Commenter Affiliation: Archer Daniels Midland Company

Document Control Number: EPA-HQ-OAR-2002-0058-3670-A2

Comment Excerpt Number: 16

Comment: EPA should not attempt to prescribe coal sampling methodologies in this rule but rather should simply reference ASTM standards and allow for reasonable equivalency with regard to smaller sources.

Response: The EPA has provided multiple ASTM coal sampling methods in the rule; specifically ASTM D5192 – 09, D7430, D6883, and D2234.

11J. Fuel Analysis Methods

Commenter Name: Douglas Price

Commenter Affiliation: Tesoro Companies, Inc

Document Control Number: EPA-HQ-OAR-2002-0058-3630-A2

Comment Excerpt Number: 2

Comment: For liquid fuel fired sources, the re-proposed 40 C.F.R. Subpart DDDDD rule allows for emission limit compliance to be demonstrated by analyzing the fuel burned in affected boilers and process heaters for mercury (Hg) and chlorine content. Table 6 lists the specific methods to be used for analyzing the fuel and includes one method, EPA SW-846-7470A, for determining the Hg content. Also, the rule language directly above Table 6 states the following:

“As stated in § 63.7521, you must comply with the following requirements for fuel analysis testing for existing, new or reconstructed affected sources. However, equivalent methods (as defined in § 63.7575) may be used in lieu of the prescribed methods at the discretion of the source owner or operator: .. ”

While this rule language could be read that once a source owner or operator determines the alternative method meets the definition of "equivalent," it can be used without further approval, 63.7521 (b)(2) requires a specific process to be followed in order for another test method to be considered "equivalent" to the method listed in Table 6. The process includes requesting the use of the alternative method in the required fuel monitoring plan and then EPA must approve the method, as described in 63.7521 (b)(2)(v). The Table 6 listed method must be used until the alternative method is approved by the EPA, which could be an extended period of time.

The Kapolei Refinery has historically analyzed the fuel oil for Hg content using the laboratory test method SW-846-1631E. Tesoro considers this test method to be the best approach and it has been used for over 10 years, not only for fuel oil analysis but also for crude oil analysis. In addition, in a previous version of 40 C.F.R. Subpart DDDDD, the EPA approved the use of test method SW-846-1631/1631E as being "equivalent."² Lastly, this method was approved by the

EPA for analyzing distillation feed samples as part of the EPA's 2011 Petroleum Refinery information collection request (ICR).³

While the current re-proposed 40 C.F.R. Subpart DDDDD rule provides a process to determine this method SW-846-1631E because it is a method that has already been determined as equivalent by the EPA. If this method is not added to the final 40 C.F.R. Subpart DDDDD, Tesoro would be forced to switch to another method for an unknown period of time until the alternate method is approved by EPA, which we consider to be unnecessary.

Recommendation: For the reasons described above, Tesoro requests that test method SW-846-1631E be added to Table 6 of the final rule.

[Footnote 2: See FR 71 70653]

[Footnote 3: See "Petroleum Refinery Emissions Information Collection: Part IV: Summary of Test Procedures, Methods, and Reporting Requirements for Distillation Feed Composition Analysis" (OMB Control No. 2060-0657)]

Response: The EPA agrees with the commenter and finds SW-846-1631E to be equivalent to SW-846-7470A, as listed in Table 2 of this document:
https://refineryicr.rti.org/Portals/0/Instructions_for_Component_3_Distillation_Feed_Sampling.pdf; and has modified table 6 of the rule as requested.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 111

Comment: Compliance procedures do not appear to be included in the proposal for demonstrating compliance with the Total Selected Metals limit for Gas 2 and they should be added. Procedures for showing compliance with TSM limits where solid fuels are combusted are included (e.g., §§63.7530(c)(5) and 63.7530(b)(1)) in the proposal, but Gas 2 procedures appear to be lacking and should be added. These procedures should clearly state that analyses are only needed for metals that are expected to be present in the gas. Typically, only process related metals will be present in Gas 2 and the owner/operator will know what those metals are. There is no reason to require testing for other metals in that case and we request that the gas 2 procedures be clear on this point.

Response: We disagree with the commenter. The TSM compliance procedures in 63.7530(b) and (c) are in regards to fuel analysis not stack testing. We are not aware of proven test methods to quantify the content of metals in gaseous fuel. The procedures listed in Table 5 of the rule for TSM are applicable to Gas 2 units.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 124

Comment: The requirement to measure the water content of the stack gas in Table 5 Item 4.c. is unnecessary and should be deleted. Item 4 of Table 5 deals with determining the CO content of a boiler or process heater stack. EPA Method 10 is specified as the method for determining the CO content in Item 4.d. Method 10 measures the CO on a dry basis and thus there is no need to determine the moisture content in the stack in order to correct the measured CO concentration to a dry basis.

Method 10 for CO refers back to Method 7E – which specifies the following water removal step as follows.

6.2.4 Conditioning Equipment. For dry basis measurements, a condenser, dryer, or other suitable device is required to remove moisture continuously from the sample gas. Any equipment needed to heat the probe or sample line to avoid condensation prior to the sample conditioning component is also required.

Response: The EPA recognizes that measurements may involve conditioning of stack gas to remove moisture prior to CO measurement; however we are leaving this requirement in the rule to accommodate dilution sampling systems that do not make use of this option. Measurement and reporting in the rule will remain on a dry basis.

Commenter Name: Kerry Kelly

Commenter Affiliation: Waste Management (WM)

Document Control Number: EPA-HQ-OAR-2002-0058-3681-A2

Comment Excerpt Number: 22

Comment: According to Table 6 of the Proposed Boiler MACT Reconsideration Rule, you must conduct fuel analysis for mercury using one of the four prescribed test methods, or equivalent method. However, §63.7521(g)(2)(vi) appears to prevent gaseous fuel suppliers from requesting approval to use alternative test methods. The boiler owner/operator on the other hand may request approval to use an alternative test method. No explanation or rationale is provided for this inflexible requirement. Furthermore, it is likely to affect most of the analysis conducted under this section of the rule. We believe it is highly likely that purchasers of gaseous fuels will require their fuel suppliers to develop the analyses and documentation necessary to qualify them as an “other Gas 1 fuel.” We strongly recommend EPA remove this language so that all analyses conducted for use of other Gas 1 fuels may utilize methods listed in §63.7521(f)-(i) or equivalent methods.

Response: We disagree. The requirement in 63.7521(g)(2)(vi) for gaseous fuel suppliers is identical to the requirement in 63.7521(b)(2)(vi) for non-gaseous fuel suppliers. These section require that the fuel suppliers must use the methods required by Table 6 of the rule. Table 6 list certain specific methods but allows the use of any equivalent methods. The term "equivalent" is defined in 63.7575.

Commenter Name: Kerry Kelly
Commenter Affiliation: Waste Management (WM)
Document Control Number: EPA-HQ-OAR-2002-0058-3681-A2
Comment Excerpt Number: 23

Comment: WM requests that EPA incorporate additional test methods in the rule that can be used under §63.7521. §63.7521 states that a gaseous fuel other than natural gas or refinery gas can be qualified as a “Gas 1” fuel by conducting fuel testing according to methods laid out in Table 6. Specifically, Table 6 requires that the mercury concentration in the fuel must be measured using one of the following test methods: “ASTM D5954, ASTM D6350, ISO 6978–1:2003(E) or ISO 6978–2:2003(E) (or an equivalent test method)”. The Agency states that the methods in Table 6 “shall be used” unless an alternative analytical method is specifically approved. The required test methods listed in EPA’s referenced table are typically used for natural gas analyses, and have not been proven to be appropriate for analyzing LFG for mercury. Further, because gaseous fuel suppliers are not allowed to use alternative methods, WM would be forced to use an unproven method to demonstrate our LFG compliance with the certification requirements. All four of the listed test methods were developed to determine mercury levels in natural gas, not LFG, but the composition and physical properties of LFG and natural gas differ.

For example, natural gas is primarily methane with lower concentrations of related alkanes and carbon oxides, and trace quantities of other hydrocarbons. LFG typically contains 45% to 60% methane and 40% to 60% carbon dioxide. LFG also includes small amounts of nitrogen, oxygen, ammonia, sulfides, hydrogen, and carbon monoxide. The complexity of component fuels typically encountered in sampled LFG often renders the methods typically used for natural gas characterizations inappropriate. Either interferences or target analyte levels may disqualify natural gas methods when attempting to acquire representative Hg data in LFG. The performance of these methods in an LFG matrix has yet to be demonstrated. As a result, it is inappropriate for the Agency to categorically require that, in the absence of a pre-approval process, only the four methods listed in Table 6 may be used for mercury testing in LFG.

Response: We disagree that only the four methods listed in Table 6 may be used for mercury testing in LFG. Table 6 allows for methods that are "equivalent" and sources may request to use an alternative analytical method than those in Table 6 as stated in 63.7521(c)(2)(v).

Commenter Name: Douglas A. McWilliams
Commenter Affiliation: American Municipal Power
Document Control Number: EPA-HQ-OAR-2002-0058-3685-A2
Comment Excerpt Number: 49

Comment: EPA has included numerous compliance demonstration alternatives in the Proposed Rule. AMP appreciates EPA's efforts to provide flexibility to the regulated community and supports EPA's inclusion of the following optional compliance alternatives:

- Use of fuel testing to demonstrate compliance with HCl, Hg, and TSM limits

Response: The EPA thanks the commenter for their support.

Commenter Name: Russell A. Wozniak
Commenter Affiliation: The Dow Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3449-A1
Comment Excerpt Number: 12

Comment: EPA Reference Method 30B (Determination of Total Vapor Phase Mercury Emissions from Coal-Fired Combustion Sources Using Carbon Sorbent Traps) in 40 CFR 60 Appendix A should be added to the list of approved methods in Table 6 Section 3 or should be considered as an equivalent to the listed methods.

Section 3. of Table 6 lists acceptable analytical methods for measuring the mercury concentration in the off-gas fuel to show that the concentration is less than 40 micrograms per cubic meter. EPA should consider adding EPA Method 30B to the list of approved methods or noting the method as "equivalent" to the listed methods. EPA Reference Method 30B was developed to determine the mercury content in waste gas streams associated with coal combustion. However, our understanding is that external stack testing companies have successfully used this method to measure the mercury concentration in off-gas streams that are used as fuel in boilers and process heaters. External lab partners assure us that from past experience that Method 30B is superior and Dow Chemical Comments Page 6 Docket EPA-HQ-OAR-2002-0058

more accurate than any of the older methods that are currently listed in the rule. The method is also easier and safer to implement and conduct in the field since the other methods listed by EPA require an in-situ analysis of the fuel stream.

Method 30B is designed to measure the mass concentration of total vapor phase Hg, including elemental mercury and oxidized forms of Hg in micrograms per cubic meter. The analytical range and sensitivity is typically in the range of 0.1 micrograms per dry standard cubic meter to 50 micrograms per dry standard cubic meter which should be adequate to demonstrate that the mercury content is less than 40 micrograms per cubic meter.

Response: We have not seen any data to support the contention that Method 30B as written would be appropriate for sampling and analysis of off-gas fuel. In particular, we would be concerned that (1) the sampling approach of Method 30B is not immediately applicable to the pressures in gas lines and (2) we have not yet seen data demonstrating that there is a sorbent appropriate for this type of sample matrix. Given these concerns, we believe it best, in lieu of including Method 30B in Table 6 of the rule at this time, that the alternative test method provisions of 63.7(f) be used during rule implementation to determine if Method 30B could be considered equivalent. The requester would need to provide us with supporting procedures and data as described in 63.7(f) and the [Federal Register Notice](#) at 72 FR 1/7/2007, page 4257.

Commenter Name: Matthew Todd
Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)
Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2
Comment Excerpt Number: 179

Comment: Method SW-846-1631E should be added to Table 6 as an approved mercury determination method. This method was approved by the EPA for analyzing distillation feed samples as part of the EPA's 2011 Petroleum Refinery information collection request (ICR) and has been used for years by some member companies for determining mercury in fuel oils.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3630-A2, excerpt 2.

Commenter Name: Kerry Kelly

Commenter Affiliation: Waste Management (WM)

Document Control Number: EPA-HQ-OAR-2002-0058-3681-A2

Comment Excerpt Number: 24

Comment: Numerous studies have been conducted to measure mercury in LFG, including several conducted for EPA. The table below [See pg 13 of submittal for table] lists the test methods used in these studies, the methods specified in Table 6, and, for each method, whether it was included in the Agency's proposed Boiler MACT Reconsideration Rule. This table shows that none of the methods used in the published mercury LFG studies, including those sponsored by EPA, were included in Table 6 of the proposed rule. Conversely, none of the methods in Table 6 were relied on in any of the mercury LFG studies.

This examination of fuel testing methods clearly indicates that the Agency should expand Table 6 to include additional options for measuring mercury in gas fuels. At a minimum, methods that have been tested and proven reliable in mercury LFG studies, particularly EPA Method 30B and EPA Method 1631, both of which are already approved EPA testing methods and have been evaluated for accuracy and precision in LFG studies, should be included as acceptable methods in the mercury fuel specification section in Table 6. Additionally, it is recommended that the Agency consider and evaluate the accuracy, precision, selectivity and sensitivity of the current methods included in Table 6, taking into account their applicability to gas fuels other than natural gas or refinery gas.

Response: For a response to the request to include Method 30B testing, see EPA-HQ-OAR-2002-0058-3449-A1, excerpt 12 which states that in lieu of including Method 30B in Table 6 of the rule at this time, that the alternative test method provisions of 63.7(f) be used during rule implementation to determine if Method 30B could be considered equivalent. The rule contains a definition of "equivalent" method. Equivalent methods are voluntary consensus standards (VCS) or EPA methods which are applicable to the fuel type or target analyte being measured. Although we disagree with adding the methods listed in the comment letter to Table 6 in the final rule, we would consider the following methods in the comment letter as equivalent: EPA Method 1631, Modified SW-846 Method 7473, ASTM D5954, ASTM D6350, ISO 6978-1:2003, ISO-6978-2:2003, and CARB Method 436. Equivalent methods may be used in lieu of the prescribed methods in Table 6 to subpart DDDDD at the discretion of the source owner or operator. Therefore, publishing a list of or adding to the list of approved methods is not necessary. Similarly, State or EPA approval of equivalent methods is not necessary.

Commenter Name: Kerry Kelly

Commenter Affiliation: Waste Management (WM)

Document Control Number: EPA-HQ-OAR-2002-0058-3681-A2

Comment Excerpt Number: 26

Comment: We had difficulty identifying laboratories that have capability (equipment and experience) to perform the test methods listed in Table 6 for determining mercury in LFG, specifically ASTM D5954. After contacting several large accredited laboratories, including research laboratories and laboratories that service the oil and gas industry, we located only one laboratory that has the required equipment to run ASTM D5954 for mercury analysis in LFG. However, this laboratory has only performed analysis to determine mercury in LFG in a research capacity rather than for clients concerned with ongoing compliance obligations. Unfortunately, after contracting with the laboratory and sending them our samples, the equipment required to perform the sample analysis for ASTM D5954 broke down and will not be repaired for at least two weeks as it requires a replacement part that must be shipped from Japan. This circumstance prevents the laboratory from conducting analysis on collected LFG samples it received February 13. A further complication is that the laboratory's quality control sample hold time is 30 days, which may render our samples unusable. This same laboratory also does not have capability (equipment) to perform ASTM D6350 on the collected samples and cannot identify another laboratory to complete timely analysis using ASTM D6350. This lack of laboratory capability and capacity across the nation amplifies the limitations with Test Methods prescribed in Table 6 of the proposed Boiler MACT Reconsideration Rule for LFG and other gaseous fuels. WM would like to share lessons learned from this field study with EPA, specifically whether the test methods listed in Table 6 for determining mercury (in natural gas) are applicable to other gaseous fuels (e.g., LFG). Therefore, we respectfully request that the Agency accept information gathered as part of this field study as supplemental comments on the proposed Boiler MACT Reconsideration Rule if/once we receive the final ASTM D5954 results from the laboratory. We believe our comments demonstrate the appropriateness of incorporating other test methods in the proposed Boiler MACT Reconsideration Rule.

Response: For a response to using other methods not listed in Table 6, see comment EPA-HQ-OAR-2002-0058-3681-A2, excerpt 24.

Commenter Name: Jim Cetrullo

Commenter Affiliation: TestAmerica

Document Control Number: EPA-HQ-OAR-2002-0058-3744-A1

Comment Excerpt Number: 1

Comment: TestAmerica was recently requested by a client to provide analytical services for determination of mercury in landfill gas using the methods specified in Table 6 of the Proposed Reconsideration of the Final Rule for National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

[EPA-HQ-OAR-2002-0058]. TestAmerica is considered a full service provider of analytical services and none of the methods listed in Table 6 were available to clients at any of our laboratory facilities.

TestAmerica requests that EPA incorporate additional test methods in the rule that can be used under §63.7521. §63.7521 states that a gaseous fuel other than natural gas or refinery gas can be

qualified as a "Gas 1" fuel by conducting fuel testing according to methods laid out in Table 6. Specifically, Table 6 requires that the mercury concentration in the fuel must be measured using one of the following test methods: "ASTM D5954, ASTM D6350, ISO 6978-1:2003(E) or ISO 6978-2:2003(E) (or an equivalent test method)". The Agency states that the methods in Table 6 "shall be used" unless an alternative analytical method is specifically approved.

TestAmerica searched for commercially available laboratories that could perform one or more of the specified methods. The search found only a single laboratory that was able to perform any of the methods; and, the one Table 6 specified method that the laboratory performed was ASTM D5954. Technical discussions with that laboratory revealed that the Table 6 specified method(s) were developed for analysis of natural gas and had not been thoroughly tested and proven to be adequate for landfill gas analysis.

Numerous studies have been conducted to measure mercury in LFG, including several conducted for EPA. None of the studies reviewed by us have used the Table 6 specified methods as the approach for determination of mercury in LFG. However, several have used EPA Method 30B and EPA Method 1631 as the methods of choice for determination of mercury in landfill gas. Since data from EPA 30B and EPA 1631 for mercury analysis in landfill gas are readily available in the public domain, it is recommended that these methods be specifically added to Table 6. It is also recommended that language be added that gives more flexibility in the choice of methods so that there will be some certainty that the regulated community will have an adequate number of qualified laboratories available to them to provide these testing procedures.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3681-A2, excerpt 24.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 137

Comment: ACC recommends EPA add Method 30B as an approved method for demonstrating that a gas fuel meets the specification for "Other Gas 1 Fuel" in Table 6 of the rule, or note that the method is "equivalent" to the listed methods. EPA Reference Method 30B was developed to determine the mercury content in exhaust gas streams associated with coal combustion. However, our members have indicated that external stack testing companies have successfully used this method to measure the mercury concentration in off-gas streams that are used as fuel in boilers and process heaters. External lab partners assure our members that Method 30B is superior and more accurate than any of the older methods that are currently listed in the rule. The method is also easier and safer to implement and conduct in the field since the other methods listed by EPA require an in-situ analysis of the fuel stream. Method 30B is designed to measure the mass concentration of total vapor phase mercury, including elemental mercury and oxidized forms of mercury in micrograms per cubic meter. The analytical range and sensitivity is typically in the range of 0.1 to 50 micrograms per cubic meter, which should be adequate to demonstrate that the mercury content is less than 40 micrograms per cubic meter.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3449-A1, excerpt 12.

Commenter Name: Shannon S. Broome
Commenter Affiliation: Auto Industry Forum (AIF)
Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1
Comment Excerpt Number: 30

Comment: Numerous studies have been conducted to measure mercury in LFG, including several that were conducted for EPA. The table that accompanies these comments at Attachment E (attached to these comments) lists the test methods used in these studies and the methods specified in Table 6, and, for each method, whether it was included in the Boiler MACT Reconsideration Proposal. This table shows that none of the methods used in the publicly available, published LFG studies for Hg, including those sponsored by EPA, were included in Table 6 of the reconsideration proposal. Conversely, none of the LFG studies for Hg relied on the methods in Table 6.

This examination of fuel testing methods clearly indicates that EPA should expand Table 6 to include additional options for measuring Hg in gaseous fuels. At a minimum, EPA should include the methods tested and proven reliable in LFG studies for Hg, particularly EPA Method 30B and EPA Method 1631. The Agency may also want to consider including stack sampling and analysis methods for Hg approved by EPA and the State of California—CARB Method 436, EPA Method 101 and EPA Method 29. Additionally, AIF recommends that the Agency consider and evaluate the accuracy, precision, selectivity and sensitivity of the methods currently included in Table 6, taking into account their applicability to gas fuels other than NG or RG. AIF's comments demonstrate the appropriateness of incorporating into the final reconsideration rule additional methods for gathering data as to the concentration of Hg in a gaseous fuel. AIF urges EPA to amend the reconsideration proposal accordingly.

Response: For a response to the request to include method 30B testing, see EPA-HQ-OAR-2002-0058-3449-A1, excerpt 12.

Commenter Name: Kerry Kelly
Commenter Affiliation: Waste Management (WM)
Document Control Number: EPA-HQ-OAR-2002-0058-3681-A2
Comment Excerpt Number: 25

Comment: Method 30B is a stack gas method approved for the characterization of Hg in various off-gas sources, including incinerators, boilers, and other thermal devices. EPA has conducted collection of LFG using Method 30B with success and has used that test data in its 2008 Background Information Document for developing revised AP-42 emission factors for municipal waste landfills. (EPA/600/R-08-116. September). Some advantages of using Method 30B include:

Point source sampling can be conducted using relatively easy to operate and portable instruments;

- The sampling technology is mature and familiar to most well-trained sampling technicians;
- Analysis of samples is relatively inexpensive, and uses a standard EPA methodology;

- Quality assurance/quality control and comparability of data are easily monitored; and
- Data may be validated using standard auditing practices.

WM recently conducted a field study using Method 30B and ASTM D5954 for several projects supplying LFG as fuel to industrial boilers to demonstrate the viability of both applications. We evaluated the sampling and analysis of LFG using Method 30B by employing both an Ohio Lumex mercury analyzer, and by digestion of the sampling tube fractions followed by analysis using Method 7470B (CVAA). The results of the Method 30B analysis range from 0.2 to 1.9 ug/m³, which are consistent with results presented in the published literature previously identified in our comments and validate that mercury concentrations in LFG are well below the fuel specification for other gas 1 fuels.

Response: For a response to the request to include Method 30B testing, see EPA-HQ-OAR-2002-0058-3449-A1, excerpt 12.

Commenter Name: Barry Christensen

Commenter Affiliation: Occidental Chemical Corporation (OCC)

Document Control Number: EPA-HQ-OAR-2002-0058-3477-A1

Comment Excerpt Number: 6

Comment: OCC recommends a broader selection of methods for conducting the sampling and analysis of gaseous fuels.

We provided the required gas sampling methods specified in the final rule to three commercial testing companies. After consulting with their laboratories, they all declined to provide quotations for Gas 2 fuel (hydrogen) sampling using the required methods specified in Table 6. One of the primary reasons cited is the safety concern of sampling an explosive gas mixture. A much safer option would be to allow operators to conduct a one-time stack test for mercury by Method 29 or 30 on a process heater or boiler stack. Also, in a few cases, where a fuel gas can be vented to the atmosphere (e.g. hydrogen), alternative sampling options are available. Existing sampling Methods 101 and 102 for mercury testing should also be an allowed option, in addition to those methods specified in Table 5.

Response: The EPA recognizes the safety concerns of Hydrogen containing fuels and encourages the commenter to seek a lab accustomed to handling such materials. Stack testing for mercury is also a requirement of Table 5. Fuel sampling for mercury using EPA test methods may be problematic on Gas 2 fuels as the low molecular weight of hydrogen may require detailed recalibration of equipment. Additionally, hydrogen containing fuel gas may become explosive if exposed to standard stack testing equipment. We have allowed sampling of Gas 2 fuels with Silonite coated evacuated “bombs” in the recent Refinery ICR testing and such containers may be used pending approval of the administrator, as hydrogen is known to leak from conventional Tedlar bag samples.

Commenter Name: Lee Zeugin and Lauren Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1

Comment Excerpt Number: 40

Comment: EPA proposes some changes to § 63.7521 that are responsive to UARG's comments. For the fuel analysis plan submitted prior to the initial demonstration, EPA makes clear that the information must be provided only for "anticipated" fuel types. Proposed § 63.7521(b)(2).

Response: The EPA agrees with the commenter and has modified the rule language as appropriate.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 29

Comment: *EPA Should Provide a Liquid HCl Emission Limit Compliance Alternative Similar to that in the MATS Rule*

In the final MATS rule, EPA provided the following alternative to measure oil fuel moisture for ongoing compliance with HCl and hydrogen fluoride (HF) emission limits for liquid fired units at §63.10005:

(i) Liquid-oil fuel moisture measurement. If your EGU combusts liquid fuels, if your fuel moisture content is no greater than 1.0 percent by weight, and if you would like to demonstrate initial and ongoing compliance with HCl and HF emissions limits, you must meet the requirements of paragraph (i)(1)-(5) of this section.

(1) Measure fuel moisture content of each shipment of fuel if your fuel arrives on a batch basis; or

(2) Measure fuel moisture content daily if your fuel arrives on a continuous basis; or

(3) Obtain and maintain a fuel moisture certification from your fuel supplier.

(4) Use one of the following methods to determine fuel moisture content:

(A) ASTM D95-05 (Reapproved 2010), "Standard Test Method for Water in Petroleum Products and Bituminous Materials by Distillation," or

(B) ASTM D4006-11, "Standard Test Method for Water in Crude Oil by Distillation," or

(C) ASTM D4177-95 (Reapproved 2010), "Standard Practice for Automatic Sampling of Petroleum and Petroleum Products," or

(D) ASTM D4057-06 (Reapproved 2011) "Standard Practice for Manual Sampling of Petroleum and Petroleum Products."

(5) Should the moisture in your liquid fuel be more than 1.0 percent by weight, you must

(A) Conduct HCl and HF emissions testing quarterly (and monitor site-specific operating parameters as provided in §63.10000(c)(2)(iii) or

(B) Use an HCl CEMS and/or HF CEMS.

EPA discussed inclusion of the above alternative in the preamble to the MATS rule as follows:

The EPA is providing the alternative compliance assurance approaches in the final rule for liquid oil-fired EGUs of demonstrating compliance through either specific HCl or HF measurements or by demonstrating that the moisture content in the fuel oil remains at a level no more than 1.0 percent. The EPA is not aware of any FGD systems installed on oil fired EGUs. Thus, it is only the quality of the oil, and the level of HAP constituents contained therein, that can be relied upon for ensuring compliance.

Commenters refer to certain studies that provide a plausible reason for the chloride/fluoride contamination of fuel oils. We found this reason persuasive and accordingly are providing alternative compliance approaches in the final rule to demonstrate compliance with the acid gas HAP standards. Specifically, sources can demonstrate compliance through either specific HCl or HF measurements or by demonstrating that the moisture content in the fuel oil remains at a level no more than 1.0 percent. (77 Fed. Reg. 9402, February 16, 2012)

In addition, EPA provided further similar support and discussion of the compliance alternative in the Response to Comments documents for the final MATS rule in the document.11

All of the above reasoning and the approach provided by EPA for the MATS final rule are equally applicable to fuel oils utilized by boilers and process heaters subject to 40 CFR 63, Subpart DDDDD. Fuel oil utilized by industrial, commercial, and institutional (ICI) boilers and process heaters is the same commercial grade fuel oil as that used by electric generating units (EGUs), and there is no difference between those oil fuels relative to the potential for chloride content due to water. In addition, none of the Subpart DDDDD liquid subcategory HCl MACT floor units utilize acid gas controls. ACC strongly urges EPA to provide the same compliance flexibility to ICI fuel oil fired sources relative to compliance with the Subpart DDDDD HCl emission limit. With such a compliance alternative for HCl, the same ASTM test methods referenced in the MATS rule should also be incorporated by reference in Subpart DDDDD.

[Footnote 11: EPA's Responses to Public Comments on EPA's National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-Fired Electric Utility Steam Generating Units December 2011 Volume 1 of 2, p. 609-610, 726; and Volume 2 of 2, p. 60-61, 254.]

Response: We disagree with the commenter's suggestion to provide the same compliance flexibility to ICI oil-fired sources as provided by the EPA for the MATS final rule. The alternate compliance in MATS for oil-fired units allows the measuring of the moisture content in oil to demonstrate compliance with the HCl emission limit instead of measuring HCl emissions. In MATS, if moisture content of the oil is below 1%, the unit is deemed in compliance with the HCl emission limit. The reason for our disagreement is that, as part of the information collection conducted during the rulemaking, we have moisture and chlorine contents, and corresponding HCl emission data, for several oil-fired ICI facilities. Of these, 7 oil-fired ICI facilities had reported moisture content below 1% but 3 of these have HCl emissions above the existing MACT limit for HCl in the final rule, and 5 have HCl emissions above the new MACT limit for

HCl in the final rule. Therefore, the approach provided in MATS is not appropriate for subpart DDDDD.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 94

Comment: EPA should provide the same compliance flexibility to ICI fuel oil fired sources for compliance with the Subpart DDDDD HCl emission limit as EPA has provided in the utility MATS final rule. While Subpart DDDDD liquid HCl emission limit is also applicable to other liquid fuels, there is no rational reason to not provide the above alternative limited to fuel oils fired in ICI boilers and process heaters. With such an alternative, the same ASTM test methods should also be incorporated by reference in Subpart DDDDD.

All of the reasoning described below, and the approach provided by EPA for the utility MATS final rule, are equally applicable to fuel oils utilized by boilers and process heaters subject to 40 CFR63, Subpart DDDDD. Fuel oil utilized by ICI boilers and process heaters is the same commercial grade fuel oil as that used by electric utility units, so that there is no differentiation between those oil fuels relative to the potential for chloride content due to water.

In the final Utility MATS rule, 40 CFR Part 63, Subpart UUUUU -- National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units, EPA provided the following alternative to measure oil fuel moisture for ongoing compliance with HCl and HF emission limits for liquid fired units:

63.10005...

(i) Liquid-oil fuel moisture measurement. If your EGU combusts liquid fuels, if your fuel moisture content is no greater than 1.0 percent by weight, and if you would like to demonstrate initial and ongoing compliance with HCl and HF emissions limits, you must meet the requirements of paragraph (i)(1)-(5) of this section. (1) Measure fuel moisture content of each shipment of fuel if your fuel arrives on a batch basis; or

(2) Measure fuel moisture content daily if your fuel arrives on a continuous basis; or

(3) Obtain and maintain a fuel moisture certification from your fuel supplier.

(4) Use one of the following methods to determine fuel moisture content:

(A) ASTM D95-05 (Reapproved 2010), "Standard Test Method for Water in Petroleum Products and Bituminous Materials by Distillation," or

(B) ASTM D4006-11, "Standard Test Method for Water in Crude Oil by Distillation," or

(C) ASTM D4177-95 (Reapproved 2010), "Standard Practice for Automatic Sampling of Petroleum and Petroleum Products," or (D) ASTM D4057-06 (Reapproved 2011) "Standard Practice for Manual Sampling of Petroleum and Petroleum Products."

(5) Should the moisture in your liquid fuel be more than 1.0 percent by weight, you must

(A) Conduct HCl and HF emissions testing quarterly (and monitor site-specific operating parameters as provided in §63.10000(c)(2)(iii) or

(B) Use an HCl CEMS and/or HF CEMS.

EPA also incorporated by reference in the final Subpart UUUUU the following ASTM test methods applicable to the above compliance alternative:

§63.14 Incorporation by Reference.

* * * * *

(b) * * *

EPA discussed inclusion of the above alternative in the Preamble as follows:

2. Moisture Content of Oil

Comment: A number of commenters stated that studies suggest that chloride in fuel oil can result from contamination during transportation and processing of crude oils and then be emitted as HCl during combustion. For example, the commenters asserted that the chloride contamination of crude oils can occur as a result of the ballasting of tanker ships with seawater. However, the Oil Pollution Act of 1990 requires all new oil tankers to be double hulled and establishes a phase out schedule (by the middle of the decade) for existing single hulled tankers with un-segregated ballasts. Because of the role of seawater contamination in introducing contaminants into the oil, the commenters suggest that the EPA set a percent water content limit for fuel oil at a level of 1.0 percent, rather than setting HCl and HF emissions limits. This would encourage handling and transport practices to limit salt water contamination. One commenter recommended a standard of 1.0 percent water because several of the lowest HCl and HF emitting units currently require percent water (or water and sediment) specifications between 0.5 percent and 1.0 percent.

Response: The EPA is providing the alternative compliance assurance approaches in the final rule for liquid oil-fired EGUs of demonstrating compliance through either specific HCl or HF measurements or by demonstrating that the moisture content in the fuel oil remains at a level no more than 1.0 percent. The EPA is not aware of any FGD systems installed on oil fired EGUs. Thus, it is only the quality of the oil, and the level of HAP constituents contained therein, that can be relied upon for ensuring compliance.

In the proposal preamble, we stated:

We believe that chlorine may not be a compound generally expected to be present in oil. The ICR data that we have received suggests that in at least some oil, it is in fact present. EPA requests comment on whether chlorine would be expected to be a contaminant in oil and if not,

why it is appearing in the ICR data. To the extent it would not be expected, we are taking comment on the appropriateness of an HCl limit. See 76 FR 25045.

Commenters refer to certain studies that provide a plausible reason for the chloride/fluoride contamination of fuel oils. We found this reason persuasive and accordingly are providing alternative compliance approaches in the final rule to demonstrate compliance with the acid gas HAP standards. Specifically, sources can demonstrate compliance through either specific HCl or HF measurements or by demonstrating that the moisture content in the fuel oil remains at a level no more than percent.

In addition, the EPA provided further similar support and discussion of the compliance alternative in the Response to Comments documents for the final MATS rule:

EPA's Responses to Public Comments on EPA's National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-Fired Electric Utility Steam Generating Units December 2011 Volume 1 of 2, p. 609-610, 726; EPA's Responses to Public Comments on EPA's National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-Fired Electric Utility Steam Generating Units December 2011 Volume 2 of 2, p. 60-61, 254.

The data from the liquid units setting HCl floors (below) shows the compliance alternative is equally appropriate for these units. As with the MATS units, liquid units setting HCl floors for IB MACT have no acid gas controls, and therefore emission limits are achieved due to the fuels combusted. [See submittal for Table.]

Response: See the response to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 29.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 135

Comment: FUEL ANALYSIS OF GASEOUS FUELS AT CO-FIRED UNITS

ACC agrees with EPA's determination that no fuel analysis for chloride is required for gases and that operators are not required to conduct the mercury fuel specification analyses for gaseous fuels that are natural gas, refinery gas, or otherwise subject to another subpart of part 63.38 EPA also should exempt those sources using process gases that otherwise are regulated under Parts 60 and 61 from conducting a fuel specification analysis. Specifically, § 63.7521(f)(2) should be amended with the addition of the bold language noted to read:

"You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for gaseous fuels for units that are subject to another subpart of this part, part 60, or part 61."

EPA has already extended the exemption for boilers serving as control devices to those controlling gaseous streams subject to Parts 60 and 61. [Footnote 38: 76 Fed. Reg. at 80633, to be codified at § 63.7521(f)(1)-(2).]

Response: We agree that the fuel specification analysis should not be required for gaseous fuels that are subject to another standard. In the final rule, the definition of "Gaseous fuel" has been revised to clarify that off-gases regulated by another standard are exempt from the definition, and, thus, a source would not be required to conduct fuel analysis on that exempted offgas.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 136

Comment: § 63.7510(a)(2)(iii) appears to require mercury fuel analysis for natural gas:

"You are not required to conduct a chlorine fuel analysis for any gaseous fuels. You must still conduct a fuel analysis for mercury on gaseous fuels unless the fuel is exempted in paragraphs (a)(2)(i) through (iii) of this section."

EPA should clarify this paragraph to indicate that mercury analysis is also not required for natural gas or refinery gas.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 135.

Commenter Name: Richard Krock

Commenter Affiliation: The Vinyl Institute

Document Control Number: EPA-HQ-OAR-2002-0058-3526-A1

Comment Excerpt Number: 11

Comment: EPA Should Add Alternative Methods for the Fuel Gas Specification

EPA has proposed, in Table 6 of the proposed rule, the analyses required to qualify a gaseous fuel other than natural gas or refinery gas as a Gas 1 fuel. We are concerned that stack testing companies and their laboratories may not be able to provide the required sampling and testing specified in Table 6, and indeed understand that one of our member companies found this to be true for Gas 2 fuel (hydrogen). As an alternative to the proposed methods, EPA should allow the affected source to conduct a one-time stack test for fuel gases that can be vented, such as hydrogen gas, if it can be done safely. Otherwise, the VI recommends that an option be incorporated that allows a onetime stack test for mercury on the affected boilers or process heaters as a substitute for less safe fuel gas sampling. This stack test could be conducted using the methods specified in Table 5 or, alternatively, sampling Methods 101 and 102 for mercury testing. These alternatives would meet EPA's intent to allow clean gases to qualify as Gas 1 fuels while acknowledging the current limitations of laboratory capabilities and sampling services.

Response: The final does prohibit the use of other methods than those listed in Table 6. Table 6 list methods to be used but also allows for the use of "equivalent" test methods. What is meant by an equivalent test methods is defined in 63.7575.

Commenter Name: Shannon S. Broome

Commenter Affiliation: Auto Industry Forum (AIF)

Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1

Comment Excerpt Number: 29

Comment: *EPA Should Amend the "Other Gas 1 Fuel" Specification Analysis to Make It More Feasible and Allow for Use of Additional Test Methods.*

The reconsideration proposal appears to prevent gaseous fuel suppliers from using alternative test methods, which are available for use by the boiler owner/operator if they conduct the requisite analysis for using an "other Gas 1 fuel." *See Boiler MACT Reconsideration Proposal*, 76 Fed. Reg. at 80,633 (proposed § 63.7521(g)(2)(vi)). EPA provides no explanation or rationale for this inflexible requirement. While, in the context of the Boiler MACT, AIF members are gaseous fuel purchasers – not suppliers – it appears likely to affect the majority of fuel specification analysis. This is because it is likely that purchasers of gaseous fuels will require their fuel suppliers to develop the fuel specification analyses and documentation necessary to qualify fuels as in "other Gas 1 fuel" category. Accordingly, AIF urges EPA amend the language at § 63.7521(g)(2)(iv) so that all analyses conducted for the demonstration mechanism may utilize all methods listed in § 63.7521(f)-(i). AIF requests that EPA incorporate additional test methods for use under § 63.7521. That subsection limits the fuel testing to qualify a gaseous fuel other than NG or RG as an "other Gas 1 fuel" to methods laid out in Table 6. *See id.* Table 6 requires measurement of the Hg concentration through one of the following test methods: "ASTM D5954, ASTM D6350, ISO 6978–1:2003(E) or ISO 6978–2:2003(E) (or an equivalent test method)." *See id.* at 80,666. EPA requires use of these methods unless it specifically approves an alternative analytical method. *See id.* at 80,633 (proposed § 63.7521(g)(v)). EPA offers no explanation as to why it failed to include EPA Method 30B, the method it prescribed for facilities, including those owned and/or operated by AIF members, to use in gathering the Hg data supplied to EPA in response to its Section 114 requests.

The required test methods listed in Table 6 were developed for NG analyses and their use is typically restricted as such. They have not been proven appropriate for analyzing, *e.g.*, Hg in LFG and the composition and physical properties of LFG differ from those of NG.¹⁸ Further, as gaseous fuel suppliers are not allowed to use alternative methods in the reconsideration proposal, the regulations would force them to use – and gaseous fuel purchasers like AIF's members to rely on – an unproven method to demonstrate the compliance of gaseous fuels like LFG with the Hg fuel specification. The complexity of component fuels typically encountered in sampled LFG often renders the methods typically used for NG characterizations inappropriate.¹⁹ As reported by Waste Management, a supplier of LFG, the performance of these methods in an LFG matrix has yet to be demonstrated. As a result, there is no rational basis for EPA to categorically restrict fuel analysis for gaseous fuels like LFG, in the absence of a pre-approval process, to the four methods listed in Table 6. [Footnote 18: For example, NG is primarily methane with lower concentrations of related alkanes and carbon oxides, and trace quantities of other hydrocarbons. LFG typically contains 45% to 60% methane and 40% to 60% carbon dioxide. LFG also includes small amounts of nitrogen, oxygen, ammonia, sulfides, hydrogen, and carbon monoxide.]

[Footnote 19: Either interferences or target analyte levels may disqualify natural gas methods when attempting to acquire representative Hg data in LFG.]

Response: See the response to comment EPA-HQ-OAR-2002-0058-3449-A1, excerpt 12 regarding Method 30B. See the response to comment EPA-HQ-OAR-2002-0058-3526-A1, excerpt 11 regarding the use of alternative methods to those in Table 6.

Commenter Name: Edward W. Repa

Commenter Affiliation: National Solid Wastes Management Association (NSWMA)

Document Control Number: EPA-HQ-OAR-2002-0058-3539-A1

Comment Excerpt Number: 6

Comment: Under Section 63.7521(g)(2)(vi), gas fuel suppliers appear to be prevented from using alternative test methods that are available to the boiler owner/operator. A rationale is not provided for such a requirement considering that a supplier is the one that will likely be tasked with performing the test.

The Landfill Institute recommends that EPA remove this requirement to allow suppliers to use alternative methods. We further recommend that EPA incorporate EPA test method 30B because it is more appropriate for LFG. This is the same test method used by EPA to determine Hg concentrations by EPA's Office of Research and Development.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3449-A1, excerpt 12 in regards the use of Method 30B. See the response to comment EPA-HQ-OAR-2002-0058-3526-A1, excerpt 11 in regards to using other methods than those listed in Table 6.

Commenter Name: Sarah Hedrick

Commenter Affiliation: Verso Paper Corp.

Document Control Number: EPA-HQ-OAR-2002-0058-3537-A2

Comment Excerpt Number: 2

Comment: The proposed rule outlines that fuel samples for Hg and HCl analysis must be obtained following the requirements of 63.7521(c)(1)(ii). This specifically requires fuel samples be collected at one hour intervals during the testing period for sampling during a performance test. This requirement is not practical. Performance testing does not work in a seamless, clockwork fashion. Performance testing involves discrete one-hour or longer runs. Each run is followed by an interval to collect and preserve samples and prepare for the next run. People conducting performance tests also need to take rest breaks. As written, this requirement is far too inflexible and stringent; it cannot be implemented in the real world. Furthermore, collecting fuel samples from belts and other moving equipment requires planning and execution, while adhering to safe practices such as lock out-tag out / zero potential energy procedures. These essential safety measures conflict with the clockwork requirements specified in the rule. The wording in the rule simply needs to be changed to allow samples to be safely collected contemporaneous with the stack test.

Response: The EPA agrees with the commenter and has modified 63.7521(C)(1)(ii) to read "Each composite sample will consist of a minimum of three samples collected at approximately equal one-hour intervals during the testing period for sampling during performance stack testing where safety permits. If equipment operations, lock out procedures, or other safe work practices preclude simultaneous fuel sampling with the testing make arrangements to provide for

composite fuel samples that are representative of the fuel burned during each performance test. For monthly sampling, each composite sample shall be collected at approximately equal 10-day intervals during the month."

Commenter Name: Sarah Hedrick

Commenter Affiliation: Verso Paper Corp.

Document Control Number: EPA-HQ-OAR-2002-0058-3537-A2

Comment Excerpt Number: 3

Comment: The proposed rule is too rigid in specifying monthly sampling requirements, in that each composite sample must be collected at approximately equal 10-day intervals during the month. This is not a practical requirement which can be implemented to such literal intent. The 10th day could be outage day. The 10th day could be a weekend day where it is not safe and practical to collect a sample, due to reduced staffing. The wording in the rule should simply specify that evenly spaced samples be collected.

Response: The EPA does not agree with the commenter that the wording of "approximately equal 10-day intervals during the month" is too rigid.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 105

Comment: Consistent with the general exclusion for control devices, fuel analyses should not be required for gaseous fuels regulated by parts 60, 61, 63, or 65. Additionally, the proposed wording of proposed §63.7510(a)(2)(ii) is confusing and should be revised. Proposed §63.7510(a)(2)(ii), last sentence provides:

... If gaseous fuels other than natural gas, refinery gas, or other gas 1 fuels are cofired with other fuels and those gaseous fuels are subject to another subpart of this part, you are not required to conduct a fuel analysis of those fuels according to §63.7521 and Table 6 to this subpart.

As discussed in Comment II.1.F energy recovery of regulated gases should be encouraged and BPH used as control devices should be excluded from BPH NESHAP requirements. Proposed §63.7510(a)(2)(ii) only excludes from the co-fired fuel analysis requirements gaseous fuels subject to other part 63 subparts. We believe this exclusion should be extended to gaseous fuels regulated under parts 60, 61, and, to avoid confusion as more and more subparts reference part 65, to part 65 as well. **We recommend the last sentence of §63.7510(a)(2)(ii) be revised as follows:**

... Fuel analyses is not required for gaseous fuels regulated by subparts of part 60, 61, 63 or 65 of this chapter that are co-fired with Gas 1 or other Gas 1 fuels.

Response: We disagree that a revision is necessary. Paragraph 63.7510(a)(2)(ii) reads "If gaseous fuels other than natural gas, refinery gas, or other gas 1 fuels are co-fired with other

fuels and those gaseous fuels are subject to another subpart of this part, part 60, part 61, or part 65, you are not required to conduct a fuel analysis of those fuels according to §63.7521 and Table 6 to this subpart."

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 106

Comment: Proposed §63.7521(f)(2) provides:

You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for gaseous fuels that are subject to another subpart of this part.

For the reasons discussed in Item 1 above, we believe this exclusion should also be extended to gaseous fuels regulated under parts 60, 61, and, to avoid confusion as more and more subparts reference part 65, to part 65 as well.

We recommend §63.7521(f)(2) be revised as follows:

You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for gaseous fuels that are subject to another subpart of this part or a subpart of parts 60, 61 or 65 of this chapter.

Response: We agree and paragraph 63.7521(f)(2) has been revised to read "You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for gaseous fuels that are subject to another subpart of this part, part 60, part 61, or part 65."

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 107

Comment: Fuel analysis should be allowed for showing compliance with the HCl limit for Gas 2 subcategory BPH.

Proposed §63.7505(c) specifies that "For gaseous fuels, you may not use fuel analyses to comply with the total selected metals alternative standard or the hydrogen chloride standard." No explanation for this restriction is provided in the preamble.

Determining the chloride content of gases is straightforward and any chloride reaching the burners would be expected to convert to HCl. In the many cases where the standard is being met without the use of controls, fuel analysis is a straightforward and much less burdensome approach to demonstrating compliance than is stack analysis. Thus, we strongly encourage EPA to allow fuel analysis for HCl compliance demonstrations. If a source's gas 2 fuel meets the HCl emission limit based on the fuel chloride content, there is no concern about whether any chloride

is removed in the control system (if any). On the other hand, if the fuel contains enough chloride that the HCl emission limit is not being met, the source would have to do stack testing to demonstrate that the controls are adequately removing chloride.

Response: In the March 2011 final rule, we originally examined the possibility of basing the demonstration of process gases being similar to Gas 1 on levels of mercury and chlorine content in the gases. However, we found no proven test methods were identified to quantify chlorine content of natural gas. Therefore, the EPA disagree with revising 63.7505(c) to allow fuel analysis of gaseous fuel.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 108

Comment: The final rule should be clear that initial performance tests are not required if fuel analysis is used as the initial compliance demonstration for HCl and Hg limits.

While it appears the rule text allows for companies that are using fuel analyses to demonstrate compliance with the HCl and Hg limits to not perform performance testing for the initial compliance demonstration, the preamble language of the proposed rule (see page 80602) seems to indicate that performing testing IS required. The final rule language needs to clearly indicate that performance testing is NOT required for companies that elect to demonstrate compliance with the HCl and Hg limits using fuel analyses.

Response: It is the rule language that applies and this is clearly stated in 63.7505(c).

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 109

Comment: Approval should not be required for the site-specific fuel monitoring plan unless alternative analytical methods are being requested.

Proposed §63.7521(b) and (g) require submission and approval of a site-specific fuel analysis plan for review and approval. This plan must be submitted no later than 60 days before the date you plan to conduct the initial compliance demonstrations. There are likely to be API/AFPM Comments on Proposed BPH NESHAPs, CISWI and NHSM Rules Page 78

thousands of such submissions (Table 5 of the preamble estimates 2200 existing BPH subject to numerical emission limits), since fuel analysis is anticipated to be widely used. It is highly unlikely all these plans can be reviewed before the initial compliance date and, unless the source is deviating from the methodologies specified in the rule, there is no reason for such a review.

Thus, we recommend that approval only be required where the source is requesting to use an alternative analytical methodology.

Furthermore, relative to Table 6 methodologies, the proposal allows use of "equivalent" methodologies and defines "equivalent" for this purpose in proposed §63.7575. EPA should clarify in §63.7521(b) and (g) that no further approvals are required for methodologies that meet the definition of equivalent.

Response: Paragraph 63.7521(b) of the final rule has been revised to require submittal of the site-specific fuel analysis plan for review and approval if an alternative analytical method is requested to be used than those listed in Table 6 of the final rule.

11Z. Out of Scope: Testing and Monitoring

Commenter Name: Dakota Gasification Company Great Plains Synfuels Plant

Commenter Affiliation: David W. Peightal

Document Control Number: EPA-HQ-OAR-2002-0058-3424

Comment Excerpt Number: 4

Comment: EPA should allow the sources that choose to demonstrate compliance with stack testing in lieu of CEMS, to have as many performance tests as deemed necessary and have rolling average of all the test results during the first twelve months of operating hours to demonstrate compliance with the final emissions standards. This would minimize unnecessary enforcement issues and allow the affected sources to adjust the operations of the boilers or process heaters as deemed necessary during the initial twelve months of compliance demonstration.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Shannon S. Broome

Commenter Affiliation: Auto Industry Forum (AIF)

Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1

Comment Excerpt Number: 3

Comment: The recently-promulgated MATS rule for utility boilers provides several methods of demonstrating compliance for each regulated pollutant or surrogate. One option is to conduct quarterly stack testing. For the most part, no other ongoing parametric monitoring is needed when the stack test option is selected. EPA explains in the preamble that "we removed the other operating limits for control devices based on a review of the comments, after considering other programs in place to ensure proper. 41 operations of controls at EGUs." 77 Fed. Reg. 9384. The basic idea is that enough monitoring is already required under other CAA and state emission standards (and operators always have the goal of energy efficient operation) that EPA already has assurance that the unit will be well operated between the quarterly stack tests.

A similar approach would be justified under the Industrial Boiler MACT and could help resolve the problems described above with the CO stack test limit for units with a high level of

operational variability. In short, if compliance with the CO limit were based solely on quarterly stack tests – with no parametric monitoring in between tests – then affected sources would be better able to ensure compliance because they would judge compliance based on frequent stack testing using the same method and under the same conditions as used during the stack tests used to set the standard – *i.e.*, such an approach would ensure a true "apples to apples" compliance method. No parametric monitoring is needed between stack tests because affected sources have a powerful incentive to maintain efficient combustion conditions. Doing so minimizes the amount of fuel consumed, which typically is the largest cost (by far) of operating an industrial boiler. Since maintaining efficient combustion conditions would minimize CO emissions, EPA will have assurance that CO is well controlled on a continuous basis.

For units that already have CO CEMS for reasons unrelated to the Industrial Boiler MACT, this approach would have to be implemented in conjunction with a determination that CEMS data cannot be used to show compliance with the stack test limit, as described more fully above.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Dean C. DeLorey

Commenter Affiliation: The Amalgamated Sugar Company LLC (TASCO)

Document Control Number: EPA-HQ-OAR-2002-0058-3522-A1

Comment Excerpt Number: 10

Comment: The rule mandates PM CEMs for specific solid fuel boilers. It is our understanding that PM CEMs are extremely unreliable. Mandating unreliable monitoring equipment is not appropriate. Please delete this requirement.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 98

Comment: Other regulations support a 5-year testing cycle. For example, 40 CFR §75 requires low mass emissions units to establish NOx emissions curves based on testing conducted every 5 years. Several states require that testing be conducted upon each 5-year Title V permit renewal. All affected major sources subject to Boiler MACT are required to have Title V Permits. The Title V permitting program provides the appropriate vehicle to implement a 5-year test requirement.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 99

Comment: The CEMS QA/QC requirements established by EPA are confusing and extremely burdensome to sources. For example, many industrial boilers and process heaters are subject to a variety of federal and state regulations. The federal and state regulations often require slightly different data reduction requirements and QA/QC for CEMS systems. Another issue is the practical matter of needing to train personnel how to address a data signal, which can be different depending what rule is applicable. CIBO restates by reference here its position set forth in the Petition for Reconsideration, which includes a detailed discussion of the burdens associated with the CEMS QA/QC requirements and a description of a more reasonable and defensible methodology.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: J. Michael Geers

Commenter Affiliation: Duke Energy

Document Control Number: EPA-HQ-OAR-2002-0058-3543-A1

Comment Excerpt Number: 18

Comment: Operating Limits Should Not Be Required In Circumstances Where Continuous Emissions Monitors Are Utilized

In cases where PM monitors, mercury CEMS, HCl or SO₂ CEMS used to demonstrate compliance with PM, mercury or acid gas limits, EPA should not require the establishment of and compliance with operating limits. Because the source is directly measuring the specific emission, or its surrogate, the monitoring of operating parameters serves no useful purpose.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Annabeth Reitter

Commenter Affiliation: NewPage Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3662-A2

Comment Excerpt Number: 12

Comment: Several NewPage facilities have situations where multiple boilers vent through a common stack. These situations involve solid fuel (coal and biomass) boilers and/or natural gas boilers that share a common stack. In the proposed reconsideration rule, EPA is proposing a number of monitoring requirements for solid fuel units involving opacity monitoring, PM CPMS, and the possible use of other continuous pollutant monitoring systems for determining compliance with the standards. These monitoring devices will most likely be located on the common stack. Units that share a common stack may have situations where one or more of the units maybe in a startup or shutdown mode while the other unit(s) continue to run. In this situation, for example, compliance with an opacity standard as a surrogate for PM/HAPs may be difficult and depending on the circumstances may not be achievable. In the reconsideration

proposal, EPA has not addressed situations when one or more boilers that vent through a common stack are in a startup or shutdown mode while other boiler(s) that also vent through that common stack continue to run. Provisions for common stacks need to be included so as not force a source into a potential noncompliance situation as a result of routine operating modes.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Robin Mills Ridgway

Commenter Affiliation: Purdue University

Document Control Number: EPA-HQ-OAR-2002-0058-3668-A2

Comment Excerpt Number: 17

Comment: In the Utility MACT, EPA allows existing sources with acid gas controls to comply with an SO₂ limit in lieu of an HCl limit (77 FR 9490, Table 2 (1)(b)). With the upcoming SO₂ NAAQS implementation timing (2017) being very close to Boiler MACT compliance (2015), many industrial sources are not only evaluating compliance with the Boiler MACT but also looking toward compliance with SO₂ SIPs. Allowing a source an alternate of an SO₂ limit could encourage sources to make best use of capital dollars and invest in equipment that is most likely to address both HCl and SO₂. Purdue proposes that an alternate to HCl for industrial boilers be NSPS SO₂ at 0.2 lb/MMBTU or 90% SO₂ reduction at max 1.2 lb/MMBTU.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 114

Comment: The ambiguous flow and pressure instrument requirements are not needed and should be deleted. At a minimum, they must be clarified and made consistent with good engineering practice and standard instrument practice.

Proposed §63.7525(e) and (f) specify requirements for flow and pressure CMS. It is unclear whether standard instrumentation installations can meet these requirements. The Agency has not made a case that these concerns occur or occur frequently enough to require installation of new, non-standard systems. EPA should specify the requirements clearly, explain why these are concerns and how frequently these concerns impact flow and pressure measurements, how it expects sources to comply, and identify and consider the costs and burdens associated with adding additional equipment or modifying existing standard installations. If adequate justification for the costs cannot be presented these requirements must be deleted.

Specific requirements that must be addressed include the following. In general we believe all of these requirements, if finalized, should be limited to what is required by good engineering practice.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 115

Comment: How do you minimize the effects of swirling flow or abnormal velocity distributions (§63.7525(e)(3))? Must piping be revised to provide straight runs before and after the meter? If so, of what length? What does "minimum" mean? Does it mean none? Does it mean the minimum practical? Does it mean the minimum needed to assure representative samples? Does it mean the minimum consistent with good engineering practice? What is an "abnormal" velocity distribution?

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 116

Comment: How do you minimize pulsating pressure, vibration, and corrosion (§63.7525(f)(3))? Are exotic alloys required to minimize corrosion? Does external rust count? How much rust is allowed? How do you minimize "pulsating pressure"? How much of a pressure change over what timeframe is considered "pulsating"? Does external vibration count (e.g., from a nearby engine, from trucks going by)? Does this requirement mean no pulsation, vibration or corrosion is allowed? Does it mean minimum practical? Does it mean the minimum consistent with good engineering practice?

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Kerry Kelly

Commenter Affiliation: Waste Management (WM)

Document Control Number: EPA-HQ-OAR-2002-0058-3681-A2

Comment Excerpt Number: 32

Comment: WM recommends that affected facilities be allowed the flexibility to conduct more than just three stack test runs to demonstrate compliance with applicable limits. Given the wide variety of fuels that boilers may combust, providing flexibility for more than three stack test runs allows for some variability among individual stack test runs while also ensuring the stack test average is below the limit for verification of long term performance and low emission levels. We

suggest the following language be incorporated in the final rule: “You must conduct a minimum of three separate test runs for each performance test required in this section as specified in 63.7(e)(3)... The average of 3 or more test runs shall be used to determine compliance with the emission limits.” This option to use more than three test runs would be specified in the site specific test plan under 63.79 (c). It could be limited to total metals and HCl where variability is more likely to occur in various fuel combinations.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Dean C. DeLorey

Commenter Affiliation: The Amalgamated Sugar Company LLC (TASCO)

Document Control Number: EPA-HQ-OAR-2002-0058-3522-A1

Comment Excerpt Number: 13

Comment: It is requested that continuous emissions monitoring of PM and CO be eliminated. With reduced monitoring, the record keeping and reporting requirements should be adjusted accordingly.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

110A. Testing Frequency [DENIED PETITIONER ISSUE]

Commenter Name: Russell A. Wozniak

Commenter Affiliation: The Dow Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3449-A1

Comment Excerpt Number: 19

Comment: Dow supports a reduced frequency of subsequent performance tests, but further comments that testing for light liquid, heavy liquid, and Gas 2 fueled sources should only be required once every five years.

Sections 63.7515(b) of EPA’s proposed rule requires annual retesting until such time that two consecutive annual tests are conducted with all emissions less than 75% of the emission limit. Then, the rule allows for re-testing essentially every three years.

EPA provides no justification in the preamble for requiring annual retesting for sources fueled by liquid or Gas 2 fuels. Annual retesting is an unnecessary and burdensome requirement. Emission testing is costly and it must be coordinated with necessary plant operations and the availability of testing contractors. None of these factors are trivial and such frequent testing for low HAP emission rates is not needed. One of the most strenuous MACT standards, the Hazardous Waste Combustion MACT Section 63.1207(d)(1), requires initial retesting after five years. A number of the MACT Standards do not include retesting requirements unless the source is modified in a manner that would adversely affect compliance with the emission standard. Therefore, we urge EPA to further revise the rules to require testing on a five year frequency.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Randall D. Quintrell

Commenter Affiliation: Georgia Paper & Forest Products Association

Document Control Number: EPA-HQ-OAR-2002-0058-3451-A1

Comment Excerpt Number: 6

Comment: The requirement for annual compliance testing also is unwarranted, especially for the myriad of parameters required. As we stated in our prior comments, submitted during the comment period for the March 2011 rule, the stack testing requirements proposed are tremendously expensive, resource intensive, difficult to accomplish, and unnecessary. We reiterate all our prior comments on this topic by reference.

The purpose of an initial performance test (IPT) is to demonstrate that the technology chosen has the ability to meet compliance, and parametric monitoring is established at that time to continue to show that the control technology remains in good operating condition over time. Repeat testing is unnecessary as long as the operating conditions are stable and the parametric monitoring shows that the control device remains within its demonstrated performance range. EPA should reconsider this requirement and the compliance testing should be changed to an initial performance test only. This approach has worked well for prior MACTs, and there is no reason to change it for this rule. If repeat testing is deemed necessary, it should be limited to no more often than once/ five years. Annual testing is a waste of resources - including EPA's, the State agencies', and the affected facilities'.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Claudia M. O'Brien, Latham & Watkins LLP

Commenter Affiliation: JELD-WEN, inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3485-A1

Comment Excerpt Number: 14

Comment: While EPA has proposed a minor revision to the testing frequency for cases where MACT floors were lower than three times the RDL value, EPA retained the general requirement that a source conduct all applicable performance tests on an annual basis. This testing frequency is overly burdensome.

EPA enerally requires that a source conduct all applicable performance tests on an annual basis. The one exception to this requirement, permitting testing "every 3 years, instead of annually, if measured emissions during 2 consecutive annual performance tests are less than 75 percent of the applicable emission limit,'42 is not sufficient to alleviate the overly burdensome nature of the annual testing requirement. JELD-WEN recommends that EPA reconsider the annual source testing requirement for sources which use a control device to demonstrate compliance with the emission limits, sources for which the initial compliance test demonstrates compliance with the emission limits, and sources which bum clean fuels.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Claudia M. O'Brien, Latham & Watkins LLP

Commenter Affiliation: JELD-WEN, inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3485-A1

Comment Excerpt Number: 15

Comment: The cost burden imposed by the annual source testing requirement in the Boiler MACT rule is overly burdensome and unnecessary. Currently, most Title V sources are only required to perform source tests once every five years (once per permit term). Thus, the estimated cost (between \$20,000 and \$30,000 per test) averages out to between \$4,000 and \$6,000 per year over the permit term. In contrast, when a unit is required to perform source tests annually under the Boiler MACT rule, this will effectively increase the annual source testing costs from \$6,000 a year to \$30,000 a year. The annual source testing cost would be in addition to any annual operating costs associated with using a control device to demonstrate compliance with the emission limits. This additional cost burden imposed on industry is significant and it is unclear whether EPA took annual testing costs into consideration when looking at the financial burden to the industry. Furthermore, while the Boiler MACT allows for demonstrating compliance with the HCl and Mg limits by performing fuel analysis, it requires that the analysis must be performed every month. Monthly fuel analysis is costly and unnecessary if the fuel source does not change from the original fuel sampling and analysis.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Arthur N. Marin

Commenter Affiliation: Northeast States for Coordinated Air Use Management (NESCAUM)

Document Control Number: EPA-HQ-OAR-2002-0058-3506-A1

Comment Excerpt Number: 22

Comment: In its reconsideration of the final major source rule, the EPA is proposing to require that all sources subject to the rule undergo PM emissions tests at regular intervals (i.e., at least every five years, in most cases). The NESCAUM states believe that a properly maintained and tuned unit that burns light liquid fuels and that has been initially tested for PM emissions can rely on periodic tune-ups and maintenance to remain clean through its lifetime. Therefore, these scheduled testing requirements will be unnecessary for smaller units (<50 MMBtu/h) burning cleaner fuel types, and we request that the EPA remove PM testing requirements after the initial test for these units.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Michael L. Krancer

Commenter Affiliation: Pennsylvania Department of Environmental Protection (DEP)

Document Control Number: EPA-HQ-OAR-2002-0058-3507-A1

Comment Excerpt Number: 20

Comment: In the final rule the EPA changed the stack testing requirements to allow units that demonstrate compliance for a particular pollutant at a level at or below 75 percent of the emission limit for two consecutive years to forgo stack testing for up to 37 months. The EPA intends to maintain this provision for most of the emission limits and is soliciting comments on this provision.

The DEP believes that reduced stack testing frequency is appropriate for units demonstrating compliance for a particular pollutant at a level at or below 75 percent of the emission limit for two consecutive years.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 134

Comment: REDUCED TESTING FREQUENCY AND DETECTION LEVELS

The Final Boiler Rule requires annual emissions testing (once every 13 months). See § 63.7515 (a). Facilities can conduct performance tests less often for a given pollutant if the performance tests for the pollutant for at least 2 consecutive years show that emissions are at or below 75 percent of the emission limit (or, in limited instances as specified in Tables 1 and 2, at or below the emission limit), unless they are using emissions averaging. See § 63.7515(b). While ACC does agree with EPA’s acknowledgement of the need for reduced stack testing frequency for units with emissions below the standards, the requirement for initial annual stack testing and for ongoing annual stack testing where emissions averaging is being used is unreasonable and out of character with other MACT and NSPS standards and other state performance testing requirements.

EPA has proposed the most aggressive performance testing requirements of which we are aware on the largest MACT source category it has addressed to date. By contrast, the Hazardous Waste Combustor MACT (Subpart EEE) requires a comprehensive performance test only once every 5 years. Many MACT standards and NSPS only require one initial performance test unless there is a physical change to the control device that would increase emissions. The purpose of the initial performance test is to ensure that the technology installed is capable of meeting the emission limits. EPA has proposed extensive monitoring and recordkeeping that is meant to ensure continuous compliance with the emission standards. If these extensive monitoring and recordkeeping provisions are finalized, the frequency of stack testing should be reduced to once every 5 years.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 112

Comment: The proposed rule requires annual emissions testing (once every 13 months). See 63.7515 (a). Facilities can conduct performance tests less often for a given pollutant if the performance tests for the pollutant for at least 2 consecutive years show that emissions are at or below 75 percent of the emission limit (or, in limited instances as specified in Tables 1 and 2, at or below the emission limit), unless emissions averaging is being used. See 63.7515 (b). While we do agree with EPA's acknowledgement of the need for reduced stack testing frequency for units with emissions below the standards, the requirement for initial annual stack testing and for ongoing annual stack testing where emissions averaging is being used is unreasonable and out of character with other MACT and NSPS standards and other state performance testing requirements. EPA has put forth the most aggressive performance testing requirements of which we are aware on the largest MACT source category it has addressed to date. The Hazardous Waste Combustor MACT (Subpart EEE) for example requires a comprehensive performance test only once every 5 years. Many MACT standards and NSPS only require one initial performance test (e.g., pulp and paper MACT standards under Subparts S and MM) unless there is a physical change to the control device that would increase emissions. Other MACT standards do not require more frequent testing where emissions averaging is being used.

The purpose of the initial performance test is to ensure that the technology installed is capable of meeting the emission limits. EPA has proposed extensive monitoring and recordkeeping that is meant to ensure continuous compliance with the emission standards. Therefore, the frequency of stack testing should be reduced to once every years, and facilities using the emissions averaging approach should also qualify for a reduced stack testing frequency.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Stephen E. Woock

Commenter Affiliation: Weyerhaeuser Company

Document Control Number: EPA-HQ-OAR-2002-0058-3523-A1

Comment Excerpt Number: 16

Comment: We are concerned with the performance testing requirements provisions requiring annual compliance testing, which add to the operating costs without a sound basis for their frequency or complexity. We appreciate that EPA's proposal does offer the potential for reduction from the annual testing frequency when certain compliance margins are demonstrated over periods of time. However, in reality this will bring little relief since it is unlikely to be achieved simultaneously for each of the eligible HAPs and therefore testing will have to continue for those HAPs not meeting the relief criterion. The frequency of stack testing should be reduced. The purpose of the initial performance test is to ensure that the technology installed is capable of meeting the emission limits. In addition to that initial performance test, EPA requires extensive monitoring and recordkeeping that is meant to ensure continuous compliance with the

emission standards. This monitoring should give EPA and the public the assurance needed to allow the stack testing requirements to be eliminated or reduced to once every 5 years after the initial performance test.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Bart Sponsellar

Commenter Affiliation: Wisconsin Department of Natural Resources (DNR)

Document Control Number: EPA-HQ-OAR-2002-0058-3527-A1

Comment Excerpt Number: 4

Comment: The proposed schedule of annual stack testing for sources subject to emission limitations, especially for smaller sources, is very intensive and costly. We encourage EPA to consider opportunities for consolidating compliance and testing requirements through the use of a carbon monoxide and oxygen continuous monitoring system with combustion trim (CO/O₂ CMS trim) — a non CEMs analyzer based monitoring system. This approach should be allowed as an alternative to the primary defined compliance demonstration requirements.

This approach continuously minimizes emissions and we believe can be allowed under the rule to meet start-up work practices, dioxin/furan work practices, and CO and PM parametric monitoring needs. EPA has acknowledged that an oxygen trim system alone is a better way to operate a boiler. The CO/O₂ CMS trim approach takes the next step in operating a boiler for combustion efficiency. We propose that this approach will allow for performance tests every two years and tune-ups every four years for sources. This is very important as Wisconsin sources are currently subject to biennial stack testing (as applicable). Going to this schedule and simplifying other requirements will significantly reduce the cost of this rule while resulting in the same or potentially better environmental improvement.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Bart Sponsellar

Commenter Affiliation: Wisconsin Department of Natural Resources

Document Control Number: EPA-HQ-OAR-2002-0058-3527-A2

Comment Excerpt Number: 26

Comment: The Department also believes that stack testing can be allowed on a biennial schedule for pollutants when sources are operating a positive control system for the pollutant in question. Specific cases we have identified where we believe biennial stack testing applies under positive control systems are as follows. The Department proposes that a CO CMS and good combustion trim system is positive control in reducing all organic toxics including dioxin and furans. EPA is proposing that particulate is a combustion based pollutant. Under this approach we believe that a source operating with good combustion (CO CMS) and ESP or fabric filter systems is a positive control system for both PM and non-mercury metals. In this case the source should be able to monitor the necessary parameters and stack test every two years for PM or metals. The Department also believes this approach constitutes an option equal to a PM CMS

compliance demonstration. The Department believes that a similar approach and biennial stack testing schedule can be taken for mercury controlled by activated carbon injection and for hydrogen chlorides controlled by either dry or wet scrubbing. To simplify this option, EPA can allow a source to demonstrate a correlation between the pollutant of interest and the positive control measure. If necessary this correlation can be approved by the delegated authority.

The Department also suggests EPA consider that a CO CMS system with good combustion trim requirements basically constitutes continuous tuning of the source. Along with biennial stack testing the CO CMS trim system is checked every two years. Under this monitoring approach, the Department believes that tune-ups are only necessary every four years. This schedule coincides with the time frame EPA suggests for inspecting burners and other boiler system equipment.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 95

Comment: EPA should modify the finalized emission testing requirements so that they are consistent with the 5 year Title V permit review cycle. Annual compliance testing is extremely expensive and the benefits of conducting emission tests more frequently than every 5 years do not justify the costs. In addition, as noted in CIBO’s Petition for Reconsideration, there is likely to be a shortage of testing and laboratory resources under the current emission testing schedule.

CIBO appreciates the change in the frequency of performance testing from annually in the final rule to once every three years in the reconsideration rule. However, requiring a performance test once every five years, as is required in many Title V Permit renewals, will still accomplish the same assurance of compliance at a reduced cost to the regulated source.

A significant amount of testing will be required by sources to determine the compliance status with respect to the rule and to evaluate and select available control strategies. Capital projects to install necessary control equipment cannot proceed until the testing and evaluation is complete. Due to the high number of sources affected by the rule that have the same concerns, it is likely that availability of stack testing personnel and laboratory facilities to conduct tests will be limited, adding to the time required to complete this essential first step. As outlined below, annual compliance testing requiring multiple test runs for purposes of compliance will further reduce the availability of testing and laboratory resources.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 97

Comment: EPA has underestimated the cost of emissions testing necessary to comply with Boiler MACT. Typical industrial boilers combust a variety types of fuels. This practice is necessary for industry to maintain competitive fuel pricing. In the preamble to the rule, EPA cites, industry average costs per compliance test ranging from \$60,000 to \$90,000 per test. In many cases, however, sources may be required to perform 2 to 3 or even more tests to provide data on the range of fuels being combusted. These annual compliance testing costs of \$60,000 to \$270,000 are unreasonable and do not take into consideration the monetary impact associated with the identification and investigation of new fuel sources. In addition, testing annually requires an exorbitant amount of company resources to plan, schedule, and perform the required testing which have not been included in the above mentioned cost estimates.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Sarah Hedrick

Commenter Affiliation: Verso Paper Corp.

Document Control Number: EPA-HQ-OAR-2002-0058-3537-A2

Comment Excerpt Number: 1

Comment: The proposed rule will allow units that demonstrate compliance for a particular pollutant at a level at or below 75 percent of the emission limit for two consecutive years to forego stack testing for up to 37 months. Since most pollutant testing will be completed during worst case scenarios, this allowance will likely provide no relief of the performance test requirement’s costly burden. Also, because of the worst cast fuel mix and operating limit requirements, many multiples of stack testing scenarios will be required. The yearly stack testing campaign to meet the proposed rule requirements will range from \$40,000 to \$50,000 per boiler. This is an unreasonable cost. Verso believes stack testing be required once every 5 years.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Linda Miller

Commenter Affiliation: New Jersey Department of Environmental Protection (NJDEP)

Document Control Number: EPA-HQ-OAR-2002-0058-3664-A2

Comment Excerpt Number: 3

Comment: The proposed rules for oil--fired boilers require annual stack tests to determine compliance with the particulate matter, carbon monoxide (CO), hydrogen chloride (HCI), and mercury emission limits. This testing schedule is appropriate for heavy oil.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Robin Mills Ridgway
Commenter Affiliation: Purdue University
Document Control Number: EPA-HQ-OAR-2002-0058-3668-A2
Comment Excerpt Number: 18

Comment: In §63.1515(a), performance tests in the repropoed Boiler MACT are required annually. Purdue University enters into multiple year contracts for fuel supply with specific requirements for the fuel. Hence, fuel supplies do not vary frequently and annual stack testing is a waste of resources. Purdue asks that Boiler MACT testing, at the very least, be synchronized with Title V performance testing. In Purdue's case, this synchronization (biennial instead of annually) would save approximately \$18,000/year in testing costs.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Pat Dennis
Commenter Affiliation: Archer Daniels Midland Company
Document Control Number: EPA-HQ-OAR-2002-0058-3670-A2
Comment Excerpt Number: 6

Comment: EPA should modify the final emission testing requirements so that they are consistent with the 5 year Title V pennit review cycle. Annual compliance testing is extremely expensive and the benefits of conducting emission tests more frequently than every 5 years do not justify the costs. In addition, there is likely to be a shortage of testing and laboratory resources under the current emission testing schedule.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Pat Dennis
Commenter Affiliation: Archer Daniels Midland Company
Document Control Number: EPA-HQ-OAR-2002-0058-3670-A2
Comment Excerpt Number: 7

Comment: ADM appreciates the change in the frequency of performance testing from annually in the final rule to once every three years in the reconsideration rule. However, requiring a performance test once every five years, as is required in many Title V Permit renewals, will still accomplish the same assurance of compliance at a reduced cost to the regulated source.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Pat Dennis
Commenter Affiliation: Archer Daniels Midland Company
Document Control Number: EPA-HQ-OAR-2002-0058-3670-A2
Comment Excerpt Number: 8

Comment: The benefits of testing more frequently than every 5 years do not justify the costs. HAP emissions change only when operating parameters change (e.g., firing rate, maximum contaminant input limits for chloride and mercury, type of fuel, combustion efficiency, oxygen content, etc.) or when design changes occur. Absent these changes to an affected source, operating parameters established by implementation of Boiler MACT are more than sufficient to ensure that emissions will not significantly change over time.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Bill Lane

Commenter Affiliation: American Home Furnishings Alliance (AHFA)

Document Control Number: EPA-HQ-OAR-2002-0058-3676-A2

Comment Excerpt Number: 10

Comment: In the Reconsideration Proposed Rule, EPA has proposed annual performance testing requirements for all parameters. EPA has also proposed that the frequency can be reduced if the facility demonstrates compliance at 75% of the applicable emission standard. While AHFA supports reduced monitoring requirements for boilers that are in compliance, we urge EPA to establish a five-year performance testing frequency (after initial performance testing) for all parameters. Annual performance testing for industrial boilers would be far more stringent than testing requirements under other MACT standards. EPA has not provided a valid justification for why industrial boilers should be subject to more frequent performance testing and the related costs and disruption.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 99

Comment: Additional performance test timing flexibility should be provided.

Proposed §63.7515(a) requires that annual performance tests be performed within 13 months of the previous test. This is a reasonable interval if a facility is dealing with one stack test, but can be a problem if the facility has to perform many stack tests (i.e., has many BPH requiring testing). Burdens for both the facility and inspectors can be reduced if stack tests can be adjusted to space out the testing over a year and to allow test time to be adjusted so that operation at stack test conditions can be matched to operating needs. For instance, if the annual test is due when a process heater must operate at low rates because the process is at low rates, there needs to be a mechanism to allow several months adjustment. To that end we request that the testing interval be revised to annual and that annual be specified as once per calendar year with at least 120 days between tests. EPA is generally adopting such requirements in EPA's new Uniform Standards⁴⁹

and has used this approach successfully for many years under the existing HON (part 63 subparts F, G, and H) and the Generic NESHAP (part 63 subpart YY).

[Footnote 49: Proposed §65.280(b) of the Uniform Standard General Provisions specifies: “(b) You may comply with such periodic requirements by completing the required task any time within the standard calendar period, provided there is a reasonable interval between completion of two instances of the same task. Reasonable intervals are described in paragraphs (b)(1) through (5) of this section. ... (5) Tasks that you are required to complete annually must be separated by at least 120 calendar days.”]

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 101

Comment: It is a massive undertaking for non-continental refineries to perform stack tests every year, given that stack testers must be brought in and samples often must be shipped to far off mainland laboratories. One solution would be to allow non-continental sources to skip stack testing if they are willing to continue to meet the continuous compliance parameter established previously. An oxygen level established in an initial performance test should remain a good indicator of good combustion (low CO and particulates) indefinitely. Thus, we request that new performance tests for the non-continental liquids subcategory only be required every five years.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

110B. Operating Load Limits During Testing [DENIED PETITIONER ISSUE]

Commenter Name: John S Williams

Commenter Affiliation: Maine Pulp & Paper Association (MPPA)

Document Control Number: EPA-HQ-OAR-2002-0058-3466-A1

Comment Excerpt Number: 8

Comment: EPA should not limit boilers to 110% of the operating load achieved during the last performance test.

It appears that, under the Boiler MACT rule, mills must conduct a compliance test for CO and, thereafter, meet an oxygen limit which is the lowest oxygen level recorded during the three one-hour test runs for CO. The rule requires that a boiler must then be operated at not more than 110% of the operating load achieved during the performance test. The highest operating load in a multi fuel boiler often does not correspond with the lowest oxygen condition. This approach is difficult if not impossible to meet in a multifuel boiler, such as those in use at most of Maine's

mills. If wet fuels happen to be burned during the stack test (EPA requires 60 day notice prior to testing and the weather cannot be predicted) higher levels of oxygen are required and the resulting increase will affect the ability to comply with the CO limit. When burning biomass, stack oxygen concentrations will be much higher than when firing fuel oil.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: John S Williams

Commenter Affiliation: Maine Pulp & Paper Association (MPPA)

Document Control Number: EPA-HQ-OAR-2002-0058-3466-A1

Comment Excerpt Number: 9

Comment: EPA's stack test compliance approach appears based on the incorrect premise that CO emissions from a biomass boiler exhibit low variability. It is unreasonable to establish a CO emission limit based on a single hourly emission value. Additionally, the rule imposes limitations on boiler steam output operation to that achieved during the CO testing. Paper mill boilers are operated at variable loads based on the process steam demands. It will be impractical to operate at maximum loads during every stack test. Limiting boiler capacity to 110% of the value achieved during a performance test undermines the economic survival of a mill.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: John S Williams

Commenter Affiliation: Maine Pulp & Paper Association (MPPA)

Document Control Number: EPA-HQ-OAR-2002-0058-3466-A1

Comment Excerpt Number: 10

Comment: The rule appears to require multiple stack test runs for each parameter to demonstrate compliance with each emission limit (two or more tests for CO, two tests for HCL, two tests for Hg, one or more tests for PM ... these tests will not run concurrently). The worst case fuel mix for CO is likely not the same fuel mix needed to establish minimum O₂ parameter or the boiler steaming that is needed for normal operation. If performance testing needs to be at the worst case mix for a pollutant, that worst case fuel mix cannot then be tied to a steaming rate limit of 110% achieved during the performance test. (Table 7 in the proposed rule limits the operation capacity to 110% for all pollutants tested).

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Claudia M. O'Brien, Latham & Watkins LLP

Commenter Affiliation: JELD-WEN, inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3485-A1

Comment Excerpt Number: 7

Comment: Although JELD-WEN supports these proposed changes, JELD-WEN believes that EPA did not go far enough in recognizing the importance of operational variability. Specifically, EPA did not account for such variability for sources that demonstrate compliance through performance testing. In its final rule, EPA required sources demonstrating compliance through performance testing to limit their operating load to no greater than 110 percent of the operating load established during the performance test. However, this operating limit raises serious technical problems for facilities due to seasonal variability—the same variability EPA recognized in its proposed revision for sources using parametric monitoring and continuous compliance with operating limits.

As JELD-WEN explained in its petition for reconsideration, during compliance testing, a facility has to show minimum and maximum operational conditions occurring during testing. During the winter, when steam demand is greater (due to greater ambient losses and the addition of building heat), a unit might test, for example, at 30 MMBtu/hr of heat input; the unit would not be permitted to exceed 33 MMBtu/hr during the normal course of operations regardless of season. However, if that same facility tested during the summer when there is the lowest load requirement, it may test at 24 MMBtu/hr and then would not be permitted to exceed 26.4 MMBtu/hr during all seasons.²⁴ Thus, under the Boiler MACT rule the facility would not be able to meet the steam demand in the winter if it conducted performance testing during the summer. While EPA may suggest that such facilities conduct performance testing in the winter to address this consequence, winter testing is simply not feasible in many parts of the country. Testing in winter months in icy conditions and high winds raises serious safety concerns.

JELD-WEN urges EPA to remove this limitation, particularly for those boilers or process heaters that are less than 100 MMBtu/hr. JELD-WEN recognizes the importance of using performance tests to set the operational parameters that ensure compliance on a continuous basis, but submits that such a requirement is unnecessary with respect to operating load. That is, compliance with Boiler MACT is established on a lb/mmBtu basis, not a total tonnage basis, such that a mandated maximum operating load is not necessary to ensure compliance with a tonnage limit. Further, as EPA is well aware, control devices typically perform better at higher loads, such that a performance test occurring at lower loads is likely to overstate emissions at higher loads. As such, an upper limitation on operating load is not necessary to ensure continuous compliance with Boiler MACT's emission rate limitations. Moreover, a 10 percent change in heat output for a small boiler (40 MMBtu/hr for example) would result in a change within the error margin of the testing itself.

Just as EPA proposed a revision of averaging times to address seasonal variability, EPA should likewise eliminate the requirement to limit the operating load to no greater than 110 percent of the operating load established during the performance test. At a minimum, for boilers less than 100 mmBtu/hr, EPA should modify the requirement to allow operating loads of at least 130 percent of the operating load established during the performance test.²⁵

[Footnote 24: Many companies record the boiler's operating load by recording the steam produced by the boiler. When operating in the summer months, a typical steam demand can be 533,000 lbs steam. This steam demand is for the nonnal operation of the facility. However, in the winter months, the steam demand can be approximately 706,000 lbs-steam due to ambient losses, the addition of building heat, and the normal operation of the facility. This results in a 25%

change in steam demand between the two extreme seasonal temperatures, which exceeds the rule's limit of 10%.]

[Footnote 25: Furthermore, the regulation requires that the Method 19 F-factor be used to determine the pollutant emission rate. This method in itself can result in a 5% error in the reported value. Depending on the pollutant being tested and the test method used, the internal QA/QC of the test method can result in an error of up to 30%.]

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: David A. Buff, Golder Associates Inc.

Commenter Affiliation: Florida Sugar Industry (FSI)

Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1

Comment Excerpt Number: 39

Comment: As discussed in more detail elsewhere in these comments, for units that already have CO CEMS for reasons unrelated to the Boiler MACT Rule, compliance with the Boiler MACT Rule's stack-test-based CO emissions limitations would be difficult to maintain. Stack tests are required to be run under representative operating conditions, typically defined as operating at or near full load consistently for the duration of the stack test. In sharp contrast, CEMS take emissions data on a near-continuous basis, which means CEMS emissions measurements reflect significant variability in emissions (for example, due to load swings and low load conditions) that was not measured during the stack tests used to set the CO standard. This problem is not overcome by statistical manipulation of the CO standard, such as accounting for variability using the UPL method, because such statistical methods unrealistically extrapolate only from the variability measured during stack tests and the variability between stack tests. In other words, this is a classic "apples and oranges" situation where emissions data from CO CEMS are incompatible with emissions data from stack tests used to set the CO standard.

One way for EPA to resolve this incompatibility is to determine that emissions data from CO CEMS are not credible evidence for purposes of assessing compliance with the Boiler MACT Rule's stack-test-based CO emissions limitations. As EPA explained in the "credible evidence rule," data and information derived from methods other than the specified reference test method (so-called "non-reference test data") are relevant to showing compliance only to the degree that "the appropriate reference test would have shown a violation." 62 F.R. 8314, 8323 (Feb. 24, 1997). Because the Boiler MACT Rule's CO standards are based on stack test data, and because the stack tests on which the standards are based were required to be conducted during representative operating conditions (*i.e.*, consistently operating at or near full load), then by definition CO CEMS data taken during periods of operation that do not reflect "representative operating conditions" are not data that are relevant to showing compliance with the standards.

In other words, the stack test data on which the standards are based reflect operation during a narrow, limited, and optimum set of conditions. Conversely, CO CEMS data that are taken during periods of operation that do not reflect those limited conditions are not relevant to determining whether an affected source is in compliance with the standard.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 123

Comment: Performance testing should be carried out at representative conditions and the requirement to establish a BPH operational load operating limit in Table 4 Item 8 and Table 7 Item 5 should be deleted.

Proposed §63.7520(a), following §63.7(e) of the part 63 General Provisions, states “You shall conduct all performance tests under such conditions as the Administrator specifies to you based on representative performance of the affected source for the period being tested.” Table 4 Item 8 and Table 7 Item 5 requires that a BPH demonstrating compliance using a performance test must not be operated at greater than 110% of the load at which the boiler or process heater was tested during the previous performance test. This often requires that all such performance tests be run at greater than or equal to 90% of maximum load, thereby overriding §63.7520(a) and §63.7(e), because otherwise the boiler or process heater would be restricted from raising rates for even short periods. In many cases operating at such a high percent of load presents problems since boiler and process heat operating rate must match the operating rate of the process for which they provide heat or steam. Moving around entire processes just to perform performance tests is costly, wasteful and has not been considered in developing this rule’s costs or burdens. Furthermore, operating at such high loads is not generally necessary to assure compliance, since most boilers and process heaters are likely to operate well below the emission limits where performance testing will be used for demonstrating compliance. We suggest an operating limit is not needed, since if a boiler or process heater operates significantly above the test point, it would be required to test at a higher load on the next test occasion by the regulating authority reviewing the planned performance test conditions.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Heather Parent

Commenter Affiliation: Maine Department of Environmental Protection

Document Control Number: EPA-HQ-OAR-2002-0058-3691-A2

Comment Excerpt Number: 9

Comment: Maine DEP strongly objects to the inclusion of a steam load limit of 110% of the average steam load attained during the last performance test. The rule requires testing using a worst case mix of fuels. However, a worst case fuel mix will not allow biomass and multi-fuel boilers to operate at high steam loads. The rule would effectively prohibit many boilers from operating at even normal steam loads.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

110C01. Fuel Sampling Procedures [DENIED PETITIONER ISSUE]

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 117

Comment: Requiring daily checks of pressure taps for blockage is not standard practice and not justified in services where such blockage is not likely. Proposed §63.7525(f)(4) should be deleted or, at the most, only apply to pressure taps where there is a history of pressure measurement problems due to tap blockage.

Proposed §63.7525(f)(4) requires daily checks of pressure taps for blockage. This extremely burdensome requirement should be deleted, since pressure tap blockage is highly unusual, particularly around BPH and their controls. If EPA knows of a specific situation where such blockage is likely (and not just possible, in a theoretical sense) it should apply this requirement to just that specific situation. In addition to imposing a large wasteful burden⁵⁰, such checks typically require releases to the atmosphere and exposure of personnel and thus unnecessary checks are to be avoided.

[Footnote 50: For instance, such a check might require 30 minutes per day of technician time per instrument. This cost was not considered in the cost and burden estimates for this rulemaking. Similarly, EPA did not account for the emissions impacts of this requirement or the cost of the additional facilities that would be required.]

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

110C02. Reduce Fuel Analysis Burden [DENIED PETITIONER ISSUE]

Commenter Name: Michael D. Wendorf

Commenter Affiliation: FMC Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3453-A1

Comment Excerpt Number: 2

Comment: §63.7530(b) describes the method by which maximum fuel pollutant levels are established for use as operating limits to demonstrate continuous compliance with the alternative TSM emission limit. The fuel operating limit remains in effect until such time as the source conducts another stack emission test and a new fuel TSM limit is established.

This methodology establishes TSM limits that are overly proscriptive, and in fact results in stack emission limits that are lower than the rule dictates. It is nearly impossible to procure a shipment

of fuel from a supplier that would contain the highest TSM concentration anticipated in the future for use during a particular emission stack test.

Consequently, a boiler is constrained to burn fuel that is less than or equal to the prevailing fuel TSM operating limit. The only means to develop a reasonable fuel operating limit would be to continually repeat emission stack testing each time a coal shipment indicates higher fuel TSM levels than the existing operating limit. Unfortunately, analytical results for fuel TSM on any specific coal shipment arrive after the coal is burned; most coal reclaim systems are not designed to segregate an individual coal shipment without significant disruption to the normal reclaim process.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Michael D. Wendorf

Commenter Affiliation: FMC Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3453-A1

Comment Excerpt Number: 3

Comment: The problem of repetitive stack testing is acknowledged by EPA in §63.7520(c), albeit with some understatement:

We request EPA to consider allowing the operator to adjust the fuel TSM operating limit based on the results of the stack emission test. Example: an existing coal-fired PC boiler completes Method 29 stack emission testing and demonstrates a TSM emission rate of $4.5E-05$ lb/MMBtu, or 76% of the TSM emission limit. This percentage is then applied to the corresponding fuel TSM value, TSM_{90i} , as calculated from §63.7520(c)(5) Eq. 13:

$$TSM_{oL} = 0.0000655 + (4.5E-05 + 5.9E-05) = 0.0000862 \text{ lb/MMBtu}$$

where:

TSM_{oL} = adjusted TSM fuel operating limit, lb/MMBtu
 $0.000655 = TSM_{90i}$ from fuel analysis during Method 29 stack test

$4.5E-05$ = result of Method 29 stack test, lb/MMBtu

$5.9E-05$ = proposed TSM limit, coal-fired PC boiler, lb/MMBtu

The adjustment would reflect the level of TSM that could have been in the fuel at the time of the stack test that would have still resulted in meeting the TSM emission limit at the stack exit. This assumes a direct relationship between fuel and stack TSM emissions, upon which the rule already relies. This same adjustment mechanism could be applied for HCl and Hg, as well.

FMC requests EPA to consider this approach, as it provides a logical means of establishing an appropriate fuel operating limit reflective of the stack emission rate, all without onerous and expensive retesting. It eliminates a stack emission limit being directly imposed upon the boiler that is lower than specified by the rule simply due to fuel not containing the maximum HAP pollutant concentration at the time of the stack test.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Sarah E. Amick

Commenter Affiliation: Rubber Manufacturers Association (RMA)

Document Control Number: EPA-HQ-OAR-2002-0058-3503-A1

Comment Excerpt Number: 16

Comment: Section 63.7515(f) requires monthly fuel analysis if a facility is complying with numeric emission limits using fuel analysis rather than stack testing:

“If you demonstrate compliance with the mercury, hydrogen chloride, or total selected metals based on fuel analysis, you must conduct a monthly fuel analysis according to § 63.7521 for each type of fuel burned that is subject to an emission limit in Table 1 or 2 to this subpart.”

RMA member facilities may burn a percentage of light or heavy fuel oil subject to numeric emission standards only part of the year, and burn natural gas at other times. These facilities should not have to conduct monthly fuel analysis if they have not received additional fuel shipments since the last fuel analysis was performed.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Chris M. Hobson

Commenter Affiliation: Southern Company

Document Control Number: EPA-HQ-OAR-2002-0058-3520-A1

Comment Excerpt Number: 11

Comment: The requirement to set a maximum fuel input level even if a source chooses to demonstrate compliance through performance testing gives no regard to the compliance margin the source may have achieved during the test. In the reconsideration notice, EPA states that "it is impracticable to replicate, during performance testing, all of the varying fuel conditions necessary for calibrating the monitor" specifically for biomass units.⁶ Considering the natural variability in the fuel and the fact that biomass fuel is generally stored for two weeks or less at a time, it is similarly impracticable to ensure that the batch of biomass the facility receives and burns during the performance test represents the maximum fuel input level.

[Footnote]

(6) 76 Fed. Reg. at 80609

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 111

Comment: The general compliance plan outlined in the proposed rule is that sources (1) demonstrate compliance with applicable emissions limitations and work practice standards through the conduct of an initial performance test; (2) establish operating limits based upon results of the performance test; (3) conduct monitoring and maintain records demonstrating that the source is operated on a continuous basis consistent with the operating limits established during the performance test; and (4) periodically repeat the performance testing. Operating parameter limits based on fuel input analysis (e.g., HCl and Hg), are established using Equations 7 and 8 in §63.7530. Then, on a continuing basis, facilities are required to keep extensive records of all fuels burned in each boiler or process heater during each compliance reporting period. If a source changes fuels, it must re-calculate its fuel input values using applicable equation 7 or 8. If the re-calculated value exceeds the existing limit, the source is required to conduct a new performance test and establish new operating limits.

While this compliance approach may be easy to manage for some sources, especially ones with very stable fuel supply and usage, it may be very cumbersome and burdensome for other sources with variable fuel suppliers and fuel mixes. This approach involves a great deal of recordkeeping and potentially subjects the source to frequent testing requirements if fuel content varies, regardless of the margin of compliance shown during the initial performance test. Under the proposed rule, even if a unit is operating at 50 percent of the applicable emission limit, the facility would be required to re-test if the fuel chloride input increases 1 percent over the level achieved during the initial performance test.

A more appropriate approach is to allow the source to set operating parameters at levels that generate emissions at the emission limits established in the rule. This is the only approach which meets the requirements of the Act, since it is the only approach that does not impose a beyond the floor limit which has not been justified per the requirements of 112(d). Under this approach, the source would simply conduct the performance test using its normal fuel mix, determine operating conditions that show compliance and then adjust those conditions, using engineering calculations to assure it would meet the emissions standards established in Table 1 or 2. If the initial performance test shows emissions at 50 percent of the standard at a particular mercury or chloride fuel input, the fuel input limits should be set at a level higher than the performance test values, taking into account control device operating parameters as appropriate. This approach would be environmentally beneficial and would greatly reduce burdens. It is the only practical way to establish fuel input operating limits.

Compliance could also be demonstrated through the use of fuel purchase specifications. Sources would determine from the performance test a maximum fuel pollutant concentration at which the emissions limitations are achieved. For instance, the performance test may demonstrate that fuels containing chlorine in concentrations less than x Ib Cl/MMBtu allow the source to comply with emissions limitations. A facility should be allowed to extrapolate an allowable fuel input based on a comparison of performance test conditions to the applicable emission limit. The source would then set a fuel specification of x Ib Cl/MMBtu and would be allowed to burn any fuel of the same general type (e.g., solid, liquid, or gas) as long as it met this specification. Sources could require that the fuel supplier provide periodic certification that the fuel meets the specification, based on analysis, or could establish an internal sampling and analysis program for

that purpose. In any case, where common fuels are utilized in more than one unit, common fuel quality data would be maintained and considered applicable to all such units. Continuous compliance could also be demonstrated through ongoing fuel analysis.

As an example, sources would (1) establish a fuel input limit (e.g., lb Cl/MMBtu) based on the compliance test as described in the proposal (with an allowance for extrapolation); (2) periodically sample and analyze each fuel for constituent concentration and heating value according to a specified sampling and analysis plan; (3) monitor the daily usage of each fuel; (4) calculate the average total daily constituent input (lb/MMBtu) accounting for all fuels fed; and (5) demonstrate that the average daily constituent input rate averaged over each month of operation does not exceed the operating limit. This option would afford the source the opportunity to vary fuel mixes, while still insuring that protective operating limits are met.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 116

Comment: Section 63.7515(f) requires monthly fuel analysis if a facility is complying with numeric emission limits using fuel analysis rather than stack testing:

"If you demonstrate compliance with the mercury, hydrogen chloride, or total selected metals based on fuel analysis, you must conduct a monthly fuel analysis according to § 63.7521 for each type of fuel burned that is subject to an emission limit in Table 1 or 2 to this subpart."

Some facilities may burn certain fuels subject to numeric emission standards only part of the year, and burn natural gas at other times. These facilities should not have to conduct monthly fuel analysis if they have not received additional fuel shipments since the last fuel analysis was performed.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Sarah Hedrick

Commenter Affiliation: Verso Paper Corp.

Document Control Number: EPA-HQ-OAR-2002-0058-3537-A2

Comment Excerpt Number: 4

Comment: The monthly fuel sampling requirement is excessively burdensome. While the proposed rule does provide some relief after the first year (in that facilities can request a reduced sampling frequency), monthly sampling during the first year is still too burdensome. Annual sampling is sufficient to demonstrate compliance. As written, the rule is excessively labor-intensive and costly for facilities.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Bill Lane

Commenter Affiliation: American Home Furnishings Alliance (AHFA)

Document Control Number: EPA-HQ-OAR-2002-0058-3676-A2

Comment Excerpt Number: 11

Comment: AHFA is concerned with the proposed requirement for establishing operating parameters based on initial performance tests and fuel analysis testing for mercury, hydrogen chloride (HCl), and total selected metals (TSM). Under the Proposed Reconsideration Rule, a facility that retests an existing fuel resulting in a higher pollutant concentration due to natural variability of mercury, TSM, or HCl in the biomass fuel supply is required to undertake additional performance testing at considerable cost, even though the additional source testing provides no environmental benefit. The relationship between metal, mercury, and chlorine in a fuel and in an air exhaust stream can be clearly documented, negating the need for additional source testing due to a minor increase in a laboratory result. Instead of a requirement for additional source testing, we urge the EPA to allow establishment of fuel concentrations as a parametric indication of stack emissions. The parametric monitoring limits would be established by concurrent fuel and source testing. If compliance fuels testing calculations exceed a defined threshold (e.g., 90% of the applicable emissions limitation), then source testing would be required at that time to demonstrate continued compliance. Rather than requiring performance testing every time a lab result shows any increase in a regulated pollutant, the Boiler MACT rule should allow affected sources to adjust their fuel mix and demonstrate compliance based on engineering calculations and the fuel analysis.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Bill Lane

Commenter Affiliation: American Home Furnishings Alliance (AHFA)

Document Control Number: EPA-HQ-OAR-2002-0058-3676-A2

Comment Excerpt Number: 12

Comment: AHFA is concerned that the rule requires monthly fuel testing for facilities using the fuel analysis option, even if the source or type of fuel does not change. Monthly testing of fuel would also be required if fuel is delivered less frequently than monthly. AHFA believes the fuel testing should only be required when the source or type of fuel changes, consistent with previous Boiler MACT proposals.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 102

Comment: We believe the same burden reduction opportunity exists for the fuel analyses requirements and this reduced testing frequency should be extended to fuels analysis without requiring approval. Proposed §63.7515(f) states:

(f) If you demonstrate compliance with the mercury, hydrogen chloride, or total selected metals based on fuel analysis, you must conduct a monthly fuel analysis according to § 63.7521 for each type of fuel burned that is subject to an emission limit in Table 1 or 2 to this subpart. If you burn a new type of fuel, you must conduct a fuel analysis before burning the new type of fuel in your boiler or process heater. You must still meet all applicable continuous compliance requirements in § 63.7540. If 12 consecutive monthly fuel analyses demonstrate compliance, you may request decreased fuel analysis frequency by applying to the EPA Administrator for approval of alternative monitoring under § 63.8(f).

Using §63.8(f) to obtain approval of a decreased analysis frequency is unworkable and reduced monitoring should be directly implemented in this paragraph. Under the proposal, §63.8(f) alternative approval authority is reserved from delegation and thus would be implemented by EPA. EPA has repeatedly demonstrated a clear inability to consider alternative requests in a timely manner, in some cases never responding to such requests. Thus, using §63.8(f) is not a realistic way of reducing burdens in this kind of low risk situation. After 12 months of data have been collected on a fuel there is little risk of change unless the fuel is purposely switched. In that case, under the proposal, any change in fuel would require a new analysis and under §63.7540 a notice of the change. Thus, we recommend, in line with the stack testing burden reduction proposal, that proposed §63.7515(f) allow, without further approval, a reduction to quarterly fuel testing after the 12 months if the mercury, hydrogen chloride or TSM content was less than 75% of the applicable limit for the previous 12 months.

We suggest the following revision to §63.7515(f).

(f) If you demonstrate compliance with the mercury, hydrogen chloride, or total selected metals based on fuel analysis, you must conduct a monthly fuel analysis according to § 63.7521 for each type of fuel burned that is subject to an emission limit in Table 1 or 2 to this subpart. If you burn a new type of fuel, you must conduct a fuel analysis before burning the new type of fuel in your boiler or process heater. You must still meet all applicable continuous compliance requirements in § 63.7540. If 12 consecutive monthly fuel **analyses** demonstrate 75% or less of the compliance level, you may decrease the fuel analysis frequency to quarterly for that specie. If any quarterly sample exceeds 75% of the compliance level or you begin burning a new type of fuel, you must return to monthly monitoring for that specie, until 12 months of fuel **analyses** again are less than 75 % of the compliance level. If 12 consecutive monthly fuel **analyses** demonstrate compliance, you may request decreased fuel analysis frequency by applying to the EPA Administrator for approval of alternative monitoring under §63.8(f).

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Douglas A. McWilliams
Commenter Affiliation: American Municipal Power
Document Control Number: EPA-HQ-OAR-2002-0058-3685-A2
Comment Excerpt Number: 35

Comment: AMP finds EPA's imposition of operating limits based on performance tests to be an impermissible beyond-the-floor requirement that was adopted without considering costs and other factors required by the Clean Air Act. Operating parameters should be indicators that trigger corrective actions to ensure proper control device performance; they should not be enforceable limits that tie an operator to the performance level during a test regardless how far below the MACT floor standard the unit tested.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Samuel H. Bruntz
Commenter Affiliation: Alcoa Power Generating, Inc.
Document Control Number: EPA-HQ-OAR-2002-0058-3755-A1
Comment Excerpt Number: 8

Comment: Alcoa questions the Liquid Flow and Pressure Drop CMS Requirements.

Alcoa~ Warrick may elect not to equip its pulverized coal boilers with mercury CEMS or Appendix K absorption tubes. In that case, the scrubber liquid flow, scrubber pressure drop, and electrostatic precipitator monitoring requirements of 63.7525 (d) would be applicable.

In its current Title V permit, Alcoa- Warrick bases liquid input on the supplied pump curves, which indicate flow as a function of pump motor amperage. Alcoa- Warrick has found this method to be adequate for the intended purpose~ i.e. verification that the scrubber is operating in a similar manner to that measured during the most recent performance test.

63.7525 (e) (1) through (3) does not take into account that there could be issues with spray patterns as nozzles wear over time. Liquid flow measurements would not take that effect into account, and would thus not be an accurate indicator of pollutant removal.

Alcoa- Warrick estimates that \$750,000 would be needed to add the liquid flow measurement and associated data acquisition systems needed to meet 63.7 525 (d). Such an expenditure is not justified, given that highly precise liquid flow measurement may not be a highly accurate indicator of scrubber performance.

Alcoa- Warrick agrees with the concept outlined in the July 29, 2011 comments letter provided with respect *to* the proposed MATS regulatory action by Thomas Easterly, Commissioner of the Indiana Department of Environmental Management, i.e. "Indiana asks that States be allowed maximum flexibility to develop alternate compliance plans that afford the regulated community opportunity to assure timely compliance, while also assuring that consumers are not adversely affected. "

In concert with the sentiment expressed by Commissioner Easterly, Alcoa- Warrick recommends that States be provided the flexibility to approve liquid flow monitoring and other portions of the required CPMS monitoring plan. To that end Alcoa- Warrick recommends that 63.7525 (d) be amended as follows:

(d) If you have an operating limit that requires the use of a flow monitoring system, you must develop a flow monitoring plan in consultation with your State regulatory agency. The plan must be approved by the agency in advance of the initial compliance demonstration.

63.7525 (e) would then be deleted.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: M.L. Steele

Commenter Affiliation: CraftMaster Manufacturing, Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3814-A1

Comment Excerpt Number: 16

Comment: Demonstration of HCl and Hg compliance by monthly fuel analyses, §63.7530(c) and §63.7521. For CraftMaster's biomass fuels it will not be possible to use fuel analyses to demonstrate compliance with the proposed HCl limit using the method outlined in §63.7530, equations 10 and 11 *even when the results of all fuel analyses are below the method detection limit*. The ASTM method for Cl has a detection limit for CraftMaster's biomass fuels of 200 mg/kg. This is due to the ASTM procedure available (04208-02) and the relatively low dry bulk density of the biomass fuels. The relatively low higher heating value of the biomass is also a contributing factor. Then, even if all fuel analyses results are not detected and values are considered to be the method detection limit, the Lbs HCl per MMBtu calculated using equation 11 are above the proposed limit. We believe this would be the case for other biomass and biomass-based fuels as well. To address this issue we request that the proposed limit be raised and/ or the averaging period for the compliance demonstration be increased from monthly to semi-annually. This would increase the number of samples considered and reduce the 90% confidence value from 1.89 standard deviations (δ 's) to 1.33 δ 's if three samples per month are analyzed.

We believe similar changes would be appropriate for mercury as well.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: M.L. Steele

Commenter Affiliation: CraftMaster Manufacturing, Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3814-A1

Comment Excerpt Number: 18

Comment: Under §63.7515(f) one must petition the Administrator for a lesser frequency of fuel analyses if results show compliance for twelve consecutive months. CraftMaster requests that this be automatic, as in the case of stack testing in §63.7515(b).

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

111B02. Use Consistent Averaging Times for Initial and Continuous Compliance [DENIED PETITIONER ISSUE]

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 26

Comment: EPA proposes to allow sources to demonstrate compliance with emissions limits by averaging emissions data over a longer time period. Specifically, EPA proposes to permit compliance determinations to be made on the basis of a 30-day rolling average. Although rolling averages are better than block averages, which allow polluters to comply based on the entirely fortuitous circumstance of a new block period beginning between elevated test runs, EPA has failed to adjust the applicable emissions limits to account for a 30-day averaging period. As a result, EPA’s proposed standards will not require units to control emissions to the level of the best performers. This is true in at least two respects. First, EPA calculated the emissions limits based on the highest one-hour emissions tests of the best sources (adjusting upwards for assumed variability). Thus, the numerical limits reflect peak emissions, not average emissions. By definition, an average emission level is lower than an emissions peak. Yet EPA now proposes to allow all sources to emit *on average* at the same level that the best performers emit *at peak times*. Second, EPA selected the best performers on the basis of one-hour test runs, not 30-day averages. Units not selected as the best performers may actually have yielded lower 30-day average emissions limits than those selected. To comply with the requirement to set the MACT floor based on the best performers, EPA must use the same methodology both in selecting the best performers and then in calculating the limits. For both of these reasons, EPA’s failure to adjust its emissions limits in accordance with the switch to 30-day average compliance determinations is contrary to section 112(d)(3) and arbitrary.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Mary Sullivan Douglas

Commenter Affiliation: National Association of Clean Air Agencies (NACAA)

Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1

Comment Excerpt Number: 21

Comment: EPA observes that standards are to be complied with “at all times,” but this is a truism that is not particularly helpful.¹⁸ What are helpful are the provisions in the rules that set out the conditions under which compliance will be determined. In years past, facilities were to be

tested under “reasonable worst case conditions.” Today, that standard has been reduced to “representative” conditions – a phrase that suggests that a compliance margin based on a 99th percentile projection¹⁹ of possible emissions may be too large and that industry projections of severe test conditions may be overstated. Moreover, the structure of the compliance obligations itself suggests that the 99th percentile may be too stringent. The following factors, among others set out in the proposed rules, bear on a determination of the appropriate compliance margin:

1. For sources that intend to comply with mercury and hydrogen chloride (“HCl”) fuel sampling, the rules require that a source conduct a stack test and demonstrate compliance using 90th percentile worst-case fuel (employing Student’s t-test to determine that percentile);
2. For other purposes (e.g., PM and CO compliance), the source may select a “representative” operating condition (suggesting that neither a 90th percentile nor a 99th percentile worst-case test is required for these pollutants);
3. A source whose emissions during a test are less than 75 percent of the applicable limit is entitled to a reduced frequency of stack testing (suggesting that EPA does not really believe that replicate testing of sources will vary by more than 33 percent);
4. Parametric operating limits may not generally be less effective than demonstrated during the stack test (a useful provision, but also one that suggests that EPA believes that in-use emissions variability is zero);
5. Many of the applicable standards and other requirements contain exclusions from full compliance at all times (e.g., six-minute exclusion under opacity requirements, 5-percent exclusion for bag leak detection systems);
6. Power (voltage or amperage) to electrostatic precipitators (“ESPs”) may not fall to less than 90 percent of that employed during a stack test²⁰ (for which we can think of no justification); and
7. Parametric limits are allowed to be based on the lowest (least effective) hourly parameters of the three runs of the compliance test. On its face this will not lead to compliance since it will be less than the average flow rate during the test. Moreover, such parametric limits do not provide any allowance for the variations employed in setting the standard. EPA should provide that the operating parameters be set at the levels employed during the test run that yielded the lowest emission rate, plus some additional margin to account for in-use variability.

[Footnotes]

(18) EPA also asserts that the failure of a compliance test is not a violation of a standard until and unless some governmental authority agrees. We understand the reference in the context of the annual certification of compliance (where EPA does not intend sources to have to “confess” to a violation of law), but not otherwise.

(19) We understand that a 99th percentile UPL is not precisely the same as a 99th percentile worst-case condition, but the differences are extremely subtle.

(20) If power to the ESP falls below that employed during the test, PM control efficiency would be reduced. The amount of this reduction is presumably unit-specific and so we can think of no justification for this provision.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

111B03. Deviation Definition [DENIED PETITIONER ISSUE]

Commenter Name: Lee Zeugin and Lauren Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1

Comment Excerpt Number: 30

Comment: The 2011 final rule is inconsistent in its treatment of periods during which a monitoring system is “out-of-control,” and does not adequately address periods of monitoring system maintenance. Provisions specific to O₂ CEMS and continuous opacity monitoring systems (“COMS”) require sources to identify any period during which the monitoring system is out-of-control as a deviation from the requirement to monitor. 40 C.F.R. §§ 63.7525(a)(6) and (c)(6). Although the rule excludes “required” monitoring system quality assurance and control activities from required monitoring system operation and deviation reporting, maintenance is not specifically excluded. *Id.* §§ 63.7535(a), 63.7535(d).

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Lee Zeugin and Lauren Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1

Comment Excerpt Number: 31

Comment: In comments on the 2010 proposed rule, UARG objected to the provisions addressing out-of-control periods for O₂ CEMS and COMS as unreasonable and inconsistent with the general provisions,¹⁵ and asked EPA to revise § 63.7535(b) to exempt out-of-control periods from the monitoring requirement. UARG also asked EPA to specifically exclude maintenance periods from the requirement for operation of monitoring systems. EPA-HQ-OAR-2002-0058-2880.1 at 55-58. In response, EPA revised § 63.7535(b) to exclude out-of-control periods from the monitoring requirement, and included such periods in a list of monitoring system events that did *not* constitute a deviation in a new subsection (d). 40 C.F.R. § 63.7535(d). However, EPA did not revise § 63.7525 to remove the provisions specific to O₂ CEMS and COMS. EPA also made no changes with respect to periods of monitoring system maintenance. Because EPA did not fully address or respond to UARG’s comments, UARG included the issue in its reconsideration petition. EPA-HQ-OAR-2002-0058-3324 at 18-19.

[Footnote]

(15) Section 63.8(c) specifically includes “out-of-control” periods as one of the exceptions to continuous operation of a monitoring system.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

111C01. Pressure Monitoring Taps [DENIED PETITIONER ISSUE]

Commenter Name: Samuel H. Bruntz

Commenter Affiliation: Alcoa Power Generating, Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3755-A1

Comment Excerpt Number: 9

Comment: Proposed regulation 63.7525 (t) is overly prescriptive. Industrial boiler operators may have experience that pressure drop sensors may provide reliable output at a less frequent cleaning frequency than daily. Alternatively, systems equipped with an auto purge system would not require the daily operator interaction of manually cleaning the sensors. This parameter is another candidate for negotiation between the State regulatory agency and EGU owner in the required CPMS monitoring plan. Accordingly, APGI recommends that 63.7525 (f) be amended as follows;

If you have an operating limit that requires the use of a pressure monitoring system, you must develop a pressure monitoring plan in consultation with your State regulatory agency. The plan must be approved by the agency in advance of the initial compliance demonstration. The plan must include the recommended accuracy, and include a recommended maintenance interval for adequate sensor cleaning if an auto purge system has not been installed."

63.7525 (f) would then be deleted.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

111C02. Revise Max/Min Operating Parameter Language [DENIED PETITIONER ISSUE]

Commenter Name: Lee Zeugin and Lauren Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1

Comment Excerpt Number: 34

Comment: EPA’s proposed operating parameters are not sufficiently connected to emissions to be enforceable limits. UARG objects to EPA’s proposal to use the control device parameter levels measured during performance testing as enforceable operating limits. Establishment of such limits reduces operational flexibility, deprives sources of the use of any control device margin, and allows enforcement for events beyond the owner/operator’s control.

EPA's current proposal is based on the faulty assumptions that the values of the parameters identified by EPA have a direct relationship to the level of emissions, and that exceedances of those limits may indicate an exceedance of the emission limit as well. To the extent possible, source owners and operators will contract for control equipment that is designed to provide a "margin of compliance" with the applicable emission limitation.¹⁶ In addition to reducing the possibility of an exceedance of the limit, this margin is intended to provide flexibility for the source to account for an inevitable control equipment or operational problem. Sources that are able to normally operate with a margin of compliance will lose part of that margin of compliance if they conduct performance testing under normal operations, because they will establish *operating limits* that would require them to continue to over-control forevermore.

[Footnote]

(16) For example, it is relatively common for new ESPs to be purchased with extra fields and sections which will allow the source to continue to operate in compliance with applicable emission limits even when there are problems with other parts of the controls. Fabric filters and scrubbers can also be purchased with extra capacity (*i.e.*, additional modules) for the same purpose.

The only way such sources could avoid surrendering whatever margin of compliance they have would be to deliberately reduce performance of their controls to attempt to generate the least stringent operating limits consistent with achievement of the applicable emission standard. EPA's proposal thus has the perverse result of encouraging sources to focus their attention on learning how to manipulate their operations to allow testing as close as possible to their emission limit by reducing performance of their controls. *See* McRanie Consulting, "Comments on the Proposed Utility MACT Rule - Operating Parameters" (July 2011) (Attachment) at 1-4.¹⁷ [See submittal for McRanie Technical Memo, pages 33-36]

[Footnote]

(17) Although Mr. McRanie's analysis was prepared in response to EPA's proposed EGU MACT, the points he makes are equally applicable to EPA's final IB MACT and reconsideration proposal.

Unfortunately, even the "detuning" of a control device during performance testing will not ensure that the operating limits established during the test are reasonable, or necessary, for achievement of the applicable emission limit. As EPA has previously recognized in the context of the NSPS and the CAM rule, "many sources operate well within permitted limits over a range of process and pollution control device operating parameters," and requiring sources to continuously maintain parameters that "happened to exist" during the most recent performance test may not be "possible or wise." 62 Fed. Reg. 54,900, 54,907, 54,926-27. That is because control device parameters, such as those identified by EPA for scrubbers and ESPs, do not necessarily have a direct relationship to emissions, but instead are interrelated with the design of the control device and the interaction of various parameters. As a result, a single parameter may vary widely with little effect on emissions. Without a clear correlation between such operating parameters and the applicable emission limit, imposition of those values as enforceable limits would unreasonably restrict source and control device operation and subject sources to potential

enforcement without any reliable evidence that an emission limit has been violated. Attachment at 1-4. [See submittal for McRanie Technical Memo, pages 33-36]

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Lee Zeugin and Lauren Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1

Comment Excerpt Number: 35

Comment: Under EPA’s proposal, IB units that use an ESP in combination with a wet scrubber must comply with operating limits on total power input to the ESP collection plates. Proposed § 63.7530(b)(4)(iv). EPA’s proposal is flawed. As Mr. McRanie explains, ESP power input simply is not directly related to PM removal performance, particularly for the modern multisection ESPs that are likely to be installed to comply with a MACT. Attachment at 8-16. [See submittal for McRanie Technical Memo, pages 40-48] The total amount of power is not nearly as important as the location at which the power is being applied in the ESP.

Moreover, none of the ESP parameters are likely to have any relationship to PM at IB units that also have a wet scrubber, since those scrubber systems also are highly effective in controlling high levels of PM coming out of an ESP that is not performing at its intended control efficiency. Attachment at 6-8. [See submittal for McRanie Technical Memo, pages 38-40] As many sources have discovered while attempting to obtain high PM concentrations for PS 11 correlation of PM CEMS, even a fully disabled ESP may have little effect on resulting PM concentrations when a wet scrubber is operating at expected efficiency. Sources should not be penalized for an ESP failure if another control, like a wet scrubber, is capturing the resulting PM.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Lee Zeugin and Lauren Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1

Comment Excerpt Number: 36

Comment: Under EPA’s proposal, IB units that use a wet scrubber must comply with operating limits for pH, pressure drop and liquid flow-rate. Proposed § 63.7530(b)(4)(i) and (iii). EPA’s proposal to use these parameters is subject to the same flaws as EPA’s other proposed operating limits - namely the lack of a sufficient relationship between the parameters measured during performance testing and actual emissions. For example, the range of normal pH in a scrubber can be significant. Attachment at 4. [See submittal for McRanie Technical Memo, page 36] As long as pH is within the normal range, its impact on scrubber efficiency is minor. If pH falls too low, however, metal components can corrode. If pH is too high, calcium sulfate deposits can develop. As a result, operators monitor pH to ensure it is within the desired range and react to bring pH back within that range if pH gets too high or too low. Operators have no incentive to allow pH to

fall outside the normal range. *Id.* Likewise, requiring operators to artificially maintain pH at the level during a performance test is not a useful requirement.

Liquid-flow rate also is not directly related to emissions, but it is related to load. When EPA in 2008 considered the relationship between liquid flow rate and PM in the context of the NSPS for electric steam generating units at 40 C.F.R. Subpart Da, EPA concluded that, at the level of the NSPS (*i.e.*, 0.015 lb/MMBtu), PM emissions controlled by an ESP were not particularly sensitive to the actual liquid flow rate. Response to Public Comments on Rule Amendments Proposed June 12, 2008 (73 FR 33642) (Nov. 2008), EPA-HQ-OAR-2005-0031-0284, § 2.5.3. The determinate factor in SO₂ removal in a conventional spray tower is the liquid/gas ratio (“L/G”), not simply liquid flow. L/G is expressed as gallons per 1000 actual cubic feet of flue gas flow. The rate is usually controlled by adding or removing recycle pumps or scrubber modules as unit load changes. Establishment of a liquid-flow rate limit based on conditions during performance testing will say little about actual emissions under other load conditions. Attachment at 4-5. [See submittal for McRanie Technical Memo, pages 36-37]

Pressure drop also is load dependent. When unit load drops, the scrubber pressure drop decreases as a matter of simple physics because the flue gas flow rate decreases. However, this decrease has nothing to do with removal efficiency. In fact, the scrubber performance is likely to improve at reduced load. In a typical spray tower scrubber, pressure drop is not used for control purposes, but to determine when cleaning of a scrubber module is required. As a result, pressure drop also will increase and decrease according to the cleaning cycle for each scrubber module. Unfortunately, because it is not possible to clean all of the modules at once, operators cannot establish an absolute “minimum” pressure drop for the scrubber during performance testing. *Id.* at 5. [See submittal for McRanie Technical Memo, page 37]

EPA also must recognize that not all scrubbers operate the same way. For example, Chiyoda scrubbers operate on a completely different set of parameters than a typical spray tower. Attachment at 5-6. [See submittal for McRanie Technical Memo, pages 37-38]

In short pH, liquid flow rate, and pressure drop are not particularly useful indicators of emission and may vary based on factors completely beyond the operator’s control. L/G is a more useful indicator for some types of scrubbers (*e.g.*, spray tower scrubbers), but it also will vary with load. Because many boilers operate at variable load levels, establishing operating limits on these parameters based on a single performance test is not reasonable. EPA must adopt a more flexible approach that allows operators to define parameters and ranges based on control device design and the interaction of relevant parameters.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Lee Zeugin and Lauren Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1

Comment Excerpt Number: 37

Comment: Under EPA’s proposal, IB units that use a dry scrubber must comply with an operating limit on dry sorbent (or carbon) injection (“DSI”) rate. Proposed § 63.7530(b)(4)(v)

and (vi). The removal efficiency of a DSI system is directly related to the flue gas concentration of the specific pollutant, the injection rate of the sorbent, and the unit load or flue gas flow rate. Attachment at 16-18. [See submittal for McRanie Technical Memo, pages 48-50] As a result, the DSI rate measured during a performance test also is not particularly useful in determining emissions at other loads. Because the relationship between sorbent injection and load can be characterized more easily than the other control device parameters discussed above, the load adjustment factor provided in the definitions of minimum activated carbon injection rate and minimum sorbent injection rate may be of some use in adjusting a minimum DSI rate to account for changes in load. However, such an adjustment cannot be expected to account for all differences. Similar to boilers using a combination of an ESP and wet scrubber, boilers using DSI also likely will have a secondary control device (*e.g.*, a baghouse or wet scrubber) downstream of the DSI system. EPA should allow sources to take into account the impact of downstream controls when establishing appropriate parameter values and ranges.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Lee Zeugin and Lauren Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1

Comment Excerpt Number: 38

Comment: EPA Should Require Sources To Establish Source-Specific Control Device Parameter Ranges and Enforceable Response Requirements, Not Enforceable Operating Limits. Rather than establish enforceable operating limits, EPA should use the approach taken in the CAM rule (discussed above with respect to PM CEMS) and require sources to establish site-specific operating parameter ranges to define conditions under which compliance with the applicable limit can be reasonably assured. Source owners and operators would then be required to monitor those parameters and respond to changes that indicate problems with the controls that could jeopardize compliance.

Whether using a single control device or combination of devices, sources are in the best position to determine what parameters and levels are consistent with compliance. In many cases, multiple parameter relationships or supplemental operational data will provide a higher level of compliance assurance than the level that happens to be measured during a discrete performance test. This is particularly true for sources with a significant margin of compliance. Attachment at 1- 4. [See submittal for McRanie Technical Memo, pages 33-36] In addition, units with significant margins of compliance should be allowed to establish operating levels by extrapolating parameter data beyond that obtained during a performance test based on other information. Allowing such extrapolations is essential for some sources to provide needed operational flexibility. Attempting to establish “worst case” test conditions on a scrubber or multi-section ESP, where the possible combinations of parameters are numerous, would at the least be difficult and could be impossible without a major research effort. *Id.* Allowing extrapolation of results avoids the necessity of repeated testing.¹⁹ In other cases, an alternative parameter, like SO₂, may be the best indicator of emissions following multiple controls.

[Footnote]

(19) A similar approach has been used in CAM protocols, including a protocol developed by EPRI for ESPs (allowing extrapolation up to 1.25 times the recorded value for measurements taken at less than 80 percent of the applicable emission limit).

Once sources have established appropriate operating parameter ranges based on data collected during performance tests, as well as other operating data and engineering principles, those parameters would be monitored and any deviation from them would trigger a requirement for investigation and corrective action to return the parameter to the appropriate range. Although this range may in some cases be similar to the minimum values that would be established under the current rule, allowing sources to respond with corrective action (rather than simply record and report deviations) achieves EPA's intended result without subjecting sources to potential unreasonable enforcement. Such an approach also would be consistent with the Agency's final EGU MACT rule, which relies on other requirements (including the CAM rule) to ensure proper operation of controls in between performance stack tests. 77 Fed. Reg. at 9384.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Lee Zeugin and Lauren Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1

Comment Excerpt Number: 49

Comment: The control device operating parameter procedures do not recognize any margin of control for the control devices. As a general rule sources buy control equipment with an "operational" margin of compliance so that there is flexibility to account for control equipment problems or other operational issues. There will be problems because control equipment is just made up of mechanical and electrical hardware and failures will occur. Therefore, most electrostatic precipitators (ESPs) are bought with extra fields and sections where the source can operate in compliance with the applicable emission regulations even when there are problems with parts of the control equipment. Likewise, fabric filters (FF) or baghouses and scrubbers are often bought with extra capacity (additional modules) in the control equipment.

The control device operating parameter procedures in EPA's proposal call for setting the maximum and/or minimum (as appropriate) parameter value based on the conditions that exist during the performance test. If the performance test is just barely in compliance with any emission limit, and the assumption is that the emissions are directly related to the control device operating parameters¹, this approach might be acceptable. However, many performance tests are performed at a level of control that not only includes a significant margin of compliance, but that also may not be directly correlated to control device operating parameters. Unfortunately, control device parameters, especially with scrubbers and ESPs, are interrelated with the design of the device and the interaction between the various parameters. For example, total ESP power may be completely unrelated to ESP performance for a multi-section ESP. Total ESP power is, therefore, not an appropriate indicator for ESP performance except for the most simple, single chamber ESP. The ESP power issues are discussed more fully later in this memorandum.

Control device operating parameters may vary widely with little effect on the emission rate of the pollutant being controlled. In addition, normal operation of emission control devices contains considerable variability. For example, on a scrubber the pressure drop and liquid flow rate are usually a function of boiler load. As a result, recording of control device parameters at levels above or below those recorded during a performance test might be consistent with good operation of the control device and compliance with the standard. EPA's failure to consider this normal operational variability in the proposed rule could make the proposed standard much more stringent than the proposed numerical limit and could interfere with operation of the control device.

If EPA deems it necessary to specify both an emission limit and control device operating parameter, the operating parameters and levels should be identified by the source based on a variety of factors specific to the source and used to determine whether corrective action is required. Operation outside of an operating parameter limit should not be considered noncompliance with the MACT limit because it does not necessarily mean that the numerical emission limit established as the MACT has been exceeded. Instead, EPA should adopt an approach similar to the one in EPA's Compliance Assurance Monitoring (CAM) (40 C.F.R. Part 64) rule.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Lee Zeugin and Lauren Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1

Comment Excerpt Number: 50

Comment: The only way to set control equipment parameters at the level recorded during performance testing and still maintain the equipment control margin is to perform a CAM type exercise with multiple tests and the control equipment performance degraded. This testing procedure should be specifically allowed and any emission excesses during the testing should be specifically excused in the rule.

I have conducted a number of CAM tests on particulate control devices and, thus, has considerable experience in this area. In many cases, I find that the State Agency or EPA regional office is very nervous about allowing the performance of the control equipment to be degraded, only for the purpose of CAM testing, to approach the level of the standard. In fact, I have been told by some state regulators that such action would not be allowed. The proposed EGU MACT rule states that, "You must conduct performance tests at the maximum normal operating load while burning the type of fuel or mixture of fuels that has the highest content of chlorine, fluorine, non-Hg HAP metals, and Hg, and you must demonstrate initial compliance and establish your operating limits based on these tests. These requirements could result in the need to conduct more than one performance test."

While this rule language implies that the control equipment can be detuned for the performance tests, it should be explicated stated. In addition, the parameter testing/setting procedure contemplated by EPA in this proposed rule cannot be accomplished unless the source is shielded

from excess emissions during the performance tests. Control device performance can be variable based on a number of different operating parameters and is certainly not precisely predictable in advance. Therefore, it is possible that the control device will inadvertently be detuned to the point that emissions over the limit will be measured. Under such circumstances, the excess emissions should be explicitly excused by the rule.

If excess emissions are not permitted during the performance/parameter setting test period, EPA will be removing compliance margin from the control device and penalizing the source. Surely, this is not EPA's intent.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Lee Zeugin and Lauren Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1

Comment Excerpt Number: 51

Comment: Sources that demonstrate a significant margin of compliance during performance testing should be allowed to use other data and information to extrapolate control device parameter levels to a point that would trigger corrective action.

The rule should provide source operators flexibility in the parameter or operating data that can be used to demonstrate proper operation of the control device and a reasonable assurance of compliance rather than dictate the parameters to be used. In addition, sources should be allowed to extrapolate parameter data beyond that obtained during the performance test based on information gathered during the performance test period. This is particularly true for sources that have a wide compliance margin, as will likely be the case for new control equipment. Since there is only a loose relationship between a given operational parameter and the emission rate on many control devices, multiple parameter relationships or supplemental operational data usually provide a higher level of compliance assurance.

We can use the simple example of an ESP to explain this concept. ESP compliance/performance tests are normally conducted near full boiler load because the performance of an ESP is at a minimum with full gas flow and dust loading. The performance of an ESP improves dramatically when the boiler is at 50% load. Therefore, an operational limitation on ESP power developed during a full-load compliance test is not valid when the load is at 50%. A similar example could be made for scrubber pressure drop.

Allowing extrapolation of appropriate operating parameters based on sound engineering and technical practices will be essential to prevent penalizing sources that have a wide margin of compliance and to provide sources with needed operational flexibility. When one considers the possible test matrix to simulate the worse case test condition on a scrubber or multi-section ESP, the combinations are huge. The performance test could become a major research project. The approach of using data extrapolation to initiate corrective action has precedence within the agency. Many compliance assurance monitoring projects have utilized parameter extrapolation to define corrective action levels and excursions.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Lee Zeugin and Lauren Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1

Comment Excerpt Number: 52

Comment: EPA proposes to require monitoring the pH of the scrubber slurry as an operating limit. pH is not very useful as an operating limit because of necessary operational variability. In a conventional spray tower limestone scrubber the pH of the scrubber slurry is typically held in the range of 5.4 - 6.0 to prevent corrosion and deposition in the scrubber. A pH below this range accelerates corrosion of metal components and pH above this range encourages development of CaSO₄ deposits in the scrubber. Within that pH range, the pH has a very minor impact on the SO₂ removal rate of the scrubber. The pH is held in the desired range by the continuous addition of concentrated limestone slurry and the removal of spent scrubber liquor.

If the limestone slurry feed is disrupted, the pH in the reaction/slurry tank will begin to drop over the next one to two hours. For example, over a 2-hour period, the pH may drop from about 6.0 to about 5.0. Note that the actual drop in pH will depend on a variety of factors. In this scenario, there are two important points,

1. Data indicates that the SO₂ emissions do not change significantly within this range of pH values, and

2. Before the pH drops any further, the operator will take steps to resolve the problem or shut down the module serving that reaction/slurry tank. The operator does not have any incentive to operate the tank/module at low pH values. This is not an issue of “reducing operating costs.” Limestone is not very expensive, and if the pH gets too low, substantial damage (corrosion) to major scrubber components may result.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Lee Zeugin and Lauren Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1

Comment Excerpt Number: 53

Comment: When EPA discusses monitoring “liquid flow-rate” in proposed Subpart UUUUU, Table 4, it is not clear what liquid they are describing. Presumably, EPA is referring to the scrubber slurry flow rate. (Note that there are also editorial errors in the table – e.g., “...the pH at or above the lowest 1-hour pressure drop...”).

The scrubber slurry rate is not to be confused with the limestone slurry flow rates (i.e., the makeup slurry used to control the reaction/slurry tank pH). Limestone slurry feed rates are monitored – typically using magnetic flow meters (also referred to as “magmeters”) or some

other comparable type of meter. The limestone slurry flows are very small relative to the scrubber slurry flows (e.g., 100 gpm v.s. 160,000 gpm for an 800 MW unit).

The determinate factor in SO₂ removal in a conventional spray tower is the liquid/gas ratio (L/G) expressed as gallons per 1000 actual cubic feet of flue gas flow. The recirculating liquid flow rate is usually controlled in discrete stages by adding or removing the number of recycle pumps or scrubber modules in service as the unit load changes. Therefore, the L/G might vary with load at a given scrubber efficiency. If EPA wants a parameter for evaluating scrubber performance, the liquid to gas (L/G) ratio, not just the liquid flow rate, should be used (i.e., the number of pumps in service times the liquid flow rate per pump divided by the exhaust gas flow rate).

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Lee Zeugin and Lauren Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1

Comment Excerpt Number: 54

Comment: EPA also proposes to require the monitoring of scrubber pressure drop. When unit load drops the scrubber pressure drop decreases as a matter of simple physics because the flue gas flow rate decreases. However, the decrease in scrubber pressure drop has nothing to do with the SO₂ removal rate in the scrubber. When the pressure drop falls below some minimum value observed during testing, it does not mean that the scrubber is not performing properly.

For typical spray tower scrubbers, the pressure drop is not used for control purposes. Pressure drop is used to determine when cleaning is required. Most scrubber operators develop a maintenance schedule for cleaning the scrubber modules based on pressure drops. Consequently, the pressure drops increase and decrease according to the cleaning cycle for each module. They are not necessarily accurate for assessing scrubber performance. When a module requires cleaning, the utility will take it offline (usually overnight) for maintenance while the other modules remain online.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Lee Zeugin and Lauren Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1

Comment Excerpt Number: 55

Comment: EPA Must Recognize That Not All Scrubbers Operate the Same Way.

The Chiyoda scrubber operates somewhat differently than does a spray tower scrubber described above. An important difference is that there is no L/G defined because the Chiyoda scrubber vessel has no recirculating slurry spray and is essentially a giant bubbler called a Jet Bubbling Reactor (JBR). The JBR combines the concurrent chemical reactions of limestone dissolution,

SO₂ absorption/neutralization, sulfite oxidation, gypsum precipitation and gypsum crystal growth in a single vessel. Therefore, auxiliary vessels and large recirculation pumps are eliminated.

Flue gas enters the scrubber through a large number of “sparger” tubes below the liquid level in the scrubber vessel and bubbles up to the surface of the liquid and through a thick “froth” layer that forms on the surface of the liquid. The Chiyoda scrubber typically operates at a lower pH than does a spray tower. This is possible because the scrubber vessel and virtually all of the vessel internals are made of fiberglass or plastic. Therefore, the corrosion issues that exist with a spray tower are not a serious issue with a Chiyoda scrubber. In addition, the low pH (3.5-5.0) operation has a number of positive operational impacts. Limestone utilization is high and froth level is high, which enhances SO₂, particulate and mercury removal. The low pH also inhibits Al-F blinding, which interferes with limestone dissolution.

The control scheme for a Chiyoda is a combination of pH and liquid depth above the sparger tube exits. The optimum pH depends on the scrubber liquid, coal, flue gas and ash chemistry. The liquid depth is then adjusted to achieve the desired level of SO₂ control. In some cases it is more convenient to fix the liquid depth and adjust the pH as a control function. A third factor that is in play is the gypsum crystal density in the scrubber liquid, which affects the slurry removal rate from the scrubber vessel. Obviously, the slurry removal rate also affects the pH and liquid depth in the vessel.

In summary, there are a variety of operational parameters and control elements associated with the operation of a Chiyoda scrubber. All of the parameters have a range of operation that will result in successful scrubber operation and it is necessary to adjust the parameters to match the fuel being burned and the flue gas characteristics. As with a spray tower scrubber, it is impossible to match any operating parameter to a fixed parameter operating point as is contemplated by the operating limits in the proposed utility MACT rule.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Lee Zeugin and Lauren Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1

Comment Excerpt Number: 56

Comment: EPA Should Recognize That Operating Parameters Are Not Useful Indicators For Wet Scrubbers

A modern wet scrubber removes virtually 100% of the entering HCl, HF, oxidized Hg and particulate with just water (no limestone) as the reagent. This happens because HCl, HF and oxidized Hg are all either highly soluble or 100% miscible in water alone. The particulate is removed by impaction with the scrubber spray droplets and many studies have shown very high levels of particulate removal at normal scrubber operating conditions. In fact, a scrubber has to be operated in a severely degraded manner to achieve significant particulate penetration.

In 2004, RMB conducted a “wet stack opacity” development project³ for EPRI at the Trimble County Plant of LG&E. During this project, a device was designed that extracted an isokinetic flue gas sample for the stack, dried the sample and then measured the opacity using a conventional opacity monitor. Towards the end of the project a series of experiments were performed to evaluate the impact of ESP outlet opacity on stack opacity and mass emissions. The tests were done in two phases as described more fully below.

As a part of the test program, the ESP was partially disabled to determine the impact of increased scrubber inlet particulate on the outlet opacity. Table 1 shows the results of those tests.

[See submittal for Table 1 – Preliminary Opacity Tests for data table provided by the commenter]

Test 1 was the starting point before any ESP electrical sections were disabled and the starting ESP opacity was 7% and the stack opacity was 0.5%. For Test 2 a number of ESP sections were completely turned off to increase the ESP outlet opacity and to evaluate the impact on the stack opacity. The opacity was 16% opacity on the ESP outlet and 1.1% at the stack. At this point, scrubber recycle pumps were removed from service to reduce spray in the scrubber modules. For Test 3, ESP capacity was further reduced and scrubber recycle pumps were reduced from 5 pumps to only 2 pumps per scrubber module (a 60% reduction in L/G). The stack opacity only increased from 1.1% to 1.3%. Unfortunately, the experiment had to be stopped because the SO₂ emissions had increased substantially and there was potential for an SO₂ emissions violation.

Since no significant amount of particulate could be made to penetrate the scrubber without an opacity⁵ and SO₂ violation, it was necessary to obtain a variance from the state before further tests could be done.

After the variance was obtained, the Phase 2 experiments were conducted at very high ESP outlet opacity (40-50%) and a minimum number⁶ of scrubber recycle pumps operating. The Phase 2 tests included Method 5B particulate tests at the stack. The fundamental conclusions did not change after the Phase 2 series of tests. It is very difficult for particulate to penetrate a modern, high efficiency SO₂ scrubber. During normal scrubber operation changes in the ESP outlet particulate loading or opacity have little direct effect on the stack particulate emissions. In addition, when the number of scrubber recycle pumps is decreased, the SO₂ emissions increase rapidly. Table 2 shows the results of the Phase 2 tests.

[See Table 2 – Phase 2 Opacity and Mass Tests for data table provided by the commenter]

As with the preliminary tests, Test 1 is the baseline condition with all available ESP sections in service and the SO₂ scrubber operating normally. The test conditions for Tests 2-3 were created by removing various combinations of ESP sections and scrubber recycle pumps.

I believe these tests clearly illustrate that SO₂ removal is the most difficult job performed by the scrubber. The Phase 2 data show that the SO₂ emissions increased by a factor of 10 from the baseline to the most degraded condition while the particulate emissions only increased by a factor of 2. This is understandable since SO₂ removal requires mass transfer of the SO₂ molecules to the scrubber liquid and then a chemical reaction to form CaSO₃. Given the high solubility and/or completely miscible chemical characteristics of HCl, HF and oxidized Hg, it is safe to assume that the scrubber removed virtually 100% of those compounds, even in the most

degraded condition. Therefore, almost any scrubber operation considered normal for the unit would be sufficient to demonstrate proper scrubber operation for removal of all of the compounds, as well as for particulate removal. For a unit using SO₂ as a surrogate for HCl, if the scrubber is exhibiting operation consistent with the proposed SO₂ limit, operating parameters like pH, pressure drop and L/G are just not relevant. For a unit not using SO₂ as a surrogate, scrubber operation consistent with meeting any applicable short term SO₂ limit should also be more than sufficient to ensure removal of the soluble and miscible compounds.

[Footnotes]

(3) "Evaluation of an Extractive Opacity Monitor for Wet Stack Applications", EPRI, Palo Alto, CA: 2005.

1012945

(5) Opacity is limited to 20% at the ESP outlet.

(6) It is essential to keep at least two recycle pumps operating on each module to protect the fiberglass scrubber outlet ductwork.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Lee Zeugin and Lauren Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1

Comment Excerpt Number: 57

Comment: A Discussion of ESP Performance Relative To Power and Sectionalization - ESP Power Relationships and a Simple Example

The amount of power^{7,8} that can be applied in any section of the ESP varies from inlet to outlet section. One of the unusual, and fortunate, features of an ESP is as the gas moves through the ESP from section to section, the amount of power that can be applied increases in each subsequent section. This is because the amount of particulate matter in the gas stream is being reduced as the gas moves from the inlet of the ESP to the outlet. In general, the particles in the flue gas form a barrier to charged ions that are moving to the collection plates. As the gas flows through the ESP, and more particles are removed, more current can be applied.

Total ESP power input and corresponding particulate removal effects can be analyzed by using an ESP performance computer model. There are several models available and all of the models work in a similar fashion.⁹ The models are based on fundamental scientific principles and incorporate size specific particle charging and migration, turbulent flow particle collection and other theoretical concepts that have been developed by researchers worldwide. These models have been shown to work very well in predicting a specific ESP's performance, over a limited range, when calibrated to that specific ESP¹⁰ to account for real world, non-ideal conditions.¹¹ The performance that might be expected when a specific operational factor is changed and all other operating parameters are held constant.

This can be done for a variable like total ESP input power because all other ESP parameters and variables can be held constant so that only the total power is changed. In the various analysis cases that are discussed below, the EPRI ESPM model has been used. A simple example case has been setup that uses input that would be similar to that of a real ESP. The ESP example is a simple, single chamber, four-field unit as illustrated by Figure 1.

[See submittal for Figure 1 – Simple ESP Example for diagram provided by the commenter]

The ERPI ESPM model was setup using the input below.

Number of fields in direction of gas flow = 4

SCA = 270 ft²/1000 acfm

Plate height = 30 ft

Field Length = 9 ft

Total Length = 36 ft

Plate-to-plate spacing = 9 in

Wire-to-wire spacing = 9 in

Gas velocity = 6 ft/sec

The field voltages and currents were then applied based on past field experience. This resulted in the power levels shown in Table 3.

[See submittal for Table 3 – Field Power Levels for data table provided by the commenter]

The model was then run with four fields in service, followed by runs with three fields, then two fields and then one field in service. This allows us to calculate the sequential particulate removal contribution of each ESP field. This simulates exactly what happens in the field with a real ESP. The results of this series of model runs are shown in Table 4.

[See submittal for Table 4 – Cumulative Particle Removal for data table provided by the commenter]

It can be readily seen that the particulate removal effectiveness in terms of pounds of particulate removed per kilowatt of ESP input power is much higher in the inlet field of the ESP relative to subsequent fields (on a cumulative basis). This result is completely consistent with ESP charging, collection and rapping reentrainment theory. Particle charging and collection occur very rapidly when the flue gas enters the ESP, so it is only logical that considerable collection takes place in only a few feet. This is clearly illustrated in Table 2 where the model calculates that over 74% of the particulate matter is removed from the gas stream in the first nine-foot field. It should also be noted that the effect shown in Table 2 is cumulative when there is more than one field in service. For example, the 233 lb/kW particulate removal value is for the combined total power of the first two (A+B) fields. If the calculation is performed on an individual field basis, to evaluate the pounds of particulate removed in that field alone, the results are much more dramatic. The results of such a calculation are shown in Table 5.

[See submittal for Table 5 – Individual Field Particle Removal for data table provided by the commenter]

What has been done in Table 5 is to take the amount of particulate removed in each individual field¹³ and divide by the power applied in each individual field¹⁴. The particles that exit Field A and enter Field B are a combination of the more difficult to collect particles because they primarily consist of finer particles, and rapping reentrainment.¹⁵ As the gas stream moves through the ESP there are fewer and fewer particles to collect and, at the same time, more power can be applied in the downstream ESP sections. The result is that less and less particulate mass is available to be collected in each subsequent field, no matter how much power is applied.

The clear conclusion that must be drawn for this analysis is that a kilowatt of power is not related to particulate removal except in a gross manner. The total amount of power is not nearly as important as the location at which the power is being applied in the ESP.

This is, of course, a very simple example to illustrate how applied power effects particulate removal in an ESP. In an actual ESP, the situation is much more complex because there are multiple chambers and fields.

[Footnotes]

(7) For this discussion, power is given the simple definition of transformer rectifier (TR) set secondary volts times secondary amps equals watts. For convenience, I will use standard ESP nomenclature of secondary kilovolts times secondary amps to equal kilowatts.

(8) Many ESPs are not equipped with TR secondary power metering and use only primary power indication. Primary power indication is more than satisfactory for day-to-day operation of the ESP.

(9) The primary models in use include the EPRI ESPM Model, the Environmental Protection Agency (EPA) ESPVI Model and the Southern Research Institute Model. The programmer of the EPRI and EPA models was the same person, Dr. Phil Lawless of Research Triangle Institute; therefore, the core code and results are very similar.

(10) Compliance Assurance Monitoring Protocol Development: Site Test Report, EPRI Report TR-111478, 1998

(11) The models are typically calibrated by adjusting values in the model to account for rapping reentrainment and velocity standard deviation. These values vary from ESP to ESP but usually fall in normal ranges depending on the age, design and size of the ESP.

(13) The pounds of particulate removed in each individual field are derived by subtracting the total particulate removed at each interval shown in Table 4.

(14) See Table 3.

(15) Rapping reentrainment consists of particles that have been previously collected but are resuspended in the gas stream when the collecting plates and wires are rapped to dislodge collected material.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Lee Zeugin and Lauren Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1

Comment Excerpt Number: 58

Comment: The amount of sectionalization in an ESP is another factor that significantly influences ESP performance. The simple example ESP that was discussed previously was a four section ESP that has a collection area of about 50,000 ft²/section. Such an arrangement for a large ESP would be very unreliable because any broken wire¹⁶ would disable the entire section and then there would be only three sections in service, which would result in a significant increase in emissions. To maximize ESP reliability and overall performance, it is general practice to limit the plate area in an ESP section to 12,000 - 25,000 ft².¹⁷ Therefore, an ESP of the size of the simple example would likely be built in mechanical and electrical sections as a 3X4, 4X4, 3X5 or 4X5 ESP¹⁸. A likely arrangement would be with a 4X4 section arrangement as shown below in Figure 2. [See submittal] Granted, many modern ESPs were built with significantly more sectionalization than the simple 4X4 arrangement used in this example. This example is useful to illustrate the problem with total power as an indicator of ESP performance and the problem simply becomes magnified with more sections.

[See submittal for Figure 2 – 4X4 ESP Example for diagram provided by the commenter]

Since there are 16 sections in a 4X4 ESP arrangement, if there is an electrical or mechanical problem with one section of the ESP, it only affects 6.25% of the collection area. This greatly improves the reliability of the ESP.

It can be readily noted from Figure 2 [of the submittal] that, no matter what path the flue gas takes through the ESP, it flows through 4 sections arranged in series.¹⁹ This greatly improves ESP performance because each section has its own high voltage transformer/rectifier (TR) set and is electrically isolated from the other sections. Not only does this provide improved reliability; it also improves particulate removal performance because the electrical conditions, or power level, can be optimized in each section.

It is a simple mathematical exercise to analyze the performance of the total ESP under a variety of powering arrangements if the sectional efficiency and emission rate of each ESP section is known. To simplify the experiment, I have assumed that the efficiency and, conversely, emission rate, as well as the ESP power are exactly the same as that used in the simple ESP example.²⁰ The diagram in Figure 2 [of the submittal] can be redrawn to contain each section's emission rate²¹ and power.

[See submittal for Figure 3 – 4X4 ESP Emission rate and Power for diagram provided by the commenter]

To analyze the total performance of this ESP with all sections in service, as shown in Figure 3 [of the submittal], we average the final particulate emission rate of all four lanes and total all of the power. So the equation for emission rate becomes:

$$(0.048+0.048+0.048+0.048)/4 = 0.048 \text{ lb/mmBtu}$$

And the equation for power becomes:

$$(20.00+36.30+46.15+53.25)*4 = 622.8 \text{ kW}$$

Using this exact same procedure, we can now evaluate a number of different section failure scenarios. The first example is what happens when one of the outlet fields in the ESP shorts out because of a broken wire. This short has been shown in Figure 4 by a shaded section.

[See submittal for Figure 4 - 4X4 ESP With One Outlet Section Out-Of-Service for diagram provided by the commenter]

The calculation for emission rate is the same as above except the emission rate and power for only the three fields in service are counted for the lane with the shorted section. The equation for emission rate becomes:

$$(0.048+0.048+0.048+0.143)/4 = 0.072 \text{ lb/mmBtu}$$

The equation for power becomes:

$$(20.00+36.30+46.15+53.25)*3 + (20.00+36.3+46.15) = 569.55 \text{ kW}$$

In the next example there are two outlet sections out-of-service, and this is shown in Figure 5 [see submittal]. As before, shading is used to denote the out-of-service sections.

[See submittal for Figure 5 - 4X4 ESP With Two Outlet Sections Out-Of-Service for diagram provided by the commenter]

The calculation for emission rate is again the same as above except the emission rate and power for only the three fields in service for two lanes are counted. The equation for emission rate becomes:

$$(0.048+0.048+0.143+0.143)/4 = 0.096 \text{ lb/mmBtu}$$

The equation for power becomes:

$$(20.00+36.30+46.15+53.25)*2 + (20.00+36.30+46.15)*2 = 516.3 \text{ kW}$$

Of course, another example of two fields being out-of-service can be setup except this time we will look at the case where two fields in the direction of gas flow are out. A graphic example of this case is shown below in Figure 6.

[See submittal for Figure 6 - 4X4 ESP With Two Sections Out-Of-Service in Series for diagram provided by the commenter]

The equation for emission rate in this example becomes:

$$(0.048+0.447+0.048+0.048)/4 = 0.148 \text{ lb/mmBtu}$$

The equation for power becomes:

$$(20.00+36.30+46.15+53.25)*3 + (20.00+36.30) = 523.4 \text{ kW}$$

Clearly, if the example shown in Figure 5 [of the submittal] is compared to the example shown in Figure 6 [of the submittal], it can readily be seen that the total ESP power is not directly related to particulate emission rate. The power is lower in the Figure 5 example while the emission rate is also lower. The reason for this is simply that power applied closer to the ESP inlet is more effective in removing particulate from the gas stream.

This comparison is even more dramatic where a scenario in which four fields are out-of-service is examined. These two examples are shown in Figures 7 and 8 [of the submittal]. In the first case, all four outlet fields are out-of-service and, in the second case, two fields have been removed in series.

[See submittal for Figure 7 - 4X4 ESP With Four Outlet Sections Out-Of-Service for diagram provided by the commenter]

[See submittal for Figure 8 - 4X4 ESP With Two Sections In Series Out-Of-Service for diagram provided by the commenter]

The equation for emission rate in the Figure 7 example is:

$$(0.143+0.143+0.143+0.143)/4 = 0.143 \text{ lb/mmBtu}$$

The equation for power is:

$$(20.00+36.30+46.15)*4 = 409.8 \text{ kW}$$

The equation for emission rate in the Figure 8 example is:

$$(0.048+0.447+0.048+0.447)/4 = 0.248 \text{ lb/mmBtu}$$

The equation for power is:

$$(20.00+36.30+46.15+53.25)*2 + (20.00+36.30)*2 = 424.0 \text{ kW}$$

In this case, the particulate emission rate for the Figure 8 example is 73% greater than the Figure 7 example even though the power is 3% higher. It is also interesting to note that the emission rates in Figures 6 and 7 are almost exactly the same even though the ESP power levels differ by more than 25%. Table 6 summarizes these examples.

[See submittal for Table 6 - Summary of ESP Performance Examples for data table provided by the commenter]

The point of these multiple examples is to show that total ESP power input is not directly related to particulate removal performance – especially in modern multiple section ESPs. In fact, the more highly sectionalized the ESP, the more difficult it is to relate power to ESP performance. Some larger ESPs have six to eight fields in the direction of gas flow and eight to twelve sections across gas flow.

[Footnotes]

16 The leading cause of ESP section failure is broken wires that short out the electrical system.

17 The mechanical and electrical arrangement of ESPs installed on boilers includes a broad spectrum of designs. The design criterion in the text is the author's opinion concerning appropriate design.

18 The first number is the number of sections across and the second number is the number of sections deep.

19 Various gas flow control devices like perforated plates, turning vanes and channel baffles are used in the ductwork ahead of the ESP to spread the gas flow evenly across the face of the ESP.

20 This simplifying assumption is not likely to occur with a real ESP but it does not change the basic conclusions of the calculations.

21 Emission rate is the particulate concentration in lb/mmBtu at the exit of each ESP section. See Table 2.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Lee Zeugin and Lauren Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1

Comment Excerpt Number: 60

Comment: Dry sorbent injection (DSI) and activated carbon injection (ACI) systems are dry powder injection systems that are designed to control specific stack emissions. DSI systems typically inject trona or sodium bicarbonate for the control of SO₂, SO₃, HCl and HF. The primary use for DSI systems in a modern coal-fired power plant is for control of excessive SO₃ created by selective catalytic NO_x control devices. ACI systems inject activated carbon primarily for the control of Hg, however; the activated carbon also adsorbs SO₃ as well. Both types of systems operate on the principals of chemical reaction and/or adsorption.

In general, the designs of DSI and ACI systems are very similar. An air blower exhausts into a manifold and distribution piping that feeds injection piping located at intervals in the flue gas ductwork. The sorbent material is fed into the manifold and carried by the air stream to be evenly distributed in the duct as the flue gas flows past the injection piping. Various manifold and injection piping designs are used to ensure the even distribution of sorbents into the flue gas.

The removal efficiency of a DSI or ACI system is directly related to the concentration of the specific pollutant in the flue gas, the injection rate of the sorbent and the unit load or flue gas flow rate. Whether discussing DSI or ACI, each specific installation has an efficiency curve shape similar to those shown below in Figure 9²³.

[See submittal for Figure 9 – Performance of Sodium Bicarbonate in SO₂ Mitigation for diagram provided by the commenter]

These curves are developed during initial setup of the DSI/ACI system and are linear over much of the range. While the DSI curve in Figure 9 uses normalized stoichiometric ratio (NSR) as the units for the X-axis, ACI systems typically use pounds of sorbent per million actual cubic feet (lb/MMacf) of flue gas flow. The decision of whether a very technical operating parameter such as NSR or lb/MMacf is used, or a fairly simple operating parameter such as percent load or percent flue gas flow is used, should be left to the source. Unfortunately, the option of varying the sorbent injection rate with load or flue gas flow rate was not included in the proposed EGU MACT rule.²⁴ The “load fraction” concept used in the industrial boiler MACT rule is available for dry sorbent or carbon injection. The concept is very simple; it is just a percent of heat input. The heat input where the compliance test is performed becomes 100% feed rate for the sorbent. At lower loads the source can reduce the feed rate proportional to heat input and remain in compliance with the operating limit. The load fraction option should be added to the EGU MACT rule to prevent overfeeding of the sorbent at lower loads.

It should also be noted that a unit equipped with DSI or ACI will also have secondary emissions control provided by downstream control devices like baghouses and scrubbers. For example, Figure 9 shows approximately 90% SO₂ capture at a NSR of 1.5 when DSI, using sodium bicarbonate, is followed by a baghouse. Since both HCl and HF are more reactive than SO₂, even higher capture performance should be expected for HCl and HF. In addition, wet scrubber equipped units have no need for a DSI or ACI operating limit. Scrubbers remove virtually 100% of the HCl and HF in the flue gas. The Hg emissions will be directly measured so there is no need for an ACI operating limit.

[Footnote]

(23) Courtesy of Solvay Chemicals, Inc. – It should be noted that this curve is generic and that there is no information about the specific coal being used, the ash chemistry or the size of the ESP or baghouse reflected by the curve. Therefore, conclusions about the performance of DSI on any specific unit should not be made based on this curve.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 59

Comment: *EPA Should Provide Flexibility in Determining Appropriate Fuel Input Operating Limits*

The general compliance plan outlined in the Reconsideration Proposal requires that sources: (1) demonstrate compliance with applicable emissions limitations and work practice standards through the conduct of an initial performance test; (2) establish operating limits based upon results of the performance test; (3) conduct monitoring and maintain records demonstrating that the source is operated on a continuous basis consistent with the operating limits established during the performance test; and (4) periodically repeat the performance testing. Operating parameter limits based on fuel input analysis (e.g., HCl and Hg), are established using Equations

7 and 8 in § 63.7530. Then, on a continuing basis, facilities are required to keep extensive records of all fuels burned in each boiler or process heater during each compliance reporting period. If a source changes fuels, it must re-calculate its fuel input values using applicable equation 7 or 8. If the re-calculated value exceeds the existing limit, the source is required to conduct a new performance test and establish new operating limits.

While this compliance approach may be easy to manage for some sources, especially ones with very stable fuel supply and usage, it may be very cumbersome and burdensome for other sources with variable fuel suppliers and fuel mixes. This approach involves a great deal of recordkeeping and potentially subjects the source to frequent testing requirements if fuel content varies, regardless of the margin of compliance shown during the initial performance test. Under the proposed rule, even if a unit is operating at 50 percent of the applicable emission limit, the facility would be required to re-test if the fuel chloride input increases 1 percent over the level achieved during the initial performance test.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 60

Comment: A more appropriate approach is to allow the source to set operating parameters at levels that generate emissions at the emission limits established in the rule. This is the only approach which meets the requirements of the Act, since it is the only approach that does not impose a beyond the floor limit which has not been justified per the requirements of § 112(d). Under this approach, the source would do the performance test using its normal fuel mix, determine operating conditions that show compliance and then adjust those conditions, using engineering calculations to assure it would meet the emissions standards established in Table 1 or 2. If the initial performance test shows emissions at 50 percent of the standard at a particular mercury or chloride fuel input, the fuel input limits should be set at a level higher than the performance test values, taking into account control device operating parameters as appropriate. This approach would be environmentally beneficial and would greatly reduce burdens. It is the only practical way to establish fuel input operating limits.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 61

Comment: Compliance could also be demonstrated through the use of fuel purchase specifications. Sources would determine from the performance test a maximum fuel pollutant concentration at which the emissions limitations are achieved. For instance, the performance test

may demonstrate that fuels containing chlorine in concentrations less than x lb Cl/MMBtu allow the source to comply with emissions limitations. A facility should be allowed to extrapolate an allowable fuel input based on a comparison of performance test conditions to the applicable emission limit. The source would then set a fuel specification of x lb Cl/MMBtu and would be allowed to burn any fuel of the same general type (e.g., solid, liquid, or gas) as long as it met this specification. Sources could require that the fuel supplier provide periodic certification that the fuel meets the specification, based on analysis, or could establish an internal sampling and analysis program for that purpose. In any case, where common fuels are utilized in more than one unit, common fuel quality data would be maintained and considered applicable to all such units. Continuous compliance could also be demonstrated through ongoing fuel analysis.

As an example, sources would (1) establish a fuel input limit (e.g., lb Cl/MMBtu) based on the compliance test as described in the proposal (with an allowance for extrapolation); (2) periodically sample and analyze each fuel for constituent concentration and heating value according to a specified sampling and analysis plan; (3) monitor the daily usage of each fuel; (4) calculate the average total daily constituent input (lb/MMBtu) accounting for all fuels fed; and (5) demonstrate that the average daily constituent input rate averaged over each month of operation does not exceed the operating limit. This option would afford the source the opportunity to vary fuel mixes, while still insuring that protective operating limits are met.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 62

Comment: *Additional Flexibility is Needed for Determining Appropriate Sorbent Injection Rates*

The Reconsideration Proposal requires development of operating parameter limits (OPLs) based on the values achieved during the performance test. In many cases, these levels will be appropriate only for certain modes of operation. For example, the absolute sorbent injection rate observed during the performance test conducted under full load and using the worst case fuel mix will not correlate to the sorbent injection rate necessary during startup or periods of lower load. Frequently, sorbent injection rates are set using a feedback loop from a CEMS or CPMS to avoid wasting sorbent.

EPA has acknowledged that the sorbent injection rate will vary with load in Table 7 of the Reconsideration Proposal, which allows sources to adjust the sorbent injection rate by a load fraction. However, as EPA requires sources to test at the worst case fuel mix for chloride and mercury and this fuel mix may differ from the typical day to day fuel mix, EPA should also allow adjustments to sorbent injection rates based on fuel mix. For example, if a boiler is capable of burning both coal and biomass and tested at 100% coal firing for the mercury performance test, the carbon injection rate for periods of normal operation should not only be adjusted based

on load but also by the percentage of coal being fired. If a boiler is burning natural gas or other clean fuel during a certain operational period, sorbent injection is not necessary.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 63

Comment: *Additional Flexibility is Needed for Other Operating Parameters*

In Table 7, EPA only allows for operating parameter limit variation due to boiler/process heater load fraction to be applied to sorbent and activated carbon injection rates. However, variations with load and other operating conditions also occur for the other operating parameters- wet scrubber pressure drop, pH, and liquid flow rate, ESP voltage and secondary amperage. Flue gas flow rate and characteristics vary over load and with other operating variables such as fuel quality, to the extent that the single hourly average value determined during the high load steady state performance test will not apply to other conditions if overall performance is optimized. EPA should provide an allowance for any operating parameters to vary with unit load fraction as applicable to the operating parameter and specific affected source, and recognize that those operating parameters do not necessary vary in a linear relationship with load, e.g., pressure drop typically varies with the (flow)².

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Chris M. Hobson

Commenter Affiliation: Southern Company

Document Control Number: EPA-HQ-OAR-2002-0058-3520-A1

Comment Excerpt Number: 10

Comment: Southern believes that operating and fuel limits should only provide that control technology and fuel is being operated and used in a manner consistent with its operations during performance testing. The operating and fuel limits proposed by EPA go well beyond this purpose and place an undue burden on boiler operators. For example, the method of establishing operating limits requires a "worst case" of three hourly averages attained during the performance test for very specific operating parameters for each control technology. This method of setting the operational limit is too prescriptive and gives no consideration to the compliance margin achieved during the test. EPA should provide more flexibility in how operating parameter limits are set for each source and should allow the relevant permitting authorities to approve of site-specific alternatives.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Ahmed Idriss, Capital Power Corporation
Commenter Affiliation: CPI USA North Carolina (CPI NC)
Document Control Number: EPA-HQ-OAR-2002-0058-3524-A1
Comment Excerpt Number: 9

Comment: CPI NC does not support the EPA's proposal that minimum operating parameters be based on load. The proposed load-based minimum operating parameters do not make sense for facilities which are capable of operating at the same load utilizing different fuel mixes. The Facilities could encounter a situation where, load-based operating parameters, including sorbent injection rates, would be quite costly and because of the fuel mix would have no effect on reducing emissions. CPI NC recommends that EPA consider allowing facilities with multi-fuel units to adjust operating parameters, including sorbent injection rates, either based on load or fuel pollutant content of the fuel mix being fired, as appropriate.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1
Comment Excerpt Number: 100

Comment: Section 63.7515(f) requires monthly fuel analysis if a facility is complying with numeric emission limits using fuel analysis rather than stack testing:

"If you demonstrate compliance with the mercury, hydrogen chloride, or total selected metals based on fuel analysis, you must conduct a monthly fuel analysis according to § 63.7521 for each type of fuel burned that is subject to an emission limit in Table 1 or 2 to this subpart."

Some facilities may burn certain fuels subject to numeric emission standards only part of the year, and burn natural gas at other times. These facilities should not have to conduct monthly fuel analysis if they have not received additional fuel shipments since the last fuel analysis was performed.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1
Comment Excerpt Number: 101

Comment: The proposed rule requires development of operating parameter limits (OPLs) based on the values achieved during the performance test. In many cases, these levels will be appropriate only for certain modes of operation. For example, the absolute sorbent injection rate observed during the performance test conducted under full load and using the worst case fuel mix will not correlate to the sorbent injection rate necessary during startup or periods of lower load. Frequently, sorbent injection rates are set using a feedback loop from a CEMS or CPMS to

avoid wasting sorbent. EPA has acknowledged that the sorbent injection rate will vary with load in Table 7, which allows sources to adjust the sorbent injection rate by a load fraction. However, as EPA requires sources to test at the worst case fuel mix for chloride and mercury and this fuel mix may differ from the typical day to day fuel mix, EPA should also allow adjustments to sorbent injection rates based on fuel mix. For example, if a boiler is capable of burning both coal and biomass and tested at 100% coal firing for the mercury performance test, the carbon injection rate for periods of normal operation should not only be adjusted based on load but also by the percentage of coal being fired. If a boiler is burning natural gas or other clean fuel during a certain operational period, sorbent injection is not necessary.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 102

Comment: In Table 7, EPA only allows for operating parameter limit variation due to boiler/process heater load fraction to be applied to sorbent and activated carbon injection rates. However, variations with load and other operating conditions also occur for the other operating parameters- wet scrubber pressure drop, pH, and liquid flow rate, ESP voltage and secondary amperage. Flue gas flow rate and characteristics vary over load and with other operating variables such as fuel quality, to the extent that the single hourly average value determined during the high load steady state performance test will not apply to other conditions if overall performance is optimized. EPA should provide an allowance for any operating parameters to vary with unit load fraction as applicable to the operating parameter and specific affected source, and recognize that those operating parameters do not necessarily vary in a linear relationship with load, e.g., pressure drop typically varies with the (flow).

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: J. Michael Geers

Commenter Affiliation: Duke Energy

Document Control Number: EPA-HQ-OAR-2002-0058-3543-A1

Comment Excerpt Number: 9

Comment: In order to monitor the effectiveness of the control technologies installed on Industrial Boilers, the re-proposed rule requires sources to set operating limits on control technologies such as flue gas desulfurization (FGD), fabric filters, electrostatic precipitators, and dry sorbent injection (DSI) operations. Duke Energy has reviewed the proposal and in general has found that many of these operating limits do not accurately describe the performance of emission control technologies, nor do they ensure proper removal of the HAPs. If a boiler were to in some way deviate from one or more of these operational limits, even though emissions standards are still being met, that unit would be considered to be in non-compliance, and enforcement actions could be taken.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: J. Michael Geers

Commenter Affiliation: Duke Energy

Document Control Number: EPA-HQ-OAR-2002-0058-3543-A1

Comment Excerpt Number: 10

Comment: The performance tests used to set the proposed operating limits are done infrequently, and at full operating load. While these tests might represent the worst-case conditions, they are not representative of all conditions. In addition, the proposed operating limits constrain lowerload operation to the conditions met at the full-load test conditions which is counterproductive or not even possible to meet. As EPA has previously recognized in the context of the NSPS and the CAM rule, “many sources operate well within permitted limits over a range of process and pollution control device operating parameters,” and requiring sources to continuously maintain parameters that “happened to exist” during the most recent performance test “may not be possible or wise.”² This is because control device parameters, such as those identified by EPA for scrubbers and ESPs, do not necessarily have a direct relationship to emissions removed, but instead are interrelated with the design of the control device and the interaction of various parameters. As a result, a single parameter may vary widely with little effect on emissions.

[Footnote]

(2) See Fed. Reg. 62 Fed. Reg. 54,907, 54,926-27.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: J. Michael Geers

Commenter Affiliation: Duke Energy

Document Control Number: EPA-HQ-OAR-2002-0058-3543-A1

Comment Excerpt Number: 11

Comment: Establishing emission limits based on specific operating parameters by default makes the devices measuring the operation such as pH monitors, flow meters, pressure transmitters, ESP voltage controllers, and others, equivalent to opacity monitors, which themselves are surrogates for stack PM emissions. In addition, EPA has failed to provide the requisite quality control and certification procedures for these new measurement devices. Maintaining instrumentation to the level of emission control monitoring equipment is a tremendous cost burden for boiler operators; especially when the operating conditions change day-by-day with varying load demands and coal quality.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: J. Michael Geers
Commenter Affiliation: Duke Energy
Document Control Number: EPA-HQ-OAR-2002-0058-3543-A1
Comment Excerpt Number: 12

Comment: Because of the diversity of control equipment and the site-specific nature of its operation, Duke Energy recommends that EPA require site-specific plans where all industrial boiler operators would develop their own series of operating limits and allow state and local agencies to review these plans.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: J. Michael Geers
Commenter Affiliation: Duke Energy
Document Control Number: EPA-HQ-OAR-2002-0058-3543-A1
Comment Excerpt Number: 13

Comment: Restricting pH is not Necessary to Ensure Effective Removal of HCl and Other Acid Gases The proposed IB MACT rule requires units using FGD systems to demonstrate compliance with the HCl and HF removal by measuring pH during the performance tests, and by maintaining 30 day average pH readings above the level of those collected in the test. This pH measurement is not sufficiently related to acid gas removal to apply enforceable limits. The measurement of pH in an FGD system is only a small part of the very complex chemistry in an SO₂ removal system; the pH is mainly used to prevent scaling of the modules. Maintaining a higher pH does not guarantee any additional removal of SO₂, HCl, or other acid gases. Higher pH values will, however, lead to scaling, which may lead to other operational problems. As an example, scaling can cause plugging of mist eliminators, which in turn could potentially increase particulate emissions.

Acid gases such as HCl and HF are strong acids and very readily dissolve in water. By comparison SO₂ is a weak acid which explains why its transport from the gas phase into the liquid phase in a scrubber occurs at a slower rate. EPA recognizes this relationship in the proposed the Utility MACT standard when it stated.

Acid gases are likely to be removed in typical FGD systems due to their solubility or their acidity (or both). The acid-gas HAP—HCl, HF, and HCN (representing the “cyanide compounds”)—are water-soluble compounds, more soluble in water than is SO₂. This indicates that HCl, HF, and HCN should be more easily removed from a flue gas stream in a typical FGD system than will SO₂, even when only plain water is used. Hydrogen chloride is also a strong acid and will react easily in acid-base reactions with the caustic sorbents (e.g., lime, limestone) that are commonly used in FGD systems.³

These same chemical relationships apply to the FGD systems used for industrial boilers. The conclusion is that HCl and other acid gases are very effectively removed by contact with water in a wet FGD system, so effectively removed in fact that high removal rates will be maintained even at pH levels below those used for effective SO₂ removal, provided there is an adequate

recirculation flow. Instead of requiring FGDs to maintain a specified pH, the rule should require that operators develop site specific plans that incorporate parameters that more appropriately describe the operation of an FGD system. Operators may elect to use parameters such as number of absorber recirculation pumps in service, measured SO₂ levels from CEMS measurements, or other facility specific measurements.

[Footnote]

(3) See 76 Fed. Reg. 25,014.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: J. Michael Geers

Commenter Affiliation: Duke Energy

Document Control Number: EPA-HQ-OAR-2002-0058-3543-A1

Comment Excerpt Number: 14

Comment: Operating Limits For Maintaining Minimum Wet FGD Liquid Flow Rate At Values Established During the Performance Test Are Highly Problematic In its proposal, EPA establishes a requirement that boilers utilizing wet FGD systems must establish minimum values during the performance test for liquid flow rate. As a first point, there is ambiguity in what EPA wants to restrict. There are two potential liquid flows in an FGD system. The first is the amount of chemical reagent that is added to the FGD module. This is most commonly either a water slurry of lime or limestone.

The concentration of this material varies depending upon the operating conditions. The mass flow rate of reagent is directly proportional to the mass of sulfur dioxide that is removed in the scrubber per unit of time. Because the chemical reagent must be added at the proper stoichiometric ratio, it is totally inappropriate to require a fixed feed ratio based on full load, worst-case conditions. Doing so will damage the FGD system and will render it ineffective for removing sulfur dioxide and other acid gases. As a result Duke Energy concludes that EPA is not attempting to regulate lime or limestone reagent flow, but instead seeks to regulate the total amount of liquid flow that is recirculated in the module and sprayed into the flue gas stream. For purposes of these comments, Duke Energy defines this as FGD recirculation flow. FGD modules use one or more recirculation pumps to remove large volumes of FGD liquor from a reservoir in the bottom of the module and spray it into the flue gas. These are high volume, centrifugal pumps that run at a single speed. Most sources do not 4 See 76 Fed. Reg. 80,664, Table 4. normally install flow meters in this situation, and installing monitors in this application will not achieve the accuracy that EPA specifies. Most new FGD installations utilize fiberglass reinforced piping (FRP) to transport recirculation flow through the FGD module. The FRP increases reliability, but is not conducive to external flow measurement techniques. Further complicating the matter is size of the piping—the larger the diameter, the more difficult to obtain accurate readings. Flow meters with the proposed accuracy of 2% are not practical for these FGD installations. In addition, while internal flow meters may be able to provide reasonably accurate readings immediately after installation, the harsh conditions of the FGD will cause their accuracy to quickly degrade. Also, the length of FGD piping is short compared to its diameter, and has

many elbows and fittings, so there typically are not enough straight lengths of pipe to allow for the installation of highly accurate flow monitors. Even if the recirculation flow rate could be measured to the desired accuracy, those measurements would not tell the whole story. In a properly operating FGD system, the density of the recirculation flow has to change with different operating conditions to maximize removal efficiency. When the density of a material being pumped increases, the volume of flow through a centrifugal pump decreases. FGD operators do not have control over this recirculation flow because the piping systems do not have any sort of flow control valves. In short, a recirculation pump is either on or off. Therefore, attempting to maintain volumetric flow rates at a level established during the performance test would force operators to chase process parameters that would be counterproductive to achieving the best removal efficiency. Finally, EPA should also realize that when a boiler reduces its load, the volume of flue gas passing through the FGD system decreases, while the amount of recirculation flow stays relatively constant. This results in an increase in the liquid to gas ratio, which in turn promotes even more efficient scrubbing. Therefore the more appropriate operating parameter would be to require that boilers be required to maintain a minimum recirculation flow to gas ratio instead of a simple minimum liquid flow rate. That would best be accomplished by requiring a minimum number of pumps to be kept in service at all times as demonstrated during the performance test. As a result, flow monitors would not be needed. It would also be appropriate for EPA to require sources to demonstrate that the flue gas is indeed going through the scrubber module and is not being bypassed. These operating parameters will adequately ensure that the FGD operation will properly remove the acid gases that will be regulated in the final rule. Duke Energy recommends that EPA make these changes in the final rule.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: J. Michael Geers

Commenter Affiliation: Duke Energy

Document Control Number: EPA-HQ-OAR-2002-0058-3543-A1

Comment Excerpt Number: 15

Comment: Restricting Wet PM Scrubbers a Minimum Pressure Drop Requirement Has No Benefit, But Will Force Sources into Non-Compliance EPA proposes to set a minimum pressure drop limitation on wet scrubber systems to ensure proper particulate and acid gas capture. In the proposed rule, boilers would be required to measure differential pressure across the scrubber during the annual performance tests, and maintain a 30-day rolling pressure drop value above the average measured in the performance test. As with other limits EPA has proposed, this limit fails to account for reduced load operation. Pressure drop is a direct function of the amount of flue gas flow through the module, and thus is directly related to boiler load. A basic engineering principle is that the pressure drop through a restriction, such as a PM scrubber vessel, is directly related to the square of the velocity. In a case where velocity doubles, the pressure drop would quadruple. The reverse is also true, in that as the load drops, the scrubber pressure drop would also decrease. There are different types of scrubber systems such as open spray towers, and units with trays; however for all these designs, a reduced pressure drop at lower load does not by itself indicate a reduced level of PM capture. In fact, the performance is more likely to improve at reduced load because there is a higher ratio of liquid flow to flue gas flow.

Boilers constantly operate at many different load conditions, which causes changes in flue gas flow. While Duke Energy has no direct experience, there may be sources, such as hazardous waste combustors, where measuring pressure drop in a scrubber could be more useful. These systems could have a stable pressure drop if they were operated at a steady state with a constant gas flow, and without the load swings typical of an industrial boiler. Unfortunately EPA has proposed this operating limit in such a way that simply reducing load will put a source in a condition of non-compliance, even though scrubber performance is more likely to improve at reduced load. In addition to the lack of correlation with removal, pressure drop across a module can be very difficult to measure consistently, because of its low value. EPA makes the point that sources could elect to test at different loads; however, that is not a feasible option, because properly characterizing a unit's performance would require tests at many load points. Instead of using pressure drop to demonstrate compliance, EPA should require operators to develop site-specific plans to ensure the effectiveness of the FGD for particulate removal and acid gas removal. Those plans would then be subject to review by state and local agencies. These plans would contain more appropriate requirements such as maintaining a minimum number of recirculation pumps in service, eliminating any bypasses of the system, and periodically inspecting internal components.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: J. Michael Geers

Commenter Affiliation: Duke Energy

Document Control Number: EPA-HQ-OAR-2002-0058-3543-A1

Comment Excerpt Number: 16

Comment: Operating Limits For Sorbent Injection Should Be Revised. The proposed IB MACT rule requires boilers that use dry sorbent injection (DSI) for acid gas control and/or activated carbon injection (ACI) for mercury control to measure the feed rate of reactant, and maintain operational feed rates above the level established during the performance test. There are multiple problems with this proposed requirement. Both DSI and ACI feed rates are normally correlated with other plant conditions, such as unit load or flue gas flow, making a single fixed feed rate inappropriate. As an example, sorbent rates are normally set as a mass flow per volume of flue gas, such as a pound of sorbent per hundred thousand cubic feet of flue gas. As a result, half the amount of sorbent would be injected when the flue gas flow is reduced by half. In addition to the problem of using one minimum flow rate for all conditions, the ability to measure the sorbent has problems. The material handling equipment for a dry solid such as Trona, ACI or other materials whether milled or not, is not capable of precise weight measurements. Load cells are typically used to gather injection rates, but because the material can clump or surge, short term measurements such as a fifteen minute interval are too small to average out all the fluctuations. Finally, DSI injection rates are closely linked with ESP performance. Injecting a "minimum" amount of sorbent over the entire operating range of a unit could change the ash resistivity and thus impact precipitator performance, potentially making it impossible to be in compliance with the operating limits for both sorbent injection rate and ESP total secondary electric power.

To account for these issues, EPA should allow sources to use for the “load fraction” parameters such as steam flow, flue gas flow, or if applicable, electric load. These rates would then be monitored over a 30 day average.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: J. Michael Geers

Commenter Affiliation: Duke Energy

Document Control Number: EPA-HQ-OAR-2002-0058-3543-A1

Comment Excerpt Number: 17

Comment: Operating Limits on ESP Total Secondary Electric Power Is Not a Reliable Measure of Compliance

Electrostatic precipitators are utilized by boilers for PM removal. The proposed rule puts limits on total secondary power to the ESP, requiring EGUs to maintain power levels above those measured during the annual performance test. This power level approach for ESPs does not work and this fact is easily demonstrated by real world operating experience. Precipitator power will vary depending upon a number of factors, including operating conditions, coal quality, load, and other factors. This is a phenomenon that Duke Energy routinely sees in the operation of its own units. Precipitator operation is complicated even further with the addition of sorbents into the flue gas for emissions control. Different fuels may require more or less DSI, and those fuels will also cause changes in precipitator operation. These changes will likely result in a change in the total secondary power to the ESP, but not necessarily a reduction in removal efficiency. The EPA should instead require site-specific plans to be developed for each affected industrial boiler. Because ESP designs vary greatly, the parameters selected may include total percent of fields in service, or a limit on the number of fields in a given train that may be out of service at one time.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Robin Mills Ridgway

Commenter Affiliation: Purdue University

Document Control Number: EPA-HQ-OAR-2002-0058-3668-A2

Comment Excerpt Number: 15

Comment: For units using dry sorbent injection (e.g., CFBs), the proposal mandates that the sorbent injection rate at that time of the HCl performance test is to be the minimum rate scaled for load across the load range of the boiler. Actual operational data analysis (at Purdue’s Boiler #5, a 279 MMBTU/hr CFB burning bituminous coal; see DCN_____) indicates that the relationship between limestone injection rate and load is not linear. In fact, application of EPA’s proposed methodology would actually inhibit the operation of the unit at low loads by interfering with the very fundamental design parameter of coal fired CFBs with limestone co-firing design: the calcium to sulfur ratio of the fuel and the sorbent. In addition, overfeeding limestone in a CFB furnace inhibits the solids recirculation and heat transfer that are other fundamental design parameter of CFBs.

Because ensuring on an ongoing basis that sorbent injection is at least the minimum dictated by linearized extrapolation is unworkable, Purdue requests that EPA consider other monitoring methodologies. For example, because the coal to limestone ratio in a CFB is tuned on a real time basis to account for the sulfur content of the fuel and ensure that the correct amount of limestone is fed as well as comply with the 90% reduction requirement of NSPS, the sulfur content of the fuel Ca/S ratio is maintained through boiler tuning and controls at an optimum ratio. The ratio is not only dependent upon the actual calcium content of the limestone, but also the reactivity of the limestone and the boiler bed temperature which influences the necessary "first step" calcining reaction of the limestone. The bed temperature and reactivity of the limestone are relatively constant; however the sulfur content of the fuel can vary.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 104

Comment: Sorbent injection rate operating limits for HCl and Hg control should be allowed to be adjusted for operating rates higher than the performance test operating rate as well as being adjusted for lower rate operation.

For BPH with sorbent injection, you must measure the sorbent injection rate for each acid gas sorbent used during the performance tests for HCl and for activated carbon for Hg and calculate the hourly average for each sorbent injection rate during each test run. The lowest hourly average measured during the performance tests becomes your site specific minimum sorbent injection rate operating limit. When your unit operates at lower loads, you must multiply your sorbent injection rate from the performance test by the load fraction (operating heat input divided by the average heat input during your last compliance test for the appropriate pollutant) to determine the required injection rate operating limit value.

While performance tests are performed at high operating rates, they are not necessarily carried out at the highest operating rate achievable. Since HCl and Hg emissions are a function of fuel composition, not combustion, there is no reason the operating limit should not be adjusted for higher operating rates than during the performance test, just as it is required to be adjusted for lower operating rates and we therefore recommend such an adjustment be allowed.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Douglas A. McWilliams

Commenter Affiliation: American Municipal Power

Document Control Number: EPA-HQ-OAR-2002-0058-3685-A2

Comment Excerpt Number: 40

Comment: Subsequent Performance Tests Should Not Automatically Reset Operating limits

If operating limits remain in the final rule, EPA must clarify the procedures used to establish them. As currently written, § 63.7520 is ambiguous as to whether sources will automatically reset their operating limits each time they conduct a performance test. This provision should clarify that sources have the *option* of resetting their operating limits following each subsequent performance test, but they are not required to do so. Operating limits are established during performance tests because, in EPA's view, these limits represent an operating mode in which the source is known to be in compliance with its emission limits. If a source has demonstrated compliance at a particular operating limit, the source is presumptively in compliance with its emission limit so long as it maintains compliance with that operating limit. Sources should therefore have the flexibility to demonstrate continuous compliance by complying with any operating limit that has been demonstrated through a stack test to be indicative of compliance.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: M.L. Steele

Commenter Affiliation: CraftMaster Manufacturing, Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3814-A1

Comment Excerpt Number: 17

Comment: §63.7530 Site specific operating limits for Hg, HCl, and TSM input levels from fuels. The proposed rules require performance testing while firing the fuels with the maximum pollutant (Hg, HCl, and TSM) input and establishing operating limits to maintain the pollutant input at or below the levels during the performance test. Compliance is determined by fuel analyses.

CraftMaster requests some latitude here because of the variable nature of its woody biomass fuels. Pollutant levels can vary due to the soil conditions in the area where the biomass is harvested. Also the amount of soil (and pollutants) in the biomass varies with weather conditions. These factors are obviously beyond our control.

It is requested that the fraction of pollutant input from fuels that is actually emitted be determined during performance testing. Then that fraction along with the applicable limit could be used to establish the site-specific operating limit.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Startup, Shutdown, and Malfunction (SSM)

12A. Startup/Shutdown: Rationale for Work Practices

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 47

Comment: EPA requests comment on the rationale for setting work practice standards for periods of startup and shutdown. EPA has not provided any showing that it is infeasible to set an emission standard during this period. Although the agency claims that it would be difficult to conduct emission testing during startup and shutdown periods, that claim does not establish that it is actually infeasible to measure emissions during such periods, merely that EPA has not done so and believes it would be difficult. Moreover, EPA already relies on measures other than stack testing, such as CEMs or parameter monitoring, to evaluate compliance with emission standards during the vast majority of sources operations. EPA provides no reason why these same measures could not be used to determine compliance during startup and shutdown regardless of whether stack testing can occur during such times. Moreover, the agency proposes to measure compliance with 30-day rolling averages. EPA provides no reason that sources cannot comply with emission standards at all times – especially if their emissions are measured on a 30-day rolling average basis – regardless of whether they are stack tested or can be stack tested during periods of startup and shutdown.

Response: Consistent with *Sierra Club v. EPA*, EPA has established standards in this final rule that apply at all times. In establishing the standards in this final rule, EPA has taken into account startup and shutdown periods and has established different standards (i.e., work practice standards) for those periods. EPA also found no evidence that suggested that emissions were higher during startup or shutdown that would indicate a need for an alternate emission standard for these periods and commenters provided no data or basis to show that sources cannot comply with the standards as proposed. Thus we set standards based on available information as contemplated by section 112.

Compliance with the numeric emission limits (i.e., PM or TSM, HCl, mercury, and CO) are demonstrated by conducting performance stack tests, not on a 30-day rolling average basis. It was determined that it was not feasible to prescribe or enforce an emission standard during startup and shutdown due to technological and economic limitations. Thus, as allowed under section 112(h) of the Clean Air Act, a work practice standard was incorporated for periods of startup and shutdown in the March 2011 final rule. The rationale for justifying work practice standards for periods of startup and shutdown is described in the preamble to the March 2011 final rule. See 76 FR 15642. Additionally, of the emission data submitted in response to the ICR, there were no HAP data for startup and shutdown periods because of the limitations in conducting stack tests during these periods. Thus, we do not have data on emissions that occur during startup and shutdown on which to set emission standards. We therefore established work practice standards rather than numeric emissions standards for periods of startup and shutdown in the March 2011 final rule. The EPA has considered this and other comments and is maintaining the work practice standard for periods of startup and shutdown. Information provided on the amount of time required for startup and shutdown of boilers and process heaters indicates that the application of measurement methodology for these sources using the required procedures, which would require more than 12 continuous hours in startup or shutdown mode to satisfy all of the sample volume requirements in the rule, is impracticable. In addition, the test methods are required to be conducted under isokinetic conditions (i.e., steady-state conditions in terms of exhaust gas temperature, moisture, flow rate) which is difficult to achieve during these

periods where conditions are constantly changing. Upon review of this information, the EPA determined that it is not feasible to require stack testing—in particular, to complete the multiple required test runs—during periods of startup and shutdown due to physical limitations and the short duration of startup and shutdown periods. Operating in startup and shutdown mode for sufficient time to conduct the required test runs could result in higher emissions than would otherwise occur. Based on these specific facts for the boilers and process heater source category, EPA developed a separate standard for these periods, and we are finalizing amendments to the work practice standards to meet this requirement. The work practice standard requires sources: (1) to operate all continuous monitoring systems during startup and shutdown, (2) must use one or a combination of the listed clean fuels, (3) once start firing coal/solid fossil fuel, heavy liquid fuel, or Gas 2 (other) gases must engage all of the applicable control technologies except dry scrubber, fabric filter, SNCR, and SCR during periods of startup and shutdown, (4) to start dry scrubber, fabric filter, SNCR, and SCR systems, if present, appropriately to comply with relevant standards applicable during normal operation, (5) to comply with all applicable emissions and operating limits at all times the unit is in operation except for periods that meet the definitions of startup and shutdown, and (6) to keep records concerning activities (e.g., type and amount of fuel used) and periods (e.g., date and duration of each) of startup or shutdown.

EPA has revised the proposed definitions of “startup” and “shutdown” to separate periods of startup and shutdown from periods of normal operation based on supply of steam under proper conditions instead of specific load conditions (i.e., 25 percent load). We are finalizing definitions of “startup” and “shutdown” as follows:

Startup means either the first-ever firing of fuel in a boiler or process heater for the purpose of supplying steam or heat for heating and/or producing electricity, or for any other purpose, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam or heat from the boiler or process heater is supplied for heating and/or producing electricity, or for any other purpose.

Shutdown means the cessation of operation of a boiler for any purpose. Shutdown begins either when none of the steam or heat from the boiler or process heater is supplied for heating and/or producing electricity, or for any other purpose, or at the point of no fuel being fired in the boiler, whichever is earlier. Shutdown ends when there is both no steam or heat being supplied and no fuel being fired in the boiler.

Commenter Name: Melvin E. Keener

Commenter Affiliation: Coalition for Responsible Waste Incineration (CRWI)

Document Control Number: EPA-HQ-OAR-2002-0058-3454-A1

Comment Excerpt Number: 7

Comment: EPA also asks for comments on using work practices during startup and shutdown (76 Fed. Reg. at 80615). CRWI and many other commenters suggested the use of work practices in our comments on the 2010 proposed rule (75 Fed. Reg. 32006, June 4, 2010) (CRWI’s comments are at EPA-HQ-OAR-2002-0058-2824). In those comments we pointed out that it is difficult to use stack testing methods to obtain emissions estimates during transient conditions. Even if data could be obtained during rapidly changing conditions (e.g., use of CEMs), it is difficult to understand what that data means or how it can be used to determine top performers.

However, Congress provided for these types of conditions when they set up the work practice provisions of 112(h). Here Congress stated that EPA may set work practice standards if it is not feasible to prescribe or enforce an emissions standard. CRWI continues to believe that it is infeasible to gather data during startup and shutdowns simply because there are no EPA approved methods to make measurement during non-steady-state. As such, CRWI believes that EPA has properly used work practice standards for startup and shutdown periods.

Response: The EPA thanks the commenter for their support.

Commenter Name: Allison Watkins, Baker Botts

Commenter Affiliation: Class of '85 Regulatory Response Group

Document Control Number: EPA-HQ-OAR-2002-0058-3608-A1

Comment Excerpt Number: 1

Comment: The Class of '85 supports the use of work practice standards during startup and shutdown. It is not technically feasible to conduct stack testing during periods of startup and shutdown because of physical limitations and the short duration of startup and shutdown periods. EPA is correct that operating in startup and shutdown mode for sufficient time to conduct test runs to demonstrate compliance with a stack testing requirement could result in higher emissions than would otherwise occur.

Response: The EPA thanks the commenter for their support.

Commenter Name: Randal G. Oswald

Commenter Affiliation: Integrys Energy Group

Document Control Number: EPA-HQ-OAR-2002-0058-3659-A2

Comment Excerpt Number: 1

Comment: Integrys supports the use of work practice standards during startup and shutdown. It is not technically feasible to conduct stack testing during periods of startup and shutdown because of physical limitations and the short duration of startup and shutdown periods. EPA is correct that operating in startup and shutdown mode for sufficient time to conduct test runs to demonstrate compliance with a stack testing requirement could result in higher emissions than would otherwise occur.

Response: The EPA thanks the commenter for their support.

Commenter Name: Richard D. Garber

Commenter Affiliation: Boise Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3686-A2

Comment Excerpt Number: 2

Comment: Recognition of limited data availability for startup and shutdown periods for biomass boilers and the appropriateness of applying work practices during these periods. Use of work practices for startup and shutdown periods was very much in need and helps to make the standard more implementable from a practical, on-the-ground standpoint.

Response: The EPA thanks the commenter for their support.

Commenter Name: Randall D. Quintrell

Commenter Affiliation: Georgia Paper & Forest Products Association

Document Control Number: EPA-HQ-OAR-2002-0058-3451-A1

Comment Excerpt Number: 16

Comment: The implementation of work practice standards for periods of startup and shutdown also is a necessary and appropriate measure, recognizing that these emissions have not been included in the steady-state floor analysis and that they cannot be measured accurately and reliably to establish a separate numerical standard. To consider these periods in any other fashion, e.g., against the steady-state emissions limits, would require including the typically higher emissions during such periods in the continuous limits, and thus would necessarily increase those limits significantly.

Response: The EPA thanks the commenter for their support.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 110

Comment: Section 112(h) allows EPA to set work practice standards for situations where it is not feasible to prescribe or enforce an emission standard. Gathering data for pollutant emissions from startup and shutdown periods would be nearly impossible given the brief nature of these periods, as well as the need to define the exact time period for what is considered “startup” and/or “shutdown,” and the fact that most reference methods are not designed for non-steady state conditions and would not perform well during these periods. Moreover, the definition of “not feasible to prescribe or enforce an emission standard” is defined in §112(h) as any situation where “the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations. Startup, shutdown, and malfunction events fit perfectly within this definition for the reasons outlined above and justify establishing work practices to address emissions during these periods. Furthermore, a work practice approach for these periods would be in keeping with the statute’s requirement that MACT standards be “achievable” as well as with the underlying requirement that a standard apply at all times.

Response: The EPA thanks the commenter for their support.

Commenter Name: J. Michael Geers

Commenter Affiliation: Duke Energy

Document Control Number: EPA-HQ-OAR-2002-0058-3543-A1

Comment Excerpt Number: 6

Comment: In the IB MACT proposed rule, EPA is proposing revised work practice standards for periods of startup and shutdown that will make some very necessary improvements.

Duke Energy strongly supports this definition for several reasons. First and foremost, it well encompasses the actual transient period that operators face when starting and shutting down a unit. During this period the unit and its emissions control devices are not and cannot function at the same level of performance as normal operating conditions outside the start-up and shutdown period. Emissions are different in these ranges, and there is not sufficient data to set a different standard during these periods. In addition because start-up and shutdown are by their nature very transient periods, it is not feasible to get the data necessary to set such a standard.

Given these conditions and the amount of data available, it is most appropriate to set work practice standards instead of actual emissions limits.

Response: The EPA thanks the commenter for their support.

Commenter Name: Dakota Gasification Company Great Plains Synfuels Plant

Commenter Affiliation: David W. Peightal

Document Control Number: EPA-HQ-OAR-2002-0058-3424

Comment Excerpt Number: 13

Comment: DGC agrees with EPA on the work practice standard during SSM events and that the emissions generated would not be subject to the numeric emission limits.

Response: The EPA thanks the commenter for their support.

Commenter Name: Lee Zeugin and Lauren Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1

Comment Excerpt Number: 23

Comment: UARG supports the setting of work practice standards during periods of startup and shutdown. IB units are started up and shut down in a wide variety of ways. Some boilers may start up on fuels that they do not burn during normal operations. Different control equipment can be brought online at different stages of a unit's startup. The duration of startups can also vary significantly. Given the uncertainties about the magnitude and duration of HAP emissions during startup and shutdown, the promulgation of work practice standards for IB units is justified.

Response: The EPA thanks the commenter for their support.

Commenter Name: James Johnson

Commenter Affiliation: United States Beet Sugar Association (USBSA)

Document Control Number: EPA-HQ-OAR-2002-0058-3508-A1

Comment Excerpt Number: 7

Comment: The USBSA commends the EPA for altering the proposed Boiler MACT rules in the reconsideration to allow for work practices standards during startup and shutdown,¹⁶ as well as for the control of dioxins and furans. Work practices standards, as allowed under section 112(h) of the CAA, maintain strong environmental protection while also including needed flexibility. Work practices can be utilized by the agency "if it is not feasible in the judgment of the

Administrator to prescribe or enforce an emission standard for control of a hazardous air pollutant or pollutants.”¹⁷

[Footnotes]

(16) Work practices for startup and shutdown for the major source Boiler Rule, 76 Fed. Reg. at 80,615.

(17) Clean Air Act, § 112(h); 42 U.S.C. § 7412(h).

Response: The EPA thanks the commenter for their support.

Commenter Name: Alicia Meads

Commenter Affiliation: National Association of Manufacturers (NAM)

Document Control Number: EPA-HQ-OAR-2002-0058-3515-A1

Comment Excerpt Number: 6

Comment: The NAM agrees with the EPA’s rationale for justifying work practice standards for periods of startup and shutdown, as described in the preamble to the final rule. 76 Fed. Reg. 15,642. The EPA’s rationale, along with the concerns raised in prior comments by the NAM and others, justify reliance on work practices.

Response: The EPA thanks the commenter for their support.

Commenter Name: Stephen E. Woock

Commenter Affiliation: Weyerhaeuser Company

Document Control Number: EPA-HQ-OAR-2002-0058-3523-A1

Comment Excerpt Number: 2

Comment: We support EPA’s decision in the March 2011 final rules to set work practices for startup and shutdown events rather than the erroneous 2010 proposed rule assumption that emission limits set for full operating periods reflected and could legally apply as well during these events.

Response: The EPA thanks the commenter for their support.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 44

Comment: In the Final Boiler MACT Rule, EPA finalized work practice standards for periods of startup and shutdown. 76 Fed. Reg. 80,602. As stated in our comments on the Final Boiler MACT Rule, EPA has the authority to authorize work practices. Furthermore, as EPA indicated in the preamble to the Final Boiler MACT Rule, work practices are appropriate standards for periods of startup and shutdown. See 76 Fed. Reg. 15,642.

Response: The EPA thanks the commenter for their support.

Commenter Name: Annabeth Reitter
Commenter Affiliation: NewPage Corporation
Document Control Number: EPA-HQ-OAR-2002-0058-3662-A2
Comment Excerpt Number: 9

Comment: In the Boiler MACT reconsideration proposal, EPA is proposing to define startup and shutdown periods and the use of work practice standards during periods of startup and shutdown. New Page supports the use of work practices for startup and shutdown.

Response: The EPA thanks the commenter for their support.

Commenter Name: Lorraine Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1
Comment Excerpt Number: 108

Comment: WORK PRACTICES DURING STARTUP AND SHUTDOWN

ACC provided extensive support for establishing work practices for periods of startup and shutdown in our comments on the 2010 Proposed Boiler Rule.³⁴ Our key points supporting work practices for startup and shutdown periods were:

The statute requires that the standards established under §112(d)(2) be "achievable." Sources cannot achieve the proposed numeric standards during periods of startup and shutdown in many cases.

The D.C. Circuit also has recognized that standards based on what sources achieve must account for the limitations inherent in the technology used to reduce emissions. Certain air pollution control equipment (e.g., fabric filters and ESPs) cannot fully operate until certain boiler operating conditions are reached (e.g., appropriate stack gas temperature).

EPA did not use any data obtained during periods of startup and shutdown in setting stack test-based standards.

Sources cannot meet CO standards during low load and transient load periods.

Safety concerns must be accommodated during startup and shutdown.

Other recent MACT rules, such as the RICE MACT, incorporate work practices for startup and shutdown.

[Footnote 34: See Docket ID EPA-HQ-OAR-2002-0058-2792.]

Response: The EPA thanks the commenter for their support.

Commenter Name: Susan J. Miller
Commenter Affiliation: Brick Industry Association (BIA)

Document Control Number: EPA-HQ-OAR-2002-0058-3530-A1

Comment Excerpt Number: 3

Comment: EPA properly concluded that a work practice approach must be applied during startup and shutdown periods. There are many reasons why this approach is justified, including the fact that no data from startup and shutdown periods were used to set any stack test-based emission limits. In addition, safety and good operational practices, including preservation of the integrity of control devices, must be of prime concern during startup and shutdown. A work practice approach is the best approach for periods of startup and shutdown emissions in most industries as opposed to the approach used by EPA in other rules. It is not reasonable to assume that the emissions during start-up and shutdown are represented by the emissions during a relatively short (e.g., 3 hour) stack test. Unless reliable data exists to the contrary, EPA should use the work practice approach in all rules.

Response: The EPA thanks the commenter for their support.

Commenter Name: Traylor Champion

Commenter Affiliation: Georgia-Pacific LLC (GP)

Document Control Number: EPA-HQ-OAR-2002-0058-3465-A1

Comment Excerpt Number: 4

Comment: GP supports EPA's position to include a work practice standard under Section 112(h) of the CAA for periods of startup and shutdown. EPA has proposed specific requirements such as ensuring that good combustion practices are maintained by monitoring O2 levels and optimizing the equipment per manufacturer recommendations, training operators on startup and shutdown procedures, and maintaining records during the startup and shutdown periods. EPA is justified in establishing work practice standards due to the limited periods these events occur; establishing numeric emissions limit is impractical due to unstable unit operations and combustion during this operating mode.

Response: The EPA thanks the commenter for their support.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 111

Comment: EPA has proposed to expand upon the work practice requirements in the Final Boiler Rule by adding specific requirements to employ good combustion practices, train operators on proper startup and shutdown procedures, and maintain records (see Table 3 item 5 of the reconsidered rule). ACC agrees that these are appropriate requirements.

Response: The EPA thanks the commenter for their support.

Commenter Name: Steve Gossett

Commenter Affiliation: Eastman Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3669-A2

Comment Excerpt Number: 31

Comment: We agree that work practice standards are appropriate during startups and shutdowns. The proposed standards shown in Table 3, item 5 seem appropriate including operator training and procedures to minimize emissions.

Response: The EPA thanks the commenter for their support.

Commenter Name: Elizabeth McMeekin

Commenter Affiliation: PPG Industries, Inc

Document Control Number: EPA-HQ-OAR-2002-0058-3778-A1

Comment Excerpt Number: 14

Comment: PPG agrees that Defining Work Practices for Periods of Startup And Shutdown is Appropriate. EPA has proposed to expand upon the work practice requirements in the March 2011 rule by adding specific requirements to employ good combustion practices, train operators on proper startup and shutdown procedures, and maintain records (see Table 3 item 5 of the proposed rule). We agree that these are appropriate requirements.

Response: The EPA thanks the commenter for their support.

Commenter Name: Jessica Bridges

Commenter Affiliation: United States Clean Heat & Power Association (USCHPA)

Document Control Number: EPA-HQ-OAR-2002-0058-3501-A1

Comment Excerpt Number: 17

Comment: EPA provides an adequate rationale for utilizing work practices rather than emissions limits during startup and shutdown periods. It is appropriate to treat startup periods as upward to 25% load and shutdown periods from 25% load downward. The duration of such periods is significantly both load and technology dependent. At least with CHP systems, running at 25% or less load is generally relatively inefficient and therefore the operation will likely be set to move through this ramping relatively rapidly as long as load needs are met.

Response: The EPA thanks the commenter for their support. See the response to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46 and comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5 under the chapter SS - Elements of Work Practices regarding 25% load SS definition threshold.

Commenter Name: Barry Christensen

Commenter Affiliation: Occidental Chemical Corporation (OCC)

Document Control Number: EPA-HQ-OAR-2002-0058-3477-A1

Comment Excerpt Number: 11

Comment: OCC supports the clarification that emission limitations and operating limits do not apply during periods of startup or shutdown. However, further clarification of these provisions is needed with respect boilers that operate in standby mode.

Industrial boilers operate over a wide range of range of load conditions and must be highly reliable to avoid upsets resulting in the loss of production, damage to equipment and the associated expenses and loss of revenue. To address these risks, many operators maintain back-up boilers in standby mode with significantly reduce load demand. Some boilers in standby mode are stable at operating loads of less than 25%, while others may not be. Consequently, an allowance must be made clear in the final rule for boilers and process heaters that operate in standby mode at low firing rates for extended periods of time. The currently proposed definition of startup uses a cold startup example in the definition, but does not expressly exclude boilers operating in standby mode. Boilers operating in standby mode simply do not perform in the same manner as boilers sequencing through startups and shutdowns.

For example, in our PVC plants the sudden loss of steam from one of our boilers without having another in standby mode would have the following consequences: Higher emissions of volatile organic compounds from the slurry resin process because steam strippers are used to reduce emissions of residual vinyl chloride and other compounds from the PVC slurry produced in the reactors, The production of off-grade product which would also result from loss of these steam strippers. This off spec material would have to disposed of as a waste if a buyer is not available, Increased emissions from wastewater generated from the process which relies on a steam strippers to remove volatile organic compounds from process wastewater, and One of our plants supplies steam to an adjacent chemical plant where the loss of steam can cause at least one of their processes to vent to a flare with increased emissions.

Therefore, it is not practical or reasonable to impose the time limits and capacity minimums applicable to boiler startups and shutdowns on boilers in standby mode. However, good combustion practices can still be followed with standby boilers to minimize emissions.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 117 under the chapter SS - Elements of Work Practices regarding standby mode and startup/shutdown provisions. See the response to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46 under the chapter SS - Elements of Work Practices regarding 25% load SS definition threshold.

Commenter Name: Jennifer Youngblood

Commenter Affiliation: National Tribal Air Association

Document Control Number: EPA-HQ-OAR-2002-0058-3667-A2

Comment Excerpt Number: 7

Comment: There is no doubt that startups and shutdowns of BPH are a separate operating regime and that numerical emission limits cannot be met during such periods.

A. We agree with EPA's conclusion that BPH cannot meet numerical emission limits during startup and shutdown and simple work practice requirements are the only realistic way to manage emissions during these periods.

During periods of startup and shutdown, BPH35 cannot meet the numerical emission limits that they can meet during periods of normal operation because combustion controls do not work the same (e.g., oxygen levels cannot be controlled to the low levels achievable during normal operation) and combustion conditions are constantly changing as process duty, firing, air rates,

firebox draft, and firebox temperatures change. As EPA concluded, measurement of emissions is impossible because of the lack of steady state conditions and inability to optimize and hold any particular startup or shutdown operation constant. Thus a work practice approach is the only reasonable approach to dealing with startups and shutdowns.

[Footnote 35: EPA's discussion of startup and shutdown in the proposal preamble only mentions boilers, but process heaters are also subject to these requirements and, in general, are harder to manage during these periods than are boilers. Our comments address both boilers and process heaters.]

Response: The EPA thanks the commenter for their support. See the response to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46 under the chapter SS - Elements of Work Practices, regarding 25% load SS definition threshold, and comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5 also under the chapter SS - Elements of Work Practices, regarding use of manufacturer's specifications.

Commenter Name: Douglas A. McWilliams

Commenter Affiliation: American Municipal Power

Document Control Number: EPA-HQ-OAR-2002-0058-3685-A2

Comment Excerpt Number: 13

Comment: EPA Should Retain the Work Practice Standard Adopted in the March 21, 2011 Final Rule During Periods of Startup and Shutdown

AMP supports the inclusion of work practice standards for periods of startup and shutdown, but sees no need (and EPA has articulated no reason) to adopt work practice standards different from those adopted in the March 2011 Boiler MACT rule. In that rule, EPA properly determined that it was not feasible to establish numeric emission limits for periods of startup and shutdown due to the limited duration of startup and shutdown and the increased emissions that could result from requiring extended operation in this mode to facilitate testing to quantify emissions. Furthermore, the stack test data relied upon to establish emission limits does not reflect periods of startup and shutdown. In lieu of numeric emission limits, EPA developed a work practice standard pursuant to CAA § 112(h) that required sources to minimize emissions during periods of startup and shutdown using the manufacturer's recommended procedures or the procedures of a unit of similar design. In the Proposed Rule, EPA proposed additional work practice standards, claiming that "[g]eneral duty requirements do not constitute appropriate work practice standards under section 112(h)."22 EPA provided no reason for this change in position. Nothing in CAA § 112(h) suggests that a work practice standard of minimizing emissions using accepted emission reduction procedures is inadequate.

Response: The EPA thanks the commenter for their support. As noted in the preamble to the reconsideration proposal, petitioners requested certain clarification related to the startup and shutdown work practice standards. In addition, the EPA itself felt that certain changes needed to be made in the work practices so as to make them more consistent with other NESHAP actions and with the statutory requirements. Therefore, we proposed and took comment on the revised work practice standards. See elsewhere in this document our responses to suggested additional changes.

12B. Startup/Shutdown: Elements of Work Practices

Commenter Name: Jennifer Youngblood

Commenter Affiliation: National Tribal Air Association

Document Control Number: EPA-HQ-OAR-2002-0058-3667-A2

Comment Excerpt Number: 10

Comment: In specifying requirements related to startups and shutdowns the term "startup event" or "shutdown event" is used in some places in the rule (i.e., §63.7530(h), §63.7550(c)(14), §63.7555(i)). Those terms can be interpreted to mean something different than the definitions which use the word "period". Thus, we recommend all references in the rule to startup events and shutdown events be changed to just startup or shutdown or to startup periods and shutdown periods, as appropriate.

Response: The EPA appreciates the commenter's input. Since the definitions in the final rule refer to 'startup' and 'shutdown' we have removed references to the term events throughout the rule.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 158

Comment: If the requirement is maintained the certification must be revised. As discussed in Comment II.7.C.2, EPA indicated that the requirement to follow BPH manufacturer's specifications is to be deleted, so that language would need to be deleted from any NCS certification. Even more importantly, nothing in the proposed certification limits the certification to startups and shutdowns that occurred prior to the NCS submittal. Since BPH will be starting up and shutting down forever, any NCS certification must be limited to just the time period from the effective date of the BPH NESHAP to the date of the NCS submittal. Finally, since the startup and shutdown requirements apply to both boilers and process heaters, the certification presumably needs to address both, not just boilers.

Response: The EPA appreciates the commenter's input. The rule language was edited, and the statement requiring mention of startup/shutdown periods in the NCS was removed because startup/shutdown periods can occur at anytime.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 46

Comment: In the Reconsidered Boiler MACT Rule, EPA is also proposing definitions for "startup" and "shutdown." 76 Fed. Reg. 80,541. (2012 Reconsidered Rule). EPA is proposing to define "startup" as "the period between the state of no combustion in the boiler to the period where the boiler first achieves 25 percent load (i.e., a cold start)." 76 Fed. Reg. 80,654. EPA is

proposing to define “shutdown” as "the period that begins when a boiler last operates at 25 percent load and ending with a state of no fuel combustion in the boiler." 76 Fed. Reg. 80,654. EPA notes in the Reconsidered Major Source Rule, that the proposed definitions of "startup" and "shutdown" are intended to ensure that units cannot cycle in and out of startup or shutdown." 76 Fed. Reg. 80,615. (Reconsidered Boiler MACT Rule) Furthermore, EPA indicates that the definitions should provide "clarity regarding which periods of operation are subject to the work practice standards rather than numeric emission limits and the associated requirements." 76 Fed. Reg. 80,615. (Reconsidered Boiler MACT Rule) EPA is soliciting comment on the proposed definitions.

The proposed revision attempts to place all boilers into the same basket in specifying a 25% load threshold. This is not technically correct or practical on many fronts. How boilers "behave" is a function of fuel type, furnace and boiler design (combustion method), and operating methodologies. For example, some boilers have a minimum stable operating load that is higher than 25 percent, (e.g., stable operation for a stoker boiler may not be reached until 60 percent load). Additional examples include the fact that:

- Most solid fuel boilers do not reach stable operations until 50% load or higher while some oil and gas burners can function as low as 20% load for long duration.
- In facilities with solid fuel boilers that have significant steam load fluctuations (say between night and day), a boiler in hot standby is required to be ready to take on the added load within a short period of time. This standby boiler is "banked", which means the bed of fuel is hot and burning slowly, but no steam is being produced. No combustion air is being supplied. All that it then takes to bring the boiler on line is to initiate the input of combustion air to increase the combustion rate. Depending upon conditions, boilers can be in "banked" mode for hours to several days.
- Solid fuel units, particularly older anthracite units, will have a fire on the grate for several days to allow for slow heat-up of the refractory and other critical metal components. The slow heat up rate is necessary to prevent material damage to the unit. No steam is being produced during the warm-up period.
- Some facilities may have oil fired boilers that are sized correctly for winter heating loads, but are too big summer steam loads. Often, the unit may cycle on and off on the high pressure cutout because the facility steam load is below minimum firing rate for the unit.
- As previously mentioned, some oil boilers have burners that can function reliably down to 20% firing rate and do so for extended periods. In the case of low summer loads as noted above, these units may operate for extended periods between 20% and 25% load.
- Oil fired units in wet layup may use burner heat to generate natural circulation to mix up and circulate boiler water chemicals. No steam is generated during these events. The burner is operated at minimum firing rate which, as noted above, could be below 25%. The time of operation depends upon the size of the boiler and the burner rating at minimum fire.

Considering this, EPA should revise the startup definition to allow facilities to determine the minimum stable operating load on a unit-specific basis and include the minimum stable operating load that defines startup and shutdown and the proper procedures to follow during startup and shutdown in a site-specific plan. Establishment of the minimum stable operating load

on a site-specific basis is analogous to setting other boiler and control device operating parameter limits on a site-specific basis.

Response: A number of commenters indicated that the proposed load specifications (i.e., 25 percent load) within the definitions of “startup” and “shutdown” were inconsistent with either safe or normal (proper) operation of the various types of boilers and process heaters encountered within the source category. As the basis for defining periods of startup and shutdown, a number of commenters suggested alternative load specifications based on the specific considerations of their boilers; other commenters suggested the achievement of various steady-state conditions.

The EPA has reviewed these comments and agrees with the commenters that load conditions separating periods of startup and shutdown from periods of normal operation can be unit-specific and therefore presupposing certain load conditions in the definitions of periods of startup and shutdown is not appropriate. The EPA therefore believes adjustments are appropriate in the proposed definition of “startup” and “shutdown.” Affected boilers and process heaters function to supply steam for heating, supply indirect heating to processes, or, in the case of cogeneration units, generating electricity. Therefore these boilers and process heaters should be considered to be operating normally at all times during which steam of the proper pressure, temperature, and flow rate is being provided to a common header system or energy user(s) for use as either process steam, heat, or for the cogeneration of electricity. Accordingly, it is rational to separate periods of startup and shutdown from periods of normal operation based on supply of steam under proper conditions instead of specific load conditions (i.e., 25 percent load). We are revising the definitions of periods of startup and shutdown to account for these facts. We believe the revised definitions address the comments and are consistent with the definitions of startup and shutdown contained in the 40 CFR Part 63, subpart A General Provisions. We are finalizing definitions of “startup” and “shutdown” as follows:

Startup means either the first-ever firing of fuel in a boiler or process heater for the purpose of supplying steam or heat for heating and/or producing electricity, or for any other purpose, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam or heat from the boiler or process heater is supplied for heating and/or producing electricity, or for any other purpose.

Shutdown means the cessation of operation of a boiler for any purpose. Shutdown begins either when none of the steam or heat from the boiler or process heater is supplied for heating and/or producing electricity, or for any other purpose, or at the point of no fuel being fired in the boiler, whichever is earlier. Shutdown ends when there is both no steam or heat being supplied and no fuel being fired in the boiler.

In the final rule, the EPA is requiring sources to operate all continuous monitoring systems during startup and shutdown. For startup, we are requiring the source to use one or a combination of the listed clean fuels and once the source start firing coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel, or gas 2 (other) gases, they are required to engage all of the applicable control devices except limestone injection in FBC boilers, dry scrubber, fabric filter, SNCR, and SCR. The source is required to start the limestone injection in FBC boilers, dry scrubber, fabric filter, SNCR, and SCR systems as expeditiously as possible. During shutdown we are requiring the source while firing coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel, or gas 2 (other) gases during shutdown to operate all applicable control devices, except limestone

injection in FBC boilers, dry scrubber, fabric filter, SNCR, and SCR. The source is required to keep records during periods of startup or shutdown concerning the date, duration, and fuel usage during startup and shutdown.

The EPA carefully considered fuels and potential operational constraints of air pollution control devices when designing its work practices for periods of startup and shutdown. The EPA is aware that SNCR and SCR systems with ammonia injection need to be operated within a prescribed and relatively narrow temperature window to provide NO_x reductions. Further, the EPA is aware that dry scrubbers also need to be operated close to flue gas saturation temperature, and that fabric filters need to be operated at temperatures above the acid dew point. Because these devices have specific temperature requirements for proper operation, the EPA notes in its work practices that it is the responsibility of the operators of affected boilers and process heaters to start their SNCR, SCR, fabric filter, and dry scrubber systems appropriately to comply with relevant standards applicable during normal operation.

Commenter Name: Michael D. Wendorf
Commenter Affiliation: FMC Corporation
Document Control Number: EPA-HQ-OAR-2002-0058-3453-A1
Comment Excerpt Number: 10

Comment: FMC agrees with EPA's proposed definitions of startup and shutdown periods that identify a 25% load threshold in both cases.

Response: The EPA thanks the commenter for their support. We note, however, that we are modifying the definitions of startup and shutdown; see the response to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46 regarding the 25% threshold.

Commenter Name: Lee Zeugin and Lauren Freeman
Commenter Affiliation: Utility Air Regulatory Group (UARG)
Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1
Comment Excerpt Number: 24

Comment: UARG supports EPA's proposal to remove the requirement that facilities following manufacturers' recommended procedures to minimize emissions during startup. EPA's choice of 25 percent load as the endpoint for startup of an IB is reasonable.

Response: The EPA thanks the commenter for their support. We note, however, that we are modifying the definitions of startup and shutdown, see the response to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46 regarding the 25% threshold.

Commenter Name: Michael L. Krancer
Commenter Affiliation: Pennsylvania Department of Environmental Protection (DEP)
Document Control Number: EPA-HQ-OAR-2002-0058-3507-A1
Comment Excerpt Number: 19

Comment: The EPA has proposed to define startup and shutdown periods and more specific requirements than those in the final rule. The proposed definitions specify that only the periods

of time between a complete shutdown of a unit (no fuel being combusted) and the time that a unit first reaches 25 percent load qualify as startup, and only the periods of time between the time a unit last reaches 25 percent load and the time when a unit is completely shut down (no fuel being combusted) qualify as shutdown. The EPA believes that these definitions will ensure that units cannot cycle in and out of startup or shutdown.

The DEP believes that the revised "startup" and shutdown" definitions will provide clarity regarding which periods of operation are subject to the work practice standards rather than numeric emission limits and their associated requirements. Therefore, DEP agrees with EPA's approach of requiring work practice standards that apply during startup and shutdown periods.

Response: The EPA thanks the commenter for their support. We note, however, that we are modifying the definitions of startup and shutdown, see response to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46 regarding the 25% threshold.

Commenter Name: Mary Sullivan Douglas

Commenter Affiliation: National Association of Clean Air Agencies (NACAA)

Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1

Comment Excerpt Number: 46

Comment: NACAA agrees that a definition limiting the period of "startup" is appropriate. We recommend that such a definition be based on a percentage of the normal operating load of the unit as some sources may operate for extended periods of time at far less than the full rated capacity of the unit.

Response: The EPA thanks the commenter for their support. We note, however, that based on reasons cited by other commenters, we are modifying the definitions of startup and shutdown. See the response to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46 regarding the 25 percent load threshold.

Commenter Name: Bill Lane

Commenter Affiliation: American Home Furnishings Alliance (AHFA)

Document Control Number: EPA-HQ-OAR-2002-0058-3676-A2

Comment Excerpt Number: 7

Comment: AHFA supports EPA's proposal to refine the work practice standards for periods of startup and shutdown by including new definitions to clarify when the work practice standards would apply. AHFA agrees with EPA's proposed definition of "startup" as the period ramping up to 25 percent of load from a cold start and "shutdown" as the period ramping down from 25 percent of load to no fuel combustion.

Response: The EPA thanks the commenter for their support. We note, however, that we are modifying the definitions of startup and shutdown.

Commenter Name: Randal G. Oswald

Commenter Affiliation: Integrys Energy Group

Document Control Number: EPA-HQ-OAR-2002-0058-3659-A2

Comment Excerpt Number: 5

Comment: Integrys recommends that EPA define "startup" and "shutdown" according to manufacturer specifications. The proposed definitions of startup and shutdown are not readily applicable to all boilers, which have a wide variety of operating modes. EPA proposes to define "startup" as the period between a complete shutdown of a unit (no fuel being combusted) and the time that a unit first reaches 25 percent load, and proposes to define "shutdown" as the period of time between the time that a unit last reaches 25 percent load and the time when a unit is completely shut down (no fuel being combusted). Under the proposed definitions, units that regularly operate at loads below 25 percent of capacity would be in extended periods of startup and shutdown. Also, it would be extremely difficult for units that operate infrequently and do not monitor load, such as small auxiliary units, to determine when they first achieved or last operated at 25 percent load. EPA therefore should allow such units to determine when startup and shutdown begins based on manufacturer specifications. These specifications define startup and shutdown using factors more appropriate than load, such as the completion of specific procedures and run time. Defining startup and shutdown according to manufacturer specifications will address the operational differences among affected boilers and will not adversely impact public health or the environment.

Response: The EPA does not believe it appropriate to rely strictly on "manufacturer specifications" for periods of startup and shutdown. In some cases, the boiler or process heater may be so old that such specifications are either not available any more or are out-of-date. In other cases, modifications or additions to the boiler or process heater (e.g., control devices) have been made so as to make the original manufacturer specifications no longer relevant.

See also the response to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46, regarding the 25% load SS definition threshold.

Commenter Name: Russell A. Wozniak

Commenter Affiliation: The Dow Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3449-A1

Comment Excerpt Number: 38

Comment: Shutdown time of a combustion unit (e.g. the time between providing heat output and cutoff of fuel feeds) is typically short. For combustion units that are subject to a Table 1 or Table 2 emission limit and only burn Gas 1 fuel or Other Gas 1 fuel, the rule should provide that these units are also exempt from shutdown provisions. Dow believes that it would be appropriate to set the shutdown load criteria at a range from 5% to 25% load as defined by the owner/operator. If a Gas 2 fuel is burned until shutdown is complete, add-on emission control equipment that is otherwise required to meet a Table 1 or 2 emission limit should continue to be operated to minimize emissions.

Dow suggests the following changes to these definitions:

Shutdown means the period that begins when a unit last operates under stable low load conditions defined by the owner/operator (typically between 5 percent and 25 percent load) and ending with a state of no fuel combustion in the unit.

Response: The EPA does not believe it appropriate to exempt any units from the startup and shutdown provisions of the final rule because units subject to the emission limits in Table 1 or 2 of the final rule must be in compliance at all times which includes the work practices that apply to those units.

See the responses to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46, regarding 25% load SS definition threshold, and comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5, regarding use of manufacturer's specifications.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 45

Comment: In the Reconsidered Boiler MACT Rule, EPA is proposing to expand work practice standards for periods of startup and shutdown. Specifically, among other requirements, EPA is proposing that sources employ good combustion practices. 76 Fed. Reg. 80,602. CIBO supports the good combustion practices as proposed, but EPA should make clear that safety must be of central importance, and should include this critical caveat in its requires practices. consistent with safe operation.

These practices require these actions: You must employ good combustion practices and demonstrate that good combustion practices are maintained by monitoring O₂ concentrations and optimizing those concentrations as specified by the boiler manufacturer; you must ensure that boiler operators are trained in startup and shutdown procedures, including maintenance and cleaning, safety, control device startup, and procedures to minimize emissions; and you must maintain records during periods of startup and shutdown and include in your compliance reports the O₂ conditions/data for each event, length of startup/shutdown and reason for the startup/shutdown (i.e., normal/routine, problem/malfunction, outage).

76 Fed. Reg. 80,602.

Response: The EPA believes that commenter's concerns related to safety are already covered in §63.7500(a)(3) ("At all times, you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions.").

See the responses to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46, regarding 25% load SS definition threshold, and comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5, regarding use of manufacturer's specifications.

Commenter Name: LESLIE SUE RITTS

Commenter Affiliation: National Environmental Development Association's Clean Air Project (NEDA/CAP)

Document Control Number: EPA-HQ-OAR-2002-0058-3529-A1

Comment Excerpt Number: 6

Comment: NEDA/CAP agrees that all references to manufacturers' manuals should be removed from the MACT regulation. NEDA/CAP supports removal of references to either the boiler's manufacturer operation manual and/or pollution control manufacturer's operational manual. While very generally based on good engineering practices, the documents are recommendations and largely contractual elements related to vendor's guarantees and are not good guides for actual manufacturing processes. For instance, a vendor would not be aware of boiler operations that follow load in batching operations because they would likely be confidential and proprietary.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5, regarding use of manufacturer's specifications.

Commenter Name: Bruce W. Ramme

Commenter Affiliation: Wisconsin Electric Power Company (WE Energies)

Document Control Number: EPA-HQ-OAR-2002-0058-3452-A1

Comment Excerpt Number: 11

Comment: We Energies requests that EPA define the periods of startup and shutdown for affected units on the basis of source categories since startup and shutdown periods vary by boiler design and the fuel being combusted in those boilers (gaseous, liquid, and solid fuels). Currently, We Energies is constructing a 50-MW circulating fluidized bed boiler (CFB) next to an existing paper mill. This boiler has a maximum design heat input capacity of 800 million Btu per hour. The primary boiler fuels will be wood, bark, wood waste, forest residues, and wastewater treatment plant residue from the Domtar Paper Mill. The boiler will also utilize natural gas for startup fuel and combustion stabilization, with a maximum natural gas firing rate of less than 250 million Btu per hour. The CFB boiler will serve as the main source of steam for the mill, and therefore must have a high availability rate in order to reliably meet the mill's steam needs. The CFB boiler was not designed to come up to load quickly, taking approximately 16 – 18 hours to get up to full load during a typical start-up. By design, the boiler will initially fire on natural gas and then fire on biomass once the boiler is up to temperature, per the boiler manufacturer's startup procedures. The boiler manufacturer estimates that natural gas will be burned for an extended period of time before biomass fueling even begins. Based on EPA's proposed definition of startup, boilers of this type will have a difficult time meeting the proposed emission limits if the boiler experiences any startup complications. This is because at 25% load this boiler will still be firing primarily on natural gas, with inherently lower emission levels. Again, according to the boiler manufacturer, emissions will be at their highest when biomass fueling begins, later during startup, at around 30-45% load. Emissions become controllable when the selective non-catalytic reduction (SNCR) NO_x control equipment becomes effective which is at approximately 65% load. Since natural gas is initially being fired and emissions are low up to the introduction of biomass, EPA's definition of startup for this type of boiler should take into account the initial firing of biomass and its associated emissions.

In summary, even though a circulating fluidized bed boiler is very efficient at minimizing emissions once it reaches full load, this type of boiler and biomass fuel stock does require a longer startup period. Therefore EPA's proposed definition of the startup period as the time period between when no fuel is being combusted and the time that a unit first reaches 25 percent load is not compatible with the startup characteristics of a biomass-fueled CFB boiler.

Response: See the responses to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46, regarding 25% load SS definition threshold, and comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5, regarding use of manufacturer's specifications.

Commenter Name: Bruce W. Ramme

Commenter Affiliation: Wisconsin Electric Power Company (WE Energies)

Document Control Number: EPA-HQ-OAR-2002-0058-3452-A1

Comment Excerpt Number: 12

Comment: We Energies requests that EPA define startup and shutdown that is specific to the source category and takes into account boilers with longer startups and shutdowns. Specifically, for a CFB firing mainly on biomass, We Energies recommends that startup includes the period after biomass fuel is fired in the boiler and up to the point where the SNCR can be started. This definition will provide operational flexibility when starting up the biomass boiler while still achieving the IB-MACT emission limits.

Response: See the responses to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46, regarding 25% load SS definition threshold, and comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5, regarding use of manufacturer's specifications.

Commenter Name: Traylor Champion

Commenter Affiliation: Georgia-Pacific LLC (GP)

Document Control Number: EPA-HQ-OAR-2002-0058-3465-A1

Comment Excerpt Number: 12

Comment: EPA should eliminate the 25%-of-load threshold from the definition of start-up. There are a large number of boiler designs and a single 25% threshold is inappropriate for the full range of boilers. Some boilers with our company are not stable and therefore effectively in a start-up mode until they reach 50-60% of normal operating loads. The criteria for when a start-up ends should be driven by the manufacturer's recommendations and the operator's experience rather than an arbitrary percentage.

Response: See the responses to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46, regarding 25% load SS definition threshold, and comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5, regarding use of manufacturer's specifications.

Commenter Name: Robert E. Hunzinger

Commenter Affiliation: Gainesville Regional Utilities (GRU), Florida

Document Control Number: EPA-HQ-OAR-2002-0058-3488-A1

Comment Excerpt Number: 4

Comment: EPA's proposed definitions of startup and shutdown are not readily applicable to all boilers, which have a wide variety of operating modes. In some cases major source boilers will be of unique or limited design with specific startup and shutdown criteria. This will be the case with the Gainesville Renewable Energy Center (GREC). GRU is concern than a "one size fits all" definition for startup and shutdown may not be appropriate in some cases. GRU recommends

that EPA define "startup" and "shutdown" according to manufacturer specifications. We believe that EPA's proposal to define "startup" as the period between a complete shutdown of a unit (no fuel being combusted) and the time that a unit first reaches 25 percent load, and the proposal to define "shutdown" as the period of time between the time that a unit last reaches 25 percent load and the time when a unit is completely shut down (no fuel being combusted) may be inappropriate for some major source boilers.²

[Footnote]

(2) 76 Fed. Reg. at 80615.

Response: See the responses to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46, regarding 25% load SS definition threshold, and comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5, regarding use of manufacturer's specifications.

Commenter Name: Robert Cleaves

Commenter Affiliation: Biomass Power Association (BPA) and California Biomass Energy Alliance (CBEA)

Document Control Number: EPA-HQ-OAR-2002-0058-3489-A1

Comment Excerpt Number: 4

Comment: We support EPA's recognition of different emissions during startup and shutdown and its proposal to establish work practice standards during these periods. However, the concept needs two changes. First, the percentage should be calculated on the basis of design load. Design load is established by the physical configuration of the boiler and any threshold level at which the boiler becomes stable during startup is related to its physical design, not some lower load level at which the source may choose to operate.

Second, the percent load at which the unit emissions become normal differs by technology. Gaseous and liquid fuel burners have lower percent threshold than solid stoker boilers or fluidized bed combustors. BPA requests that EPA modify the definitions of startup and shutdown to allow sources and State regulators to specify the numerical percent values appropriate for the technology in the sources permits.

Response: See the responses to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46, regarding 25% load SS definition threshold, and comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5, regarding use of manufacturer's specifications.

Commenter Name: Michael Bradley

Commenter Affiliation: The Clean Energy Group

Document Control Number: EPA-HQ-OAR-2002-0058-3495-A1

Comment Excerpt Number: 7

Comment: EPA proposes to revise the work practice standards for startup and shutdown to include a definition of startup and shutdown as well as to standardize requirements. Startup would be defined as the period between no combustion and 25 percent load, and shutdown would be defined as the period between 25 percent load and no combustion. EPA requests comment on the need for and an

appropriate duration limit for startup and shutdown periods during which numeric emission limits do not apply. The Clean Energy Group agrees with the need for a definition of startup and shutdown in light of the final rule's use of work practices for these periods. However, rather than 25 percent load, which may be inappropriate for many units, we recommend EPA alter the definition of startup to reflect unit-specific considerations, such as defining the end of startup as when the unit reaches the minimum safe operating load or when compliance with Title V emission limits is reached. Similarly, EPA could define shutdown as the period of time from when a unit reduces load with the intent to shut down and ends with the cessation of combustion of fuel. This would avoid defining as "shutdown" those circumstances where units may need to operate at a level below 25 percent, but above the minimum safe operating load.

In this way, EPA would utilize definitions already incorporated into existing air quality operating permits. Typically, these definitions are jointly established by the responsible air permitting authorities and the individual facility because startup and shutdown periods are somewhat unique to each boiler design. Operation below the unit-specific "normal operating mode" is when startup and shutdown requirements should apply. We recommend that EPA not numerically define startup and shutdown in the final rule, and instead defer to the definitions contained in currently active air quality operating permits issued by local and/or state air permitting agencies.

Response: See the responses to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46, regarding 25% load SS definition threshold, and comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5, regarding use of manufacturer's specifications.

Commenter Name: David A. Buff, Golder Associates Inc.

Commenter Affiliation: Florida Sugar Industry (FSI)

Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1

Comment Excerpt Number: 52

Comment: EPA has included a threshold of 25 percent load in its definition of startup and shutdown. Some units have a minimum stable operating load that is significantly higher than 25 percent. For example, stable operation of a hybrid suspension grate boiler may not be reached until the boiler achieves 60 percent load. Therefore, EPA should revise the startup definition to allow facilities to determine the minimum stable operating load on a unit-specific basis. The minimum stable operating load that defines startup and shutdown, and the proper procedures to follow during startup and shutdown, can be included in a site-specific operating plan.

Response: See the responses to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46, regarding 25% load SS definition threshold, and comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5, regarding use of manufacturer's specifications.

Commenter Name: Mark D. Pettegrew

Commenter Affiliation: PolyOne Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3513-A1

Comment Excerpt Number: 2

Comment: The PolyOne Henry Illinois facility is also equipped with two natural gas boilers which serve as backup to the coal fired boiler. However, during the winter the gas boilers are

used to complement the coal boiler because demand for steam load for both production and building heat can exceed the output capabilities of the coal fired boiler. The gas boilers would run under 25% loading during these circumstances. Under the current proposal, a minimum 25% load is established which means the gas boiler cannot be run under 25% load. The boiler would need to be shut down. Without the capability of running the gas boiler under 25% load, the plant would have to run above this limit, and vent the excess steam produced to the atmosphere wasting energy and increasing operating costs. We suggest a revision to the 25% minimum load requirement.

Response: See the responses to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46, regarding 25% load SS definition threshold, and comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5, regarding use of manufacturer's specifications.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 14

Comment: EPA has included a threshold of 25 percent load in its definition of startup and shutdown. Some units have a minimum stable operating load that is higher than 25 percent (e.g., stable operation for a stoker boiler may not be reached until 60 percent load). Therefore, EPA should revise the startup definition to allow facilities to determine the minimum stable operating load on a unit-specific basis. Startup should end when combustion conditions are stable for a particular unit, which is not always at 25 percent load. In some cases, this may be when the unit begins sending steam to the process.

Response: See the responses to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46, regarding 25% load SS definition threshold, and comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5, regarding use of manufacturer's specifications.

Commenter Name: Ahmed Idriss, Capital Power Corporation

Commenter Affiliation: CPI USA North Carolina (CPI NC)

Document Control Number: EPA-HQ-OAR-2002-0058-3524-A1

Comment Excerpt Number: 5

Comment: CPI NC does not support the EPA's proposed definition for start-up and shut-down. These definitions incorrectly assume that all boilers have similar design and operating parameters.

CPI NC proposes the definitions for start-up and shut-down be revised. Start-up should be defined as the period between the state of no combustion and the minimum stable operating conditions for each unit. Shut-down should be defined as the period between beginning when a unit last operates at the minimum stable operating condition and ending at the state of no combustion. Minimum stable operating conditions should be unit specific depending on the operating profile and qualities of each individual unit. CPI NC believes this definition is reasonable, as the definition provides appropriate parameters for each individual unit.

Response: See the responses to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46, regarding 25% load SS definition threshold, and comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5, regarding use of manufacturer’s specifications.

Commenter Name: LESLIE SUE RITTS

Commenter Affiliation: National Environmental Development Association's Clean Air Project (NEDA/CAP)

Document Control Number: EPA-HQ-OAR-2002-0058-3529-A1

Comment Excerpt Number: 1

Comment: NEDA/CAP submits that EPA’s proposed definitions of “startup” and “shutdown” are arbitrary and unreasonable. A one-size fits all definition of “startup” or “shutdown” does not exist, which is why work practice standards should apply the entire time until a boiler reaches a steady state.

EPA finalized a work practice standard for periods of startup and shutdown in the March 21, 2011 Final ICI MACT, which will require facilities to minimize emissions consistent with manufacturer’s recommended procedures during “startup” and “shutdown” of a boiler – but not during “malfunctions.” (The ICI MACT emission limits will apply to “malfunctions” although sources will be afforded the opportunity to mount an affirmative defense to any violations of the emission limitations attributable to a “malfunction” of either the emissions or pollution control equipment.) EPA now proposes to define startup and shutdown periods “to provide clarity regarding which periods of operation are subject to the work practice standards rather than numeric emission limits and the associated requirements.” *Id.* 80615. EPA reasons that the definitions are intended to ensure that units cannot cycle in and out of startup or shutdown. *Id.*

NEDA/CAP refutes the existence of any basis for EPA’s concern that affected units will circumvent compliance with the ICI MACT emission limits by “cycling” in and out of operation to avoid application of the ICI MACT. Without such a finding, the proposal is an unreasonable solution in search of a problem. If the Agency’s final rule retains definitions of these terms, EPA must provide a factual basis for its concerns that can be addressed on a regulatory rather than an enforcement basis. Otherwise this provision would particularly harm manufacturers that can no longer operate three shifts a day and batch processors whose steam demand (and hence boiler load) swing widely.

Response: See the responses to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46, regarding 25% load SS definition threshold, and comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5, regarding use of manufacturer’s specifications.

Commenter Name: LESLIE SUE RITTS

Commenter Affiliation: National Environmental Development Association's Clean Air Project (NEDA/CAP)

Document Control Number: EPA-HQ-OAR-2002-0058-3529-A1

Comment Excerpt Number: 3

Comment: Seemingly, in recognition of the arbitrary nature of the 25% -based definition, EPA explains that the agency feels that it must establish a “maximum time period to ensure that units

cannot operate in startup or shutdown mode for extended periods of time,” and therefore is soliciting comment on the appropriate time period or time periods for the various unit designs. *Id.* This solicitation appears to us to be a dangerous trap, because there is (as EPA recognizes in the same discussion) very poor information about emissions during startup and shutdown, which is why the Agency properly established a work practice standard in lieu of establishing a numerical limitation. As CAA Section 112(h) states, when it is not feasible for the Administrator to prescribe or *enforce an emission standard* for control of hazardous air pollutants, the Administrator may, in lieu thereof, promulgate a design, equipment, work practice or operational standard, which is consistent with Section 112(d). Further, NEDA/CAP asserts that it is not possible to *prescribe* a numerical definition of “startup” or “shutdown.”

Response: See the responses to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46, regarding 25% load SS definition threshold, and comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5, regarding use of manufacturer’s specifications.

Commenter Name: LESLIE SUE RITTS

Commenter Affiliation: National Environmental Development Association's Clean Air Project (NEDA/CAP)

Document Control Number: EPA-HQ-OAR-2002-0058-3529-A1

Comment Excerpt Number: 5

Comment: If EPA [maintains a prescriptive 25% threshold], then the Agency needs to provide a rationale that distinguishes the concerns it raises about cycling boilers from multiple startups and shutdowns of boilers in batching industries and due to the economy. The December 23, 2011 Notice suggests that EPA’s concerns about startup and shutdown may be related to how many times a unit starts up or shuts down a unit. The final rule should carefully consider that at least two situations merit multiple starts and shut-offs of a boiler and distinguish these situations from the circumstances that suggest circumvention of the ICI MACT limits. First, manufacturers generally shut off or idle boilers if they are not running three shifts or five days a week, because fuel is generally one of the most expensive commodities in the manufacturing process. As a result multiple startups and shutdowns are legitimate reflections of operations. Second, starting and shutting off a six or seven or nine story building is inherently dangerous and simply stated, one does not want to put hot gases into a cold control technology without bringing both the unit and the control “up” over time. Safety concerns, particularly for some boilers that are still lit manually in fireboxes, also are notorious for dangers and difficulties during startup that may require multiple startups and are unavoidable, though foreseeable. Even oil-fired ignition guns on modern boilers are well-known to require multiple startups on occasion because they plug or misfire in an unavoidable manner. For these reasons and others, defining startup or shutdown with reference to how many times they occur does not necessarily indicate behavior that should be punished under the Clean Air Act.

Response: See the responses to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46, regarding 25% load SS definition threshold, and comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5, regarding use of manufacturer’s specifications.

Commenter Name: Frank H. Thorn
Commenter Affiliation: Newport News Shipbuilding
Document Control Number: EPA-HQ-OAR-2002-0058-3548-A2
Comment Excerpt Number: 7

Comment: The NNS Floating Test Steam Facility (FTSF) boilers are marine boilers utilized in a unique manner and are not designed, constructed or operated like industrial, commercial or institutional boilers.

In the Proposed Rule EPA introduced new definitions of “startup” (the period between the state of no combustion and when a unit first reaches 25 percent load) and “shutdown” (the period between when a unit last reaches 25 percent load and the time when a unit is completely shut down). In the Preamble EPA stated that the definitions of “startup” and “shutdown” are intended to ensure that industrial, commercial and institutional units cannot cycle in and out of startup or shutdown. In contrast the FTSF boilers operate the majority of their time within the range that EPA has determined to constitute startup or shutdown. Analysis of the actual, measured daily loads experienced by the FTSF boilers over the entire steaming period of the most recent aircraft carrier at NNS shows that the FTSF boilers operate at or below 25% load approximately 85% of the time, as depicted in Exhibit 3. The unique nature of propulsion plant testing requires that the FTSF boilers operate below 25 percent load for sustained periods up to several weeks. The FTSF boilers routinely achieve high turndown ratios (operation at very low loads) that industrial, commercial and institutional boilers are not designed to accomplish.

Response: See the responses to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46, regarding 25% load SS definition threshold, and comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5, regarding use of manufacturer’s specifications.

Commenter Name: Tangela Niemann
Commenter Affiliation: Texas Commission on Environmental Quality (TCEQ)
Document Control Number: EPA-HQ-OAR-2002-0058-3594-A3
Comment Excerpt Number: 12

Comment: Based on the EPA’s proposed definition of *shutdown*, a shutdown period begins when a boiler last operates at 25% load. Similarly, the proposed definition of *startup* states that a startup period ends when the boiler first achieves 25% load. The 25% load threshold used in both definitions might be interpreted as a percentage of the operating load or as a percentage of the design capacity load of the boiler. In some cases, the boiler may be oversized for the demand and the boiler may rarely operate at or near full capacity. In some instances the normal operating load of a boiler may rarely or never exceed 25% of the design capacity. The EPA should revise the definitions of *startup* and *shutdown* to specify that the 25% threshold is based on the percentage of normal operating load of the boiler and provide a definition of what is considered normal operating load.

Response: See the responses to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46, regarding 25% load SS definition threshold, and comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5, regarding use of manufacturer’s specifications.

Commenter Name: Allison Watkins, Baker Botts
Commenter Affiliation: Class of '85 Regulatory Response Group
Document Control Number: EPA-HQ-OAR-2002-0058-3608-A1
Comment Excerpt Number: 5

Comment: The Group recommends that EPA define “startup” and “shutdown” according to manufacturer specifications. The proposed definitions of startup and shutdown are not readily applicable to all boilers, which have a wide variety of operating modes. EPA proposes to define “startup” as the period between a complete shutdown of a unit (no fuel being combusted) and the time that a unit first reaches 25 percent load, and proposes to define “shutdown” as the period of time between the time that a unit last reaches 25 percent load and the time when a unit is completely shut down (no fuel being combusted).⁵ Under the proposed definitions, units that regularly operate at loads below 25 percent of capacity would be in extended periods of startup and shutdown. Also, it would be extremely difficult for units that operate infrequently and do not monitor load, such as small auxiliary units, to determine when they first achieved or last operated at 25 percent load. EPA therefore should allow such units to determine when startup and shutdown begins based on manufacturer specifications. These specifications define startup and shutdown using factors more appropriate than load, such as the completion of specific procedures and run time. Defining startup and shutdown according to manufacturer specifications will address the operational differences among affected boilers and will not adversely impact public health or the environment.

Response: See the responses to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46, regarding 25% load SS definition threshold, and comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5, regarding use of manufacturer’s specifications.

Commenter Name: C. Richard Neff
Commenter Affiliation: Cogentrix Energy, LLC
Document Control Number: EPA-HQ-OAR-2002-0058-3627-A2
Comment Excerpt Number: 2

Comment: Cogentrix concurs with the work practice standard that requires sources to minimize periods of startup and shutdown following the manufacturer's recommended procedure. For stoker coal boilers designed to operate as electric utility steam generating units, the manufacturer's recommended procedure includes building a stable ash bed on grate - to assure efficient combustion that can minimize both CO and NO_x formation - prior to bringing the unit to its minimum load point. In these instances, the minimum load point is 50 percent, and the time to achieve that point is eight (8) hours after initial firing, whichever is shorter. Therefore, Cogentrix proposes that the definitions for startup and shutdown be revised as follows, so that they reflect manufacturers' recommended procedures:

"Startup means the period between the state of no combustion in the unit and the period when the unit first achieves the manufacturer's recommended minimum load (i.e., a cold start) or a maximum of eight (8) hours, whichever is shorter"; and "Shutdown means the period that begins when a unit last operates at the manufacturer's recommended minimum load and ends with a state of no fuel combustion in the unit."

Response: See the responses to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46, regarding 25% load SS definition threshold, and comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5, regarding use of manufacturer's specifications.

Commenter Name: Vickie Woods

Commenter Affiliation: Division of Air Quality, North Carolina Department of Environment and Natural Resources (NCDENR)

Document Control Number: EPA-HQ-OAR-2002-0058-3663-A2

Comment Excerpt Number: 22

Comment: EPA not proposing to change malfunction provisions, but proposing revised work practice standards for S/S. EPA proposing to define startup as period between state of no combustion to period where unit first achieves 25% load; and define shutdown as period beginning when unit last operates at 25% load and ending with no fuel combustion. Proposing to employ good combustion practices and demonstrate practices are maintained by monitoring O₂ and optimizing those levels as specified by boiler manufacturer; ensure boiler operators are trained in S/S, including safety, control device startup, minimizing emissions; and maintain records during S/S and include in compliance reports the O₂ conditions /data for each startup event, length and reason of S/S.

NC DAQ supports the use of work practices for both startup and shutdown of boiler operations and is generally in favor of simpler definitions for these operational periods. However, the operations during conditions defined as shutdown (less than 25% of load to no fuel) would be easier to meet in practice than the startup conditions. NC DAQ believes that a source should have the option to use another alternative to the proposed startup load definition while maintaining work practice requirements. Other alternatives for defining startup are temperatures associated with control equipment operation and not-to-exceed time limits in reaching these conditions to avoid overly lengthy startups.

Response: See the responses to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46, regarding 25% load SS definition threshold, and comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5, regarding use of manufacturer's specifications.

Commenter Name: Jennifer Youngblood

Commenter Affiliation: National Tribal Air Association

Document Control Number: EPA-HQ-OAR-2002-0058-3667-A2

Comment Excerpt Number: 12

Comment: The first sentence of the Table 3 Item 5 requirements is: "You must employ good combustion practices and demonstrate that good combustion practices are maintained by monitoring O₂ concentrations and optimizing those concentrations as specified by the boiler manufacturer". However, EPA states in the preamble³⁷ that the requirement in the March 21, 2011 rule that startup and shutdown procedures follow manufacturer's recommendations is being removed. This is an important change that should be finalized and be reflected in Table 3. Although no longer required, EPA states that it expects facilities will follow manufacture recommendations for boiler systems and control devices and we concur where the manufacturer's recommendations exist and are relevant.

Response: See the responses to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46, regarding 25% load SS definition threshold, and comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5, regarding use of manufacturer's specifications.

Commenter Name: Jennifer Youngblood
Commenter Affiliation: National Tribal Air Association
Document Control Number: EPA-HQ-OAR-2002-0058-3667-A2
Comment Excerpt Number: 19

Comment: It is worth noting that while numerical emission limits (lb/MMBTU) may be exceeded during low firing rate operations, because of the low firing the mass of emission (total pounds) will be quite low.

Response: See the responses to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46, regarding 25% load SS definition threshold, and comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5, regarding use of manufacturer's specifications.

Commenter Name: Robin Mills Ridgway
Commenter Affiliation: Purdue University
Document Control Number: EPA-HQ-OAR-2002-0058-3668-A2
Comment Excerpt Number: 3

Comment: In §63.7575, EPA defines "startup" and "shutdown" as being the operational load of a unit at less than 25% of the unit's design capacity. This arbitrary 25% cutoff is problematic for many industrial units. For example: Purdue University's Boiler #5 is rated at 200 kpph. Using the repropoed rule's cutoff, 25% would be 50 kpph, making 50 kpph the load threshold between startup/shut down and operational. However, at loads as low as 50 kpph, this unit is in danger of tripping due to combustion instability and is not stable until it reaches 80 kpph. Purdue University's Wade Utility Plant's boilers are affected units in the CAIR ozone season NOx program. In Purdue's Part 75 monitoring plan, 80 kpph is the certified minimum stable operating load for Boiler #5. Purdue suggests the use of the "minimum stable operating load" as defined by 40 CFR Part 75 Appendix A 6.5.2.1 instead of the arbitrary 25% design capacity threshold proposed in the Boiler MACT.

Response: See the responses to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46, regarding 25% load SS definition threshold, and comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5, regarding use of manufacturer's specifications.

Commenter Name: Steve Gossett
Commenter Affiliation: Eastman Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3669-A2
Comment Excerpt Number: 33

Comment: The designation of a set percentage of load to define a startup is inappropriate and arbitrary. There are vast differences among boiler designs that would dictate at what load it is safe to end the startup. We give the following two actual examples of boilers at our facility that

demonstrate that 25 percent of rated capacity is arbitrary to define the end of startups for these boilers:

Example 1: Pulverized coal boilers

Both No. 30 and 31 boilers are pulverized coal boilers which produce 1450 psig steam that is routed through a turbine to generate electricity or bypass valve that exhausts to the plant at 600 psig. When starting up from a cold start, operations follows a very detailed (105 steps) check sheet. The general order of startup includes: making sure all valves and dampers are in correct position, warming up boiler using natural gas igniters, placing particulate control device in service, placing a coal mill in service and opening pressure reducing valve in the steam header, placing spray dryer absorber (SDA) in service, and placing steam turbine generator in service. Alternately, if the steam turbine generator is not available, steam can continue to be routed through the pressure reducing valve. Upon startup of the first mill the boiler load is approximately 40% of MCR. It is at this load that the SDA is brought online, and the unit is typically held at this level until the SDA startup is complete and the turbine generator is synchronized and begins producing electricity. Using the EGU logic to define startup, this 40% of MCR would be considered the load at which the unit is considered to be "online."

Example 2: Stoker boilers

Nos. 18-20 Boilers are moving grate spreader stoker coal boilers which produce 600 psig steam. Before coal is ignited, the electrostatic precipitators are energized. Coal is then placed on the grates and ignited. Feeders are cycled on- and offline in order to evenly add heat to slowly pressurize the boiler without damaging the refractory or tubes, per the manufacturer's startup curve for pressure increase with respect to time. As the boiler begins making steam and its pressure begins to increase, steam is vented to atmosphere to provide cooling flow to the boiler superheaters. When the steam pressure nears 600 psig, the header valve is opened. The boiler is equipped with a non-return valve so steam from the header will not flow back into the boiler, so when boiler pressure meets or exceeds the 600 psig header pressure steam will exit the boiler and enter the header. However, for super heater cooling purposes, the vent to atmosphere is not closed until the boiler outlet steam has exceeded 37.5% of MCR. This is the point at which startup is considered complete and the unit is "online."

Startups can vary for a variety of reasons, and the minimum safe and stable load is determined by the boiler OEM based on the unique characteristics and design pressure of the specific unit. For EPA to presume that a universal load point can be identified is false. Rather, EPA should acknowledge the vast diversity of the population of boilers being regulated and allow sources the flexibility to use the OEM's recommended minimum safe and stable operating load to define the end of startup, or to petition the Administrator if such guidance is not available or if other qualified experts can substantiate a different load point.

Response: See the responses to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46, regarding 25% load SS definition threshold, and comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5, regarding use of manufacturer's specifications.

Commenter Name: Heather Parent

Commenter Affiliation: Maine Department of Environmental Protection

Document Control Number: EPA-HQ-OAR-2002-0058-3691-A2

Comment Excerpt Number: 6

Comment: While Maine DEP supports the incorporation of work practice standards in place of emission standards during startup and shutdown periods, Maine DEP disagrees with a 25% percent of load trigger for normal operating conditions. Startup conditions, particularly with biomass and multi fuel units, can occur well beyond 25% of load up to more than 50% load. Maine DEP suggests that EPA reconsider the 25% of load trigger taking into account how biomass units startup differently than liquid or gas fired units.

Response: See the responses to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46, regarding 25% load SS definition threshold, and comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5, regarding use of manufacturer's specifications.

Commenter Name: Samuel H. Bruntz

Commenter Affiliation: Alcoa Power Generating, Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3755-A1

Comment Excerpt Number: 14

Comment: Proposed regulation 63.7575 defines start-up as the period between the state of no combustion in the unit to the period where the unit first achieves 25 percent load (*i.e.*; a cold start), and defines shutdown as the period that begins when a unit last operates at 25 percent load and ending with a state of no fuel combustion in the unit.

Alcoa - Warrick appreciates the intent of EPA to require compliance with work practice standards instead of emission limits, as indicated in 63.7500(e) during start-up and shutdown events. However, Alcoa~ Warrick is concerned that EPA may not be aware of the requirement that boilers that produce steam to drive a turbine maintain a "soak condition" for a period of approximately 4 hours to allow proper turbine start-up. During that 4 hour period, the associated boiler may fluctuate between 25-27% load, but would attempt to hold the load in a range that does not constantly stay at 25% load. Due to the turbine soak requirement, Alcoa ~ Warrick requests that the definitions of start-up and shutdown in 63.7575 be amended as follows:

Start-up means the period between the state of no combustion in the unit to the period when the unit first achieves 30 percent load (i.e. a cold start).

Shutdown means the period that begins when a unit last operates at 30% load and ending with a state of no fuel combustion in the unit.

Response: See the responses to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46, regarding 25% load SS definition threshold, and comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5, regarding use of manufacturer's specifications.

Commenter Name: Traylor Champion

Commenter Affiliation: Georgia-Pacific LLC (GP)

Document Control Number: EPA-HQ-OAR-2002-0058-3465-A1

Comment Excerpt Number: 5

Comment: GP strongly opposes establishing specific time limits due to the wide variation in boiler designs, operating variables and many other factors that affect the time required to safely start up and shut down a boiler. Boiler manufacturers set forth appropriate startup / shutdown sequences for safety as well as minimizing stresses and preventing damage to the equipment. We understand EPA's desire to establish a maximum time limit for startup and shutdown periods and agree that these periods should be minimized to the greatest extent practicable. Unfortunately, there simply is no practical means of developing a "one-size-fits-all" standard that is appropriate for all boiler designs and configurations. In fact, time limits could have the perverse effect of forcing operators to forgo manufacturer's operating guidance and incur unnecessary wear and tear over time. Overstressing the boiler will, in the long run, adversely impact combustion efficiency and the boiler's reliability. All of these outcomes would result in increased emissions. Furthermore, time limits are really unnecessary as operators already have strong economic incentives to minimize these periods to the extend practical and expeditiously transition operation of the boiler to a normal operating range.

Response: The EPA is not specifying time limits for periods of startup and shutdown.

See the response to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46, regarding 25% load SS definition threshold, and comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5, regarding use of manufacturer's specifications.

Commenter Name: Traylor Champion

Commenter Affiliation: Georgia-Pacific LLC (GP)

Document Control Number: EPA-HQ-OAR-2002-0058-3465-A1

Comment Excerpt Number: 6

Comment: Boiler manufacturers provide curves that establish the minimum time required to start up and shut down a boiler. These curves are based on specific boiler design and are intended to protect boiler components from excessive stresses resulting from differential expansion. The startup/shutdown curves for an individual boiler must be followed to ensure that the pressure parts of the boiler are not stressed beyond acceptable tolerances. Accelerating the startup/shutdown procedures can significantly reduce the life of boiler components and in some cases can result in immediate pressure part failure. The start-up curve will not be the same for all boilers. The major factor used to develop a start-up curve is drum thickness. The thicker the drum plate, the longer the boiler will take for it to reach equilibrium, and the longer the required start-up curve. Differential expansion of other components, such as headers and downcomers, must also be taken into consideration.

Response: See the responses to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46, regarding 25% load SS definition threshold, and comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5, regarding use of manufacturer's specifications. See the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 5, regarding maximum time limit for startup/shutdown.

Commenter Name: Traylor Champion

Commenter Affiliation: Georgia-Pacific LLC (GP)

Document Control Number: EPA-HQ-OAR-2002-0058-3465-A1

Comment Excerpt Number: 7

Comment: Many industrial boilers have non-drainable, pendant-style superheater sections and the start-up procedure for these boilers requires that all the water is boiled out of the superheater tubes as part of the start-up process. These tubes are exposed to hot gases from the furnace and depend on steam flow through the tubes for cooling. Any water in the tubes blocks the flow of steam. The superheater tubes will normally be partially or completely full of water following an outage with the source of water being either steam that condensed during the shutdown of the boiler or water used to hydrostatically test the boiler for leaks prior to startup. The start-up process requires that the gas temperature be limited to 900°F entering the superheater until: (1) all the water is boiled out of every element, and (2) steam flow is a minimum of 10% of rated capacity to ensure flow through all the tubes. Failure to clear the superheater of water and establish sufficient steam flow prior to increasing gas temperature can result in overheating and failure of the superheater tubes. The time required to clear a superheater is a function of boiler design, the size and design of the superheater, and the fuel being fired. Clearing the superheater of water, especially on larger, high pressure, high temperature boilers, often exceeds the minimum time established by the manufacturers' startup curve and becomes the controlling factor regarding the duration of start-up events.

Response: See the responses to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46, regarding 25% load SS definition threshold, and comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5, regarding use of manufacturer's specifications. See the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 5, regarding maximum time limit for startup/shutdown.

Commenter Name: Traylor Champion

Commenter Affiliation: Georgia-Pacific LLC (GP)

Document Control Number: EPA-HQ-OAR-2002-0058-3465-A1

Comment Excerpt Number: 8

Comment: Ash deposits on a superheater can also extend the time required to clear the superheater of water. Ash deposits act as an insulating layer, reducing the heattransfer rate to the tubes, and extending the time required for startup.

Response: See the responses to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46, regarding 25% load SS definition threshold, and comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5, regarding use of manufacturer's specifications. See the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 5, regarding maximum time limit for startup/shutdown.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 114

Comment: ACC believes the following types of concepts could be used as being indicative of a boiler or process heater reaching the end of a startup period (the beginning of a startup would occur with first introduction of fuel with combustion in the furnace):

- Boiler or process heater firing its primary fuel for a period of time adequate to provide stable and non-interrupted fuel flow, stable and controlled air flows, and adequate operating temperatures to allow proper fuel drying and air preheat as applicable.
- Emissions controls in service with operating parameters such as flow rates and temperatures being controlled and stable.
- Boiler or process heater supplying steam or energy output to a common header system or energy user(s) at normal operating conditions including pressure, temperature, and above minimum operational output flow rate, as applicable to the unit.

Response: See the responses to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46, regarding 25% load SS definition threshold, and comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5, regarding use of manufacturer's specifications. See the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 5, regarding maximum time limit for startup/shutdown.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 115

Comment: Similarly, ACC believes the following types of concepts could be used as being indicative of a boiler or process heater beginning a shutdown period (the end of a shutdown would occur with the cessation of combustion of any fuel in the furnace):

- Cessation of introduction of the last remaining primary fuel to the furnace, whether or not a supplemental support fuel is being used.
- Cessation of emissions control system sorbent or other reagent injection.
- Lowering the fuel firing rate to the point that automatic control is no longer effective or possible.
- Lowering of operating rates to the point that emissions control systems no longer can be controlled or be effective due to low flow rates, low temperatures, or other issues.
- Lowering boiler or process heater output to the point that steam or energy output no longer meets operational required conditions of pressure, temperature, or flow.

Response: See the responses to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46, regarding 25% load SS definition threshold, and comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5, regarding use of manufacturer's specifications. See the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 5, regarding maximum time limit for startup/shutdown.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 47

Comment: We believe the following types of concepts could be used as being indicative of a boiler reaching the end of a startup period (the beginning of a startup would occur with first introduction of fuel with combustion in the furnace):

- Boiler firing its primary fuel for a period of time adequate to provide stable and non-interrupted fuel flow, stable and controlled air flows, and adequate operating temperatures to allow proper fuel drying and air preheat as applicable.
- Emissions controls in service with operating parameters such as flow rates and temperatures being controlled and stable.
- Boiler supplying steam to a common header system or energy user(s) at normal operating conditions including pressure, temperature, and above minimum operational output flow rate, as applicable to the unit.

Response: See the responses to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46, regarding 25% load SS definition threshold, and comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5, regarding use of manufacturer's specifications. See the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 5, regarding maximum time limit for startup/shutdown.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 48

Comment: Similarly, we believe the following types of concepts could be used as being indicative of a boiler beginning a shutdown period (the end of a shutdown would occur with the cessation of combustion of any fuel in the furnace):

- Cessation of introduction of the last remaining primary fuel to the furnace, whether or not a supplemental support fuel is being used.
- Cessation of emissions control system sorbent or other reagent injection.
- Lowering the fuel firing rate to the point that automatic control is no longer effective or possible.
- Lowering of operating rates to the point that emissions control systems no longer can be controlled or be effective due to low flow rates, low temperatures, or other issues.
- Lowering boiler output to the point that steam no longer meets operational required conditions of pressure, temperature, or flow.

Response: See the responses to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46, regarding 25% load SS definition threshold, and comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5, regarding use of manufacturer's specifications. See the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 5, regarding maximum time limit for startup/shutdown.

Commenter Name: Vickie Woods

Commenter Affiliation: Division of Air Quality, North Carolina Department of Environment

and Natural Resources (NCDENR)

Document Control Number: EPA-HQ-OAR-2002-0058-3663-A2

Comment Excerpt Number: 1

Comment: EPA is proposing to change the work practice standards to better reflect the maximum achievable control technology and to change the proposed definitions of startup and shutdown. EPA proposes to define startup as the period between the state of no combustion in the boiler to the period where it first achieves 25% load (i.e., a cold start). Similarly, EPA proposes to define shutdown as the period that begins when a unit last operates at 25% load and ending with a state of no fuel combustion in the unit. For periods of startup and shutdown, EPA proposes the following work practice standard:

Affected facilities must employ good combustion practices and demonstrate good combustion practices are maintained by monitoring oxygen (O₂) concentrations and optimizing those concentrations as specified by the boiler manufacturer.

Facilities must ensure boiler operators are trained in startup and shutdown procedures, including maintenance and cleaning, safety, control device startup, and procedures to minimize emissions.

Facilities must maintain records during periods of startup and shutdown and include in their compliance reports the O₂ conditions/data for each startup event, length of startup shutdown and reason for the startup/shutdown (i.e., normal/ routine, problem/malfunction, outage). And

Facilities must comply with all applicable emissions limits at all times except for startup and shutdown periods, during which times facilities must comply with these work practices.

NC DAQ Comment:

We support EPA's proposal on the above points except for the proposed definition of startup. We favor a change in the Boiler MACT's definition of *startup* that resembles the EGU MACT's definition where the end of startup is more closely aligned with normal steady-state operation and includes allowances for high enough temperatures that concerns for condensation are addressed.

Our understanding of facility equipment operations is there are four distinct, mutually-exclusive conditions or periods: *Startup*, *steady-state*, *malfunction*, and *shutdown*. *Steady-state* occurs nearly 99% of the operating periods, while *startup*, *malfunction*, and *shutdown* happen the remainder of the time. EPA has not proposed a definition for *steady-state*, and NC DAQ's view is EPA has too narrowly defined *startup* to be the period between cold start and *steady state*.

Under the EPA proposed definition of *startup*, process and emission control equipment have not reached stable, constant conditions at the end of the *startup* period, as equipment operating temperatures have not reached a suitable level -- for emission controls to reach *steady-state* and perform as intended -- after achieving only 25% load. For example, the manufacturer's recommended operating procedure for common air pollution control equipment (APCE, such as baghouses, electrostatic precipitators, cyclones, selective catalytic reduction, etc.) is to eliminate, or at least minimize, exposure to condensation. This means operators need to wait until the gas temperature is above a certain minimum temperature (e.g., dew point) before subjecting the equipment to the gas stream or before energizing emission controls. If operators prematurely

subject control equipment to temperatures below the dew point, then condensation will occur and damage the equipment, leading to preventable equipment malfunction.

The term *steady-state* is normally defined as "a condition in which the properties of any part of a system are constant," or "a condition of a physical system or device that does not change over time." *Steady-state* occurs after startup, before shutdown, and outside of malfunction. On one hand, EPA requires facility personnel to follow manufacturer's recommendation for equipment operation. On the other, EPA defines startup in such a way as to encourage facility personnel to deviate from manufacturer's recommendation and short-circuit the startup period, thereby increasing the opportunity of equipment *malfunction*, the adverse condition facilities strive to minimize.

EPA could follow the same common-sense approach it applies for emission monitors in which it allows reasonable time for temperatures to reach appropriate levels after *startup* and before producing valid data. It does not consider emission monitoring data valid until after monitoring equipment has heated and reached *steady-state*, nor does it require monitors to produce valid data immediately after a cold start. Accordingly, EPA could define startup as the reasonable length of time after cold start and before steady-state so as not to induce malfunctions.

Response: See the responses to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46, regarding 25% load SS definition threshold, and comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5, regarding use of manufacturer's specifications. See the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 5, regarding maximum time limit for startup/shutdown.

Commenter Name: Jennifer Youngblood

Commenter Affiliation: National Tribal Air Association

Document Control Number: EPA-HQ-OAR-2002-0058-3667-A2

Comment Excerpt Number: 18

Comment: Perhaps more significantly than these combustion device issues is the variability imposed by process considerations. Often startup and shutdown timing is set by the process demands they serve. For instance, a boiler or process heater often has its time at <25% firing set by the rate at which the process it serves starts up or shuts down. Clearly, a boiler or process heater cannot just crank up to high operating rate unless there is demand for the steam or process heat it provides. Similarly, low levels of steam or process heat are often need to continue while process equipment is shutdown and de-inventoried. For these reasons, the time between initial light-off of a boiler or process heater and 25% firing and between 25% firing and total shutdown (all heat input is stopped) is highly variable. Any limit on the duration of these activities will certainly result in situations where the time limit is exceeded and units will become subject to numerical emission limits that cannot be met at such low operating rates.

Response: See response to DCN EPA-HQ-OAR-2002-0058-3534-A1, Excerpt No. 46, regarding 25% load SS definition threshold, and DCN EPA-HQ-OAR-2002-0058-3659-A2, Excerpt No. 5, regarding use of manufacturer's specifications. See response to DCN EPA-HQ-OAR-2002-0058-3465-A1, Excerpt No. 5 regarding maximum time limit for startup/shutdown.

Commenter Name: Robin Mills Ridgway
Commenter Affiliation: Purdue University
Document Control Number: EPA-HQ-OAR-2002-0058-3668-A2
Comment Excerpt Number: 4

Comment: Purdue believes the following types of concepts could be used as startup and shutdown definitions (76 FR 80615). being indicative of a boiler or process heater reaching the end of a startup period (the beginning of a startup would occur with first introduction of fuel with combustion in the furnace):

- Boiler or process heater firing its primary fuel for a period of time adequate to provide stable and non- interrupted fuel flow, stable and controlled air flows, and adequate operating temperatures to allow proper fuel drying and air preheat as applicable.
- Emissions controls in service with operating parameters such as flow rates and temperatures being controlled and stable.
- Boiler or process heater supplying steam or energy output to a common header system or energy user(s) at normal operating conditions including pressure, temperature, and above minimum operational output flow rate, as applicable to the unit.
- Similarly, Purdue believes the following types of concepts could be used as being indicative of a boiler beginning a shutdown period (the end of a shutdown would occur with the cessation of combustion of any fuel in the furnace):
- Cessation of introduction of the last remaining primary fuel to the furnace, whether or not a supplemental support fuel is being used.
- Cessation of emissions control system sorbent or other reagent injection.
- Lowering the fuel firing rate to the point that automatic control is no longer effective or possible.
- Lowering of operating rates to the point that emissions control systems no longer can be controlled or be effective due to low flow rates, low temperatures, or other issues.
- Lowering boiler or process heater output to the point that steam or energy output no longer meets operational required conditions of pressure, temperature, or flow.
- Boiler and process heater owners/operators should establish specific operating conditions and parameters defining startup and shutdown in standard operating procedures for each affected unit so that it is clear when each unit is in either startup or shutdown mode. Procedures should also be used to guide operations purposefully through startup or shutdown periods so that protracted periods in startup or shutdown mode beyond that envisioned in the procedures are avoided. Each startup and shutdown should be documented relative to elapsed time and timing of actions prescribed in the procedure so that problems are effectively identified and corrected in a timely manner.

Response: See the responses to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46, regarding 25% load SS definition threshold, and comment EPA-HQ-OAR-2002-0058-3659-A2,

excerpt 5, regarding use of manufacturer's specifications. See the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 5, regarding maximum time limit for startup/shutdown.

Commenter Name: Pat Dennis

Commenter Affiliation: Archer Daniels Midland Company

Document Control Number: EPA-HQ-OAR-2002-0058-3670-A2

Comment Excerpt Number: 10

Comment: 25% of rated load is not an indication of the end of startup or the beginning of a shutdown for a large fluidized bed boiler. Minimum stable loads for large fluidized bed boilers are approximately 50% of rated load. The purpose of a startup is to get a boiler stabilized and on line as quickly as possible without jeopardizing the safety of personnel or risking damage to the boiler. Also, startups may commonly require the curing of refractory. This process cannot be shortened without risking damage to new refractory. For these reasons, EPA should allow the defining of startup and shutdown periods to be done on a case by case basis and not attempt to regulate the time period required for startup.

Response: See the responses to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46, regarding 25% load SS definition threshold, and comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5, regarding use of manufacturer's specifications. See the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 5, regarding maximum time limit for startup/shutdown.

Commenter Name: Elizabeth McMeekin

Commenter Affiliation: PPG Industries, Inc

Document Control Number: EPA-HQ-OAR-2002-0058-3778-A1

Comment Excerpt Number: 18

Comment: The following types of concepts could be used as being indicative of a boiler or process heater reaching the end of a startup period (the beginning of a startup would occur with first introduction of fuel with combustion in the furnace):

- Boiler or process heater firing its primary fuel for a period of time adequate to provide stable and non-interrupted fuel flow, stable and controlled air flows, and adequate operating temperatures to allow proper fuel drying and air preheat as applicable.
- Emissions controls in service with operating parameters such as flow rates and temperatures being controlled and stable.
- Boiler or process heater supplying steam or energy output to a common header system or energy user(s) at normal operating conditions including pressure, temperature, and above minimum operational output flow *rate*, as applicable to the unit.

Response: See the responses to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46, regarding 25% load SS definition threshold, and comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5, regarding use of manufacturer's specifications. See the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 5, regarding maximum time limit for startup/shutdown.

Commenter Name: Elizabeth McMeekin
Commenter Affiliation: PPG Industries, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-3778-A1
Comment Excerpt Number: 19

Comment: The following types of concepts could be used as being indicative of a boiler or process heater beginning a shutdown period (the end of a shutdown would occur with the cessation of combustion of any fuel in the furnace):

- Cessation of introduction of the last remaining primary fuel to the furnace, whether or not a supplemental support fuel is being used.
- Cessation of emissions control system sorbent or other reagent injection.
- Lowering the fuel firing rate to the point that automatic control is no longer effective or possible.
- Lowering of operating rates to the point that emissions control systems no longer can be controlled or be effective due to low flow rates, low temperatures, or other issues.
- Lowering boiler or process heater output to the point that steam or energy output no longer meets operational required conditions of pressure, temperature, or flow.

Response: See the responses to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46, regarding 25% load SS definition threshold, and comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5, regarding use of manufacturer's specifications. See the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 5, regarding maximum time limit for startup/shutdown.

Commenter Name: Lorraine Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1
Comment Excerpt Number: 117

Comment: However, ACC does believe that if the startup and shutdown definitions are finalized with a load threshold, EPA should provide clarity for what requirements units operating in standby mode at loads less than that threshold (e.g., 25 percent) must meet. ACC believes that work practices are appropriate for units operating in standby mode at very low load. Boilers or process heaters operating in a standby mode would typically be combusting clean burning liquid or gaseous fuels during those periods.

Response: The EPA believes that the revised definitions adequately address units operating in standby mode and that such units should not be exempt from the startup and shutdown provisions of the final rule because??

See the responses to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46, regarding 25% load SS definition threshold, and comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5, regarding use of manufacturer's specifications.

Commenter Name: Russell A. Wozniak
Commenter Affiliation: The Dow Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3449-A1
Comment Excerpt Number: 37

Comment: Dow requests that EPA consider revising the startup/shutdown proposed rule definitions to address variability in combustion unit operational use. Dow operates some combustion units in a standby (operational readiness) mode for extended periods of time at less than 25% load. Operating some boilers in stand-by mode is necessary at larger complex petrochemical facilities and allows for expeditious ramping up of combustion units to provide process operating continuity. When standby mode is reached, combustion unit operating characteristics are stable (e.g. combustion zone flame/oxygen level) and the emissions are insignificant. For combustion units that are subject to a Table 1 or 2 emission limit and only burn Gas 1 fuel/Other Gas 1 fuel during startup, the rule should provide that these units are also exempt from startup provisions. Dow believes that a startup load criteria of 5% of maximum design heat input for these types of combustion units is practical and achievable, but that the criteria should be defined within a range of 5 to 25% load by the owner/operator. *Startup means the period between the state of no combustion in the unit to the period where the unit first achieves stable load conditions defined by the owner/operator (typically between 5 percent and 25 percent load).*

Response: See the response to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 117 regarding standby mode and startup and shutdown provisions.

Commenter Name: Eric Guelker, Alliant Energy Corporate Services, Inc.
Commenter Affiliation: Interstate Power and Light Company (IPL) and Wisconsin Power and Light Company (WPL), Alliant Energy Corp.
Document Control Number: EPA-HQ-OAR-2002-0058-3492-A1
Comment Excerpt Number: 9

Comment: Alliant Energy supports exempting periods of Startup and Shutdown (S&S) from compliance with the MACT emissions limitations. However, we believe that EPA's S&S definitions require additional clarification and operational flexibility. In particular, it may not be readily apparent when a unit has first achieved or last operated at 25% load. This is especially the case for smaller auxiliary units that support larger facility operations. In this instance, we believe that EPA should allow affected sources to use manufacturer's specifications to define S&S procedures that would define appropriate factors to monitor (rather than load) or establish a time-based approach.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 117 regarding standby mode and startup and shutdown provisions.

Commenter Name: Paul Noe
Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.
Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1
Comment Excerpt Number: 16

Comment: We do believe should EPA finalize the startup and shutdown definitions with a load threshold, the requirements for units operating in standby mode at loads less than that threshold (e.g., 25 percent) must be made clear. We believe that work practices are appropriate for units operating in standby mode at very low load. These units would typically be firing clean burning liquid and gas in standby mode.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 117 regarding standby mode and startup and shutdown provisions.

Commenter Name: Richard Krock

Commenter Affiliation: The Vinyl Institute

Document Control Number: EPA-HQ-OAR-2002-0058-3526-A1

Comment Excerpt Number: 16

Comment: The Agency's approach does not appear to address boilers that operate in standby mode for long stretches of time. There are critical operational requirements that apply to these standby boilers, and it would be inefficient and ultimately result in increased emissions if they had to be completely shutdown and then restarted during these periods in order to comply with the proposed rule. For example, the sudden loss of steam in a PVC plant can have the following consequences:

- Higher emissions of VOC compounds from the slurry resin process, which relies upon steam strippers to reduce the concentrations of residual vinyl chloride and other compounds from PVC slurry produced in the reactors;
- Increased emissions from the process wastewater which relies on steam strippers to remove VOC before atmospheric exposure of wastewater; and
- Production of off-grade product, which may have to be disposed of as a waste if a buyer is not available.

The VI requests that EPA revise the definitions to allow for continued use of these boilers as well.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 117 regarding standby mode and startup and shutdown provisions.

Commenter Name: Elizabeth McMeekin

Commenter Affiliation: PPG Industries, Inc

Document Control Number: EPA-HQ-OAR-2002-0058-3778-A1

Comment Excerpt Number: 21

Comment: If the startup and shutdown definitions are finalized with a load threshold, EPA should provide clarity for what requirements units operating in standby mode at loads less than that threshold (e.g., 25 percent) must meet. We believe that work practices are appropriate for units operating in standby mode at very low load. Boilers or process heaters operating in a standby mode would typically be combusting clean burning liquid or gaseous fuels during those periods.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 117 regarding standby mode and startup and shutdown provisions.

Commenter Name: Bruce W. Ramme

Commenter Affiliation: Wisconsin Electric Power Company (WE Energies)

Document Control Number: EPA-HQ-OAR-2002-0058-3452-A1

Comment Excerpt Number: 13

Comment: To account for site-specific variability of boiler design and/or fuel specifications, We Energies requests that EPA include an option for affected units to develop a site-specific startup and shutdown plan for subsequent approval by the state permitting authority. This option would be implemented through the construction/operation permitting process, at the same time that the IB-MACT rule requirements are also being incorporated into an affected unit's permit. The permit would include conditions requiring the affected unit to develop a startup and shutdown plan that defines those periods of operation. The state permitting authority would approve the plan prior to the affected unit being authorized to apply the proposed work practice standard during those periods of boiler operation.

Response: The EPA is setting standards that apply at all times, including periods of startup and shutdown. With such standards in place, sources will need to plan for and achieve compliance during startup and shutdown and during malfunctions, so there is no reason to require sources to develop SSM plans.

Commenter Name: Dakota Gasification Company Great Plains Synfuels Plant

Commenter Affiliation: David W. Peightal

Document Control Number: EPA-HQ-OAR-2002-0058-3424

Comment Excerpt Number: 14

Comment: The SSM Plan should address the requirement to minimize emission as low as practical during these events, in accordance with the general provisions.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3452-A1, excerpt 13, regarding site-specific SS plans.

Commenter Name: Kevin G. Desharnais, Attorney, Mayer Brown LLP

Commenter Affiliation: United States Sugar Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3496-A1

Comment Excerpt Number: 17

Comment: EPA's proposed definitions specify that only the periods of time between a complete shutdown of a unit (no fuel being combusted) and the time that a unit first reaches 25 percent load qualify as startup, and only the periods of time between 25 percent load and a complete shutdown (no fuel being combusted) qualify as shutdown. Whether 25 percent load is an appropriate determinant for startup and shutdown will vary from boiler to boiler. In the case of bagasse boilers, the 25 percent load limitation is particularly inappropriate, since stable operating conditions may not be reached until the boiler achieves 60 percent load. The 25 percent load

restriction constitutes an arbitrary limitation, and startup and shutdown should instead be defined in accordance with good operating practices for any particular boiler. The minimum stable operating load that defines startup and shutdown, and the proper procedures to follow during startup and shutdown, can be included in a site-specific operating plan.

Response: See the responses to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46, regarding 25% load SS definition threshold, and comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5, regarding use of manufacturer's specifications. See the response to comment EPA-HQ-OAR-2002-0058-3452-A1, excerpt 13, regarding site-specific SS plans.

Commenter Name: LESLIE SUE RITTS

Commenter Affiliation: National Environmental Development Association's Clean Air Project (NEDA/CAP)

Document Control Number: EPA-HQ-OAR-2002-0058-3529-A1

Comment Excerpt Number: 2

Comment: EPA should allow sources to define startup and shutdown based on SSM Plans required under 40 CFR §63.6(e) of the General MACT Provisions. The definition of "startup" and "shutdown" cannot be precisely defined, even for the same unit, because it typically differs depending on the type of unit, fuel, method of delivering and dispersing the fuel in the boiler chamber and ambient air temperature, and other process, operational or maintenance circumstances related to the startup or shutdown. Until there is complete combustion in the firebox or, for example, threshold temperatures are reached on operational and certain air emissions control devices, a unit may have the potential to exceed the emission limits that are applicable during continuous operations. It was appropriate therefore for EPA to establish work practice standards for startups and shutdowns. It is *inappropriate* for the Agency to define these terms relative to the load-carrying capability of any boiler since that is not necessarily relevant to the other conditions listed previously. Moreover, it is completely arbitrary for EPA to pick 25 % of full load as a definition, and in fact the agency offers no basis in the proposal for defining startup or shutdown as ramping up or down to 25% of full load. Importantly, and given that EPA has established CO limits based on data outside of start-up and shut-down periods, EPA should recognize that at lower loads which occur during start-ups and shut-down periods emissions of CO may be substantially higher than at the normal operating loads. For this reason, in the original Boiler MACT rule, the CO limit applied only when the load was greater than 50%. EPA has made no reasoned accounting of these circumstances in proposing an arbitrary 25% cut-off for normal non-start-up or shut-down operation.

Response: See the responses to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46, regarding 25% load SS definition threshold, and comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5, regarding use of manufacturer's specifications. See the response to comment EPA-HQ-OAR-2002-0058-3452-A1, excerpt 13, regarding site-specific SS plans.

Commenter Name: LESLIE SUE RITTS

Commenter Affiliation: National Environmental Development Association's Clean Air Project (NEDA/CAP)

Document Control Number: EPA-HQ-OAR-2002-0058-3529-A1

Comment Excerpt Number: 4

Comment: In view of NEDA/CAP's concern that it would be unreasonable for EPA to establish "one" definition of "startup" or "shutdown," we would suggest that a boiler operator define these terms under its SSM plan, required under the MACT General Provisions. *See* 40 CFR §63.6(e). That would allow boiler operators to distinguish "startup" or "shutdown" from operations that are simply following load, and it would be based on safety and good engineering practice and experience with existing equipment based on the type of boiler, fuel, operations, etc. Alternatively, or in conjunction with the boiler tune-ups required by the Final MACT Rule, "startup" or "shutdown" definitions can be established for a unit in the facility's SSM plan. EPA or the public can request review of this document if there is actually a basis to believe that an operator is circumventing compliance with the ICI MACT by "cycling in and out of startup or shutdown."

Response: See the response to comment EPA-HQ-OAR-2002-0058-3452-A1, excerpt 13, regarding site-specific SS plans.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 49

Comment: Boiler owners/operators should establish specific operating conditions and parameters defining startup and shutdown in standard operating procedures for each affected unit so that it is clear when each unit is in either startup or shutdown mode. Procedures should also be used to guide operations purposely through startup or shutdown periods so that protracted periods in startup or shutdown mode beyond that envisioned in the procedures are avoided. Each startup and shutdown should be documented relative to elapsed time and timing of actions prescribed in the procedure so that problems are effectively identified and corrected in a timely manner.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3452-A1, excerpt 13, regarding site-specific SS plans.

Commenter Name: J. Michael Geers

Commenter Affiliation: Duke Energy

Document Control Number: EPA-HQ-OAR-2002-0058-3543-A1

Comment Excerpt Number: 7

Comment: In the proposal, EPA attempts to place all boilers into the same category using a 25% load as the threshold for ending a startup or beginning a shutdown. This distinction, however, is not always clear cut because boilers have a wide variety of fuel type, furnace and boiler designs (combustion method), and demand requirements and operating methodologies. Some specific examples include the following:

Solid fuel fired boilers, particularly pulverized, cyclone, biomass and fluid bed units, have higher minimum stable loads than do oil and gas fired units. This is because these units require a higher minimum fuel flow to load to prevent fires and/or explosions in the pulverizers, burner lines, burners, and in the furnace. A higher fuel flow keeps the conditions in the pulverizers and burner lines in a “fuel rich” environment above the higher level of explosion. In fluid bed units, a minimum firing rate is required just to ensure that the fire does not continue to go out at low loads.

- Oil and gas fired units have more capability to fire at low levels for longer periods of time. For some units, this can be accomplished by simply substituting an oil gun with a smaller capacity sprayer tip.
- Some facilities with solid fuel boilers have substantial steam load fluctuations such that they operate in a hot standby mode. In this standby mode, the boiler is “banked”, which means the bed of fuel is hot and burning very slowly, but no significant steam is being produced. No combustion air is being supplied. All that it takes to bring the boiler on line is to begin combustion air to increase the combustion rate. Depending upon conditions, boilers can be in “banked” mode for hours to several days.
- Solid fuel units, particularly older anthracite units, will have a fire on the grate for several days to allow for slow heat-up of the refractory and other critical metal components. The slow heat up rate is necessary to prevent material damage to the unit. No steam is being produced during the warm-up period.
- Some facilities may have oil fired boilers that are sized for winter heating loads, but have excess capacity to meet summer steam loads. Often, a unit may cycle on and off because the facility steam load is below minimum firing rate for the unit.
- Biomass units have their own particular operating requirements due to their furnace design and fuel type.

Duke Energy has limited experience with units other than those that are solid fuel fired. However, based on its experience, Duke Energy does believe that a 25% load factor is an appropriate cut off for pulverized, cyclone, biomass, and fluid bed solid fuel fired industrial boilers for both start-up and shutdown. Duke Energy also believes that EPA should not include a maximum time in the startup and shutdown definitions. Sources covered by the rule are highly variable and the amount of time needed for startup and shutdown are different depending on the specific unit. In the operation of its units, Duke Energy specifies minimum operating loads that are consistently above 25%. Once a pulverized coal unit is started, it will ramp up load steadily from low loads to its minimum operating load (greater than 25%) without delay. As a result, while sources could pick different loads in the 10% to 40% range, Duke Energy believes that 25% is a good compromise value and that it should be based on either heat input or steam flow. In the event that an individual source seeks a higher value based on operating safety criteria, that source should approval from its local permitting authority.

Response: See the responses to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46, regarding 25% load SS definition threshold, and comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5, regarding use of manufacturer’s specifications. See the response to comment EPA-HQ-OAR-2002-0058-3452-A1, excerpt 13, regarding site-specific SS plans.

Commenter Name: Annabeth Reitter
Commenter Affiliation: NewPage Corporation
Document Control Number: EPA-HQ-OAR-2002-0058-3662-A2
Comment Excerpt Number: 10

Comment: EPA has defined startup and shutdown as follows:

- Startup means the period between the state of no combustion in the unit to the period where the unit first achieves 25 percent load (Le., a cold start).
- Shutdown means the period that begins when a unit last operates at 25 percent load and ending with a state of no fuel combustion in the unit.

The conditions EPA has designated for startup and shutdown will be problematical for our units. For example, the design of our circulating Fluidized Bed (CFB) boilers provides many advantages for efficient combustion; however, these boilers do not have a conventional startup curve. The CFB boilers at one of our facilities are started on oil and bed material is introduced into the furnace gradually to build a properly classified bed. Solid fuel is introduced when temperatures are met however the proper classification of the bed is still ongoing. Due to the uniqueness of these units we have had to negotiate alternate startup/shutdown requirements with our State permit authority and these procedures have been incorporated into our permit. We are allowed a 24/36 hour window without opacity limitation to achieve full startup or shutdown. This allows for the introduction/removal of bed material and a proper startup/shutdown curve. These conditions are a result of properly managing and operating the CFBs but also take into account facility specific conditions. These units share a common stack so that startup/shutdown activity in one unit may be ongoing while the other continues to run. In this situation compliance with an opacity standard as a surrogate for PM₁₀HAPs may be a difficult situation and may not be achievable. As part of the startup/shutdown work practice provisions, EPA needs to adequately address this situation for sources that share a common stack. Lastly, not unique to CFBs, after internal maintenance there is commonly a refractory cure that occurs for 24 or 36 hours. This is typically at lower loads, but may approach or exceed of 25% heat input at the end of the cure prior to full startup.

The 25% load thresholds are arbitrary and attempt to place all boilers in the same basket. Due to varying boiler designs, fuel type, combustion method and operating methodologies, this threshold for identifying startup and shutdown conditions is not workable. EPA should abandon the 25% load threshold for startup and shutdown and address startup and shutdown through only the use of work practices and let the sources determine how to acceptably define startup and shutdown for their units. This could be handled through the use of a startup and shutdown plan.

Response: See the responses to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46, regarding 25% load SS definition threshold, and comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5, regarding use of manufacturer's specifications. See the response to comment EPA-HQ-OAR-2002-0058-3452-A1, excerpt 13, regarding site-specific SS plans.

Commenter Name: Elizabeth McMeekin
Commenter Affiliation: PPG Industries, Inc

Document Control Number: EPA-HQ-OAR-2002-0058-3778-A1

Comment Excerpt Number: 20

Comment: Boiler and process heater owners/operators should establish specific operating conditions and parameters defining startup and shutdown in standard operating procedures for each affected unit so that it is clear when each unit is in either startup or shutdown mode. Procedures should also be used to guide operations purposely through startup or shutdown periods so that protracted periods in startup or shutdown mode beyond that envisioned in the procedures are avoided. Each startup and shutdown should be documented relative to elapsed time and timing of actions prescribed in the procedure so that problems are effectively identified and corrected in a timely manner.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3452-A1, excerpt 13, regarding site-specific SS plans.

Commenter Name: Chris M. Hobson

Commenter Affiliation: Southern Company

Document Control Number: EPA-HQ-OAR-2002-0058-3520-A1

Comment Excerpt Number: 9

Comment: While Southern Company supports the inclusion of work practice standards during startup and shutdown, we believe that the definitions and work practices should be modified to better account for each unit's safety and good engineering practices for startup and shutdown. Our historical operating experience with coal and oil-fired power plants has shown that each unit starts up slightly different depending on the unit design and applicable emission control devices. For many plants, all emission control devices are not fully in service by the time 25 percent load is reached. These plants would be at risk of exceeding the 30-day rolling average simply because good engineering and safety practice did not allow the emission control device to be online during EPA's defined startup period. For a biomass-fired boiler, many control devices, including ESPs, baghouses, or sorbent injections, should be bypassed or used in a limited manner until startup fuel, such as oil, is removed from service. To reduce the risk of fire and equipment fouling from oil carry-over, for example, electrostatic precipitators (ESPs) and baghouses are gradually brought into service, starting with just a small section at a time. For the Plant Mitchell biomass conversion, the startup fuel would not be removed from service until the unit reaches about 50 percent load. In fact, the active introduction of biomass to the boiler may not begin until the unit reaches 20 to 25 percent load. During the transition from startup fuel to 100 percent biomass-firing, which can take several hours, the unit may also experience higher combustion emissions, such as CO, until the unit stabilizes on 100 percent biomass. Startup procedures, time periods, and loads can be highly unit-specific. Thus, EPA should allow each source to work with its relevant permitting authority to develop a site specific startup definition and work practice standard that is tailored for the unique characteristics, control devices, and safety practices of each plant.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3452-A1, excerpt 13, regarding site-specific SS plans. See the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 5, regarding maximum time limit for startup/shutdown.

Commenter Name: Stephen E. Woock
Commenter Affiliation: Weyerhaeuser Company
Document Control Number: EPA-HQ-OAR-2002-0058-3523-A1
Comment Excerpt Number: 3

Comment: However, the current re-proposal would create untenable and infeasible requirements by defining these periods with a single threshold of 25% operating load. As detailed in our trade group comments, this single threshold approach fails to account for the variety of equipment and circumstances that make startup and shutdown procedures unique to a facility and combustion unit. Site-specific plans and approaches must be allowed for safety, process and operational reasons.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3452-A1, excerpt 13, regarding site-specific SS plans. See the responses to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46, regarding 25% load SS definition threshold, and comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5, regarding use of manufacturer's specifications.

Commenter Name: John M. Cullen
Commenter Affiliation: Masco Corporation
Document Control Number: EPA-HQ-OAR-2002-0058-3661-A2
Comment Excerpt Number: 9

Comment: Masco opposes EPA's proposed 25% load threshold for startup and shutdown. Such an arbitrary load requirement fails to take into account that some boilers may not achieve steady-state operations at 25% load and others may achieve steady-state operations at less than 25% load on startup. Instead, the regulated source should determine when a startup or shutdown ends or begins based upon site-specific data to be included in a site-specific plan.

Response: See the responses to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46, regarding 25% load SS definition threshold, and comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5, regarding use of manufacturer's specifications. See response to comment EPA-HQ-OAR-2002-0058-3452-A1, excerpt 13, regarding site-specific SS plans.

Commenter Name: Elizabeth McMeekin
Commenter Affiliation: PPG Industries, Inc
Document Control Number: EPA-HQ-OAR-2002-0058-3778-A1
Comment Excerpt Number: 17

Comment: EPA has included a threshold of 25 percent load in its definition of startup and shutdown. Some units have a minimum stable operating load that is higher than 25 percent (e.g., stable operation for a stoker boiler may not be reached until 60 percent load). Therefore, EPA should revise the startup definition to allow facilities to determine the minimum stable operating load on a unit-specific basis and include the minimum stable operating load that defines startup and shutdown and the proper procedures to follow during startup and shutdown in a site-specific plan.

Response: See the responses to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46, regarding 25% load SS definition threshold, and comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5, regarding use of manufacturer's specifications. See response to comment EPA-HQ-OAR-2002-0058-3452-A1, excerpt 13, regarding site-specific SS plans.

Commenter Name: Douglas A. McWilliams

Commenter Affiliation: American Municipal Power

Document Control Number: EPA-HQ-OAR-2002-0058-3685-A2

Comment Excerpt Number: 16

Comment: The proposed boiler operator training requirements are unnecessary and serve only to create additional recordkeeping and reporting requirements and increase the cost of the rule. The Proposed Rule already requires boiler operators to (*f at all times, operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions.*" To satisfy this condition, and to operate the boiler in a safe manner, boiler operators receive appropriate training. Adding a training work practice standard adds nothing to the rule except additional recordkeeping and reporting requirements that do not serve any beneficial environmental purpose.

These additional recordkeeping and reporting requirements impose particular hardship on small municipal utilities that do not have personnel dedicated solely to environmental compliance. Each additional recordkeeping and reporting obligation created by the Boiler MACT rule must be carried out by boiler operators in addition to their general operating duties. Superfluous recordkeeping and reporting obligations that serve no environmental purpose should be eliminated wherever possible to avoid unnecessary compliance costs that could be better allocated to meaningful emission reduction investments. This is particularly the case here, where EPA has offered no reason for abandoning its previous work practice approach.

Response: We recognize the concerns of the commenter and agree that the training records mentioned by the commenter do not have an impact on human health or the environment. As such, we have removed the operator training requirements from this rule, consistent with the procedures in the recently promulgated MATS rule, 40 CFR part 63, subpart UUUUU.

Commenter Name: M.L. Steele

Commenter Affiliation: CraftMaster Manufacturing, Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3814-A1

Comment Excerpt Number: 22

Comment: §63.7555(i) Maintain records of operator training for start-up/ shutdown procedures for each start-up/ shutdown event. Operator training should not have to be repeated more frequently than once per year.

Response: See the response to comment EPA-HQ-OAR-2002-3685-A2, excerpt 16, regarding SS recordkeeping and reporting requirements.

Commenter Name: Douglas A. McWilliams
Commenter Affiliation: American Municipal Power
Document Control Number: EPA-HQ-OAR-2002-0058-3685-A2
Comment Excerpt Number: 14

Comment: Additional Work Practice Standards During Startup and Shutdown Are Unnecessary

The additional work practices EPA has proposed create unnecessary recordkeeping and reporting burdens that increase costs without any additional environmental benefits. The duty to minimize emissions consistent with recommended procedures would necessarily include adherence to good combustion practices. Boiler operators have a business incentive to operate their boilers as efficiently as possible. Furthermore, optimal O₂ concentrations will vary by boiler and design. Many existing units, and all of AMP members' generating units, were constructed prior to 1970, and do not have manufacturer's instructions indicating optimal O₂ concentrations. "Similar units" that are appropriate benchmark for optimal combustion than a numeric O₂ concentration that may or may not represent the most efficient combustion for that unit.

Response: See the responses to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46, regarding 25% load SS definition threshold, and comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5, regarding use of manufacturer's specifications. See the response to comment EPA-HQ-OAR-2002-3685-A2, excerpt 16, regarding SS recordkeeping and reporting requirements.

Commenter Name: Michael D. Wendorf
Commenter Affiliation: FMC Corporation
Document Control Number: EPA-HQ-OAR-2002-0058-3453-A1
Comment Excerpt Number: 11

Comment: Based upon many years of experience operating both PC and stoker coal boilers, FMC requests the EPA to consider a maximum allowed startup time of 24 hours. Boilers restarted after major overhauls may require several hours to shake down systems that have been repaired, installed or replaced. During this period it is essential to keep boiler loads low in order to minimize impacts to the boilers and to the rest of the facility. Interactions between repaired, installed or replaced systems cannot be tested prior to first startup after an extended boiler overhaul. Pollution control equipment such as an electrostatic precipitator (ESP) is sensitive to a minimum flue gas temperature before being capable of being energized and operating at an acceptable level of collection efficiency. A deliberate startup can require several hours for the flue gas temperature to reach that critical minimum temperature.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 5, regarding maximum time limit for startup/shutdown.

Commenter Name: Michael D. Wendorf
Commenter Affiliation: FMC Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3453-A1

Comment Excerpt Number: 12

Comment: With respect to a reasonable shutdown period, stoker boilers offer an option not afforded to PC boilers, that being the ability to 'bank' the fire during extended periods of low steam demand rather than to conduct a complete shutdown. This flexibility allows quicker response to resumptions in increased steam demands, places less stress on the boiler than a shutdown/startup sequence, and can result in lower overall emissions than a cold restart. Therefore, FMC requests EPA to consider a maximum shutdown period of 24 hours for stoker boilers.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 5, regarding maximum time limit for startup/shutdown.

Commenter Name: Traylor Champion

Commenter Affiliation: Georgia-Pacific LLC (GP)

Document Control Number: EPA-HQ-OAR-2002-0058-3465-A1

Comment Excerpt Number: 9

Comment: Insurance companies and regulatory agencies require that boiler safety systems be functionally tested on a routine basis. These functionality tests are typically conducted when the boilers are being shut down for outages so that any problems can be addressed during the outage. If any repairs, maintenance or upgrades are made to the burner management system during an outage, additional functionality tests are performed during startup to insure that there were no inadvertent changes made that negatively affect the performance of the safety systems. These tests are essential to the safe operation of the boilers and they can significantly extend the time required for shutdown/startup.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 5, regarding maximum time limit for startup/shutdown.

Commenter Name: Traylor Champion

Commenter Affiliation: Georgia-Pacific LLC (GP)

Document Control Number: EPA-HQ-OAR-2002-0058-3465-A1

Comment Excerpt Number: 10

Comment: Some degree of refractory repair/replacement is a common element in many, if not most, boiler outages. The repair/replacement materials generally require an extended cure-out period upon start-up to avoid cracks, spalling, etc. caused by moisture exiting the material. The cure-out time will be variable based on the type and extent of refractory material replaced in a given outage and may not be known until internal.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 5, regarding maximum time limit for startup/shutdown.

Commenter Name: Traylor Champion

Commenter Affiliation: Georgia-Pacific LLC (GP)

Document Control Number: EPA-HQ-OAR-2002-0058-3465-A1

Comment Excerpt Number: 11

Comment: GP has a significant number of boilers that will be impacted by this regulation. These boilers have various designs, fuel types, steam temperature/pressure, ages, refractory designs and physical sizes, all factors that will impact the length of time required for startup and shutdown. We have units that can startup within a matter of hours, while others take upwards of two-days to properly heat and bring online. These examples demonstrate the wide variation in time required to properly and safely start an industrial boiler.

The final rule should not force GP's boiler operators to decide between complying with an emissions limit and protecting fellow employees and the integrity of the equipment. Therefore, we urge EPA not to include arbitrary time limits on startup and shutdown for boilers in general or one that would be consistently applicable to an individual boiler in all circumstances.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 5, regarding maximum time limit for startup/shutdown.

Commenter Name: Dirk J. Krouskop

Commenter Affiliation: MeadWestvaco Corporation (MWV)

Document Control Number: EPA-HQ-OAR-2002-0058-3493-A1

Comment Excerpt Number: 12

Comment: EPA specifically requests comment on whether a maximum time should be included in the startup and shutdown definitions. We believe that this is not necessary, as safety and proper operation of the boiler and associated equipment dictate the amount of time that is needed for startup and shutdown and vary from unit to unit and site to site.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 5, regarding maximum time limit for startup/shutdown.

Commenter Name: Kevin G. Desharnais, Attorney, Mayer Brown LLP

Commenter Affiliation: United States Sugar Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3496-A1

Comment Excerpt Number: 18

Comment: U.S. Sugar does not believe it is appropriate to try and set a specific time limit on startup or shutdown, as the time necessary for startup and shutdown activities will vary from boiler to boiler. Safety and proper operation of the boiler and associated equipment will dictate the amount of time that is needed for startup and shutdown. The time period for startup and shutdown should likewise be defined in terms of good operating practices for the particular boiler.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 5, regarding maximum time limit for startup/shutdown.

Commenter Name: David A. Buff, Golder Associates Inc.
Commenter Affiliation: Florida Sugar Industry (FSI)
Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1
Comment Excerpt Number: 51

Comment: The FSI believes that it is not appropriate to include a maximum time limit for startup and shutdown periods. The time needed for startup and shutdown will vary from boiler to boiler, depending on site specific circumstances. A maximum time limit also is not necessary because safety and proper operation of the boiler and associated equipment will dictate the amount of time that is needed for startup and shutdown. Overly prescriptive and non-facility-specific requirements can be counterproductive, because they will restrict the operator's ability to troubleshoot and respond to unanticipated events.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 5, regarding maximum time limit for startup/shutdown.

Commenter Name: Lorraine Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1
Comment Excerpt Number: 109

Comment: ICI boilers, like their larger EGU counterparts, require an extended period of startup during which most, if not all, equipment in the boiler and pollution control systems are not operating in their normal condition. This extended startup period, which can range from a few to many hours depending on unit design and emissions control systems in place, is required due to equipment integrity concerns, limitations of the technologies, or safety concerns.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 5, regarding maximum time limit for startup/shutdown.

Commenter Name: Paul Noe
Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.
Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1
Comment Excerpt Number: 13

Comment: EPA requests comment on whether a maximum time should be included in the startup and shutdown definitions. We believe that this is not necessary, as safety and proper operation of the boiler and associated equipment dictate the amount of time that is needed for startup and shutdown and vary from unit to unit and site to site. Overly prescriptive and non-facility-specific requirements can actually be counterproductive, restricting the operators' flexibility in a way that hampers their ability to troubleshoot or respond to an event, or that compromises safety.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 5, regarding maximum time limit for startup/shutdown.

Commenter Name: Sarah Hedrick
Commenter Affiliation: Verso Paper Corp.
Document Control Number: EPA-HQ-OAR-2002-0058-3537-A2
Comment Excerpt Number: 7

Comment: Section 63.7550 (c)(14) creates an unnecessary regulatory burden by requiring facilities to semiannually report the percentage concentration of oxygen in the firebox on an hourly basis throughout each startup or shutdown event, the calendar date and length of each event, and the reason for each event. Again, this reporting requirement is impractical, serves no purpose, and constitutes an unnecessary burden. Each boiler is unique: it has its own startup and shutdown curve, ensuring boiler equipment is not damaged during the startup and shutdown process. Startup and shutdown oxygen concentrations vary from one boiler to the next and are not comparable. Each startup event will differ depending on how warm the boiler is when startup is initiated. Submittal of this data serves no meaningful purpose. This reporting requirement is unreasonable and should be removed from the rule.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 5, regarding maximum time limit for startup/shutdown.

Commenter Name: Jennifer Youngblood
Commenter Affiliation: National Tribal Air Association
Document Control Number: EPA-HQ-OAR-2002-0058-3667-A2
Comment Excerpt Number: 17

Comment: Because of the wide range of designs and operating scenarios for liquid and gas-2 fired BPH, it is impossible to define a time period for startups and shutdowns and therefore none should be specified in the final rule.

On page 80615 of the proposal preamble, EPA requests comment on whether a limit should be placed on the duration of startups and shutdowns. Such a limit cannot reasonably be established, particularly for process heaters, and thus should not be imposed. BPH safety and integrity issues are a reasonable basis for not establishing minimum startup and shutdown times. Protecting refractory from failure typically sets startup time minimums, but this timing can vary significantly depending on whether refractory replacement or repair was performed, the type of refractory, and the equipment design. On shutdown, refractory damage is not as much of a concern but the time it takes for process materials to be removed and, perhaps tubes decoked, vary substantially.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 5, regarding maximum time limit for startup/shutdown.

Commenter Name: Robert Ellerhorst
Commenter Affiliation: Michigan State University
Document Control Number: EPA-HQ-OAR-2002-0058-3674-A2
Comment Excerpt Number: 9

Comment: U.S. EPA is requesting comments to establish maximum time periods for units to operate in startup or shutdown mode. MSU believes that prescribing specific time constraints is not appropriate as procedures are quite specific based upon boiler subcategory, facility operations and fuel types. Startup and shutdown times can vary at each facility due to boiler type and air pollution control equipment. Additionally, MSU believes that it is important to maintain operator flexibility to safely shutdown each unit while allowing for time to troubleshoot and respond to a particular operating event. Nevertheless, MSU is providing U.S. EPA with typical startup and shutdown timeframes for each boiler subcategory at the facility.

MSU operates three (3) pulverized coal (PC) boilers and one (I) circulating fluidized bed (CFB) boiler. All MSU's boilers fire natural gas during periods of startup. From a "cold start", meaning that the boiler has been brought completely offline for a significant period of time, the PC boilers can take 6-8 hours to reach stable operations. MSU's CFB boiler, on the other hand, can take 8-10 hours to become operational on a "cold start".

CFB boilers require longer periods of combustion of fuels prior to startup. The bed itself must be heated to sufficient temperatures with natural gas prior to incorporating solid fuel. Incorporation of solid fuel prior to those temperatures would result in emissions excursions or damage to the boiler.

Similar to periods of startup, CFB boilers require a longer period of time to shutdown the unit. MSU estimates that our PC boilers can be brought off-line (i.e. no combustion and/or steam being generated) within 1-2 hours. However, shutdown procedures for the CFB involve firing natural gas past steam generation to ensure that complete burn out of combustibles occurs in the bed. This process can take up to 8 hours.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 5, regarding maximum time limit for startup/shutdown.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 157

Comment: Proposed §63.7530(h) requires that the NCS contain a certification that "indicates that you employed good combustion practices and you maintained oxygen concentrations as specified by the boiler manufacturer for each startup and shutdown event." We see no need for such a certification since start ups and shutdowns will be occurring forever and recommend this NCS certification requirement be deleted.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 158 regarding NCS certification requirement. See the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 5, regarding maximum time limit for startup/shutdown.

Commenter Name: Douglas A. McWilliams

Commenter Affiliation: American Municipal Power

Document Control Number: EPA-HQ-OAR-2002-0058-3685-A2

Comment Excerpt Number: 18

Comment: It is Inappropriate to Establish Time Limitations on Startup and Shutdown Periods

EPA requested comment on whether a maximum time should be included in the startup and shutdown definitions. Such a requirement is unnecessary, as safety and proper operation of the boiler and associated equipment dictate the amount of time that is needed for startup and shutdown. This time period will vary from unit to unit and from site to site. Safe operation of a coal-fired boiler, for example, may require operators to bring a unit online from a cold start over a period of several days. A non-cold startup, however, may take a period of hours.

EPA's concern that units will operate in perpetual startup or shutdown mode to avoid emission limits is unfounded. Industrial boilers cannot operate in perpetual startup or shutdown mode because this is, by definition, not a stable operating condition. Attempting to operate the unit for extensive periods of time at these levels would cause flame instability as well as increased fuel costs due to inefficient operation. This creates an additional burden on control equipment, which does not operate efficiently until the boiler reaches a stable load. Furthermore, units used for electricity generation can only serve this purpose if they are supplying a steady and sufficient steam flow to the turbine generators. Turbines can become unstable and pose a safety risk if they do not receive sufficient steam. During periods of startup and shutdown, the steam flow is not sufficient to operate the turbine for any significant period of time. Frequent startups and shutdowns also cause excessive wear on the equipment and controls and are not part of standard practice.

EPA has adequate assurances that startup and shutdown will be minimized without setting an arbitrary time limit. The Proposed Rule places a general duty on operators to use good combustion practices for minimizing emissions, which would necessarily include minimizing periods of startup and shutdown. Operators also have a business incentive to operate their boilers in the most efficient manner possible, which includes minimizing periods of startup and shutdown. Overly prescriptive and non-facility-specific requirements would be counterproductive, restricting the operators' flexibility in a way that hampers their ability to troubleshoot or respond to an event, or that compromises safety. EPA does not need to establish a time restriction on startup and shutdown events in light of these facts.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 5, regarding maximum time limit for startup/shutdown.

Commenter Name: Elizabeth McMeekin

Commenter Affiliation: PPG Industries, Inc

Document Control Number: EPA-HQ-OAR-2002-0058-3778-A1

Comment Excerpt Number: 16

Comment: EPA requests comment on whether a maximum time should be included in the startup and shutdown definitions. We believe that this is not necessary, as safety and proper operation of the boiler and associated equipment dictate the amount of time that is needed for startup and shutdown and vary from unit to unit and site to site. Overly prescriptive and non-facility-specific requirements can actually be counterproductive, restricting the operators'

flexibility in a way that hampers their ability to troubleshoot or respond to an event, or that compromises safety.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 5, regarding maximum time limit for startup/shutdown.

Commenter Name: Kevin G. Desharnais, Attorney, Mayer Brown LLP

Commenter Affiliation: United States Sugar Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3496-A1

Comment Excerpt Number: 16

Comment: In the Reconsideration Proposal, EPA retains the work practices approach for startup and shutdown set forth in the Final Rule, and adds new definitions of "startup" and "shutdown" during which the work practices will apply. EPA is soliciting comment on whether a maximum time limit should be established for startup/shutdown, and is requesting information about the appropriate time period for the various unit designs. US Sugar generally supports the application of work practice standards during periods of startup/shutdown. However, the time periods for startup and shutdown can vary across different boilers, and the definitions of startup and shutdown set forth in the Reconsideration Proposal are overly restrictive.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 5, regarding maximum time limit for startup/shutdown.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 113

Comment: EPA requests comment on whether a maximum time should be included in the startup and shutdown definitions. ACC believes that this is not necessary, as safety and proper operation of the boiler and associated equipment dictate the amount of time that is needed for startup and shutdown and vary from unit to unit and site to site. Overly prescriptive and non-facility-specific requirements can actually be counterproductive, restricting the operators' flexibility in a way that hampers their ability to troubleshoot or respond to an event, or that compromises safety.

EPA has included a threshold of 25 percent load in its definition of startup and shutdown. Some units have a minimum stable operating load that is higher than 25 percent (e.g., stable operation for a stoker boiler may not be reached until 60 percent load). Therefore, EPA should revise the startup definition to allow facilities to determine the minimum stable operating load on a unit-specific basis and include the minimum stable operating load that defines startup and shutdown and the proper procedures to follow during startup and shutdown in a site-specific plan.

Response: See the responses to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46, regarding 25% load SS definition threshold, and comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5, regarding use of manufacturer's specifications. See the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 5, regarding maximum time limit for startup/shutdown.

Commenter Name: Lorraine Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1
Comment Excerpt Number: 116

Comment: Boiler and process heater owners/operators should establish specific operating conditions and parameters defining startup and shutdown in standard operating procedures for each affected unit so that it is clear when each unit is in either startup or shutdown mode. Procedures should also be used to guide operations purposely through startup or shutdown periods so that protracted periods in startup or shutdown mode beyond that envisioned in the procedures are avoided. Each startup and shutdown should be documented relative to elapsed time and timing of actions prescribed in the procedure so that problems are effectively identified and corrected in a timely manner.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 5, regarding maximum time limit for startup/shutdown. See the response to comment EPA-HQ-OAR-2002-0058-3452-A1, excerpt 13, regarding site-specific SS plans.

Commenter Name: Paul Noe
Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.
Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1
Comment Excerpt Number: 15

Comment: EPA should also consider that sources need time to properly startup the air pollution control equipment, and this may not always occur before 25 percent load is reached. For example, electrostatic precipitators (ESPs) must typically warm-up to be effective. This practice is necessary to ensure that boilers are started up in a safe manner. Premature starting of this equipment will lead to short term stability problems that could result in unsafe actions and longer term degradation of ESP performance due to fouling, increased chances of wire damage or increased corrosion within the chambers. Vendors providing this equipment make it part of the standard operating procedures. During periods of startup, combustion begins as fuel is introduced and an ESP warms up on a designated curve that could last for several hours. As the control device is heated up additional fuel is added until the ESP meets its design temperature and normal fuel firing is resumed. During such periods it is likely that emissions will exceed the standards proposed and will never be able to recover to meet the average limitations. The definition of startup should require facilities to develop and include a site-specific definition of startup and shutdown and the proper procedures to follow during startup and shutdown in a site-specific plan.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 5, regarding maximum time limit for startup/shutdown. See the response to comment EPA-HQ-OAR-2002-0058-3452-A1, excerpt 13, regarding site-specific SS plans.

Commenter Name: Douglas A. McWilliams
Commenter Affiliation: American Municipal Power

Document Control Number: EPA-HQ-OAR-2002-0058-3685-A2

Comment Excerpt Number: 17

Comment: Startup and Shutdown Definitions Must Be Established on a Site-Specific Basis

EPA has included a threshold of 25 percent load in its definitions of startup and shutdown. Setting a threshold for all units is inappropriate, particularly a threshold based on percent load. Some units have a minimum stable operating load that is higher than 25 percent (e.g., stable operation for a stoker boiler may not be reached until 60 percent load) . In addition, some control devices cannot be turned on until exhaust gas temperatures reach a certain level, and must be shut off before the temperature dips below this threshold. The ESPs at the City of Painesville, for example, cannot be turned on until the exhaust temperature reaches at least 250 degrees Fahrenheit. At lower exhaust gas temperatures, stack gas can condense on the precipitator plates and cause corrosion. The temperature is dependent on multiple factors, and is not necessarily correlated to a specific load level. AMP agrees that periods of startup and shutdown should be defined for each unit to clearly identify when numeric emission limits apply; however, facilities must be able to define periods of startup and shutdown on a site-specific basis to properly identify the appropriate parameter(s) indicative of stable operating conditions.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 5, regarding maximum time limit for startup/shutdown. See the response to comment EPA-HQ-OAR-2002-0058-3452-A1, excerpt 13, regarding site-specific SS plans.

Commenter Name: Gretchen Brewer

Commenter Affiliation: PT AirWatchers

Document Control Number: EPA-HQ-OAR-2002-0058-3825-A1

Comment Excerpt Number: 4

Comment: SSM - Normal/routine startup and shutdowns need to be limited in number (not used to avoid emissions limits)

Response: The EPA believes that owners/operators have an economic incentive to minimize the number of periods of startup and shutdown. Further, the EPA does not believe it has the authority to stipulate how many such periods are permissible. We believe the revised definitions in the final rule adequately ensure that emissions will be minimized during such periods.

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 46

Comment: As for periods of startup and shutdown, EPA could, at a minimum, require sources to use natural gas (or the cleanest available alternative) as a fuel during periods of startup and shutdown. Further, as the agency recognized, it needs to set limits on the time that sources spend in startup and shutdown mode to prevent the startup and shutdown provisions from being abused as a means to avoid compliance with emission standards. For at least these 18 reasons, EPA's

work practice standards do not reflect the maximum degree of reduction that is achievable and are not, therefore, consistent with § 112(d).

Response: Based on the comments received, the proposed work practice standard for periods of startup and shutdown has been revised. The work practice has been revised to require that all continuous monitoring systems be operated, must use one or a combination of the listed clean fuels, and once start firing coal/solid fossil fuel, heavy liquid fuel, or Gas 2 (other) gases must engage all of the applicable control technologies except dry scrubber, fabric filter, SNCR, and SCR during periods of startup and shutdown. The EPA is not requiring the use of natural gas only during periods of startup and shutdown because natural gas pipelines are not available in all regions of the U.S., and natural gas is simply not available as a fuel or a startup fuel for many industrial, commercial, and industrial boilers. The work practice does require the source to record the type and amount of fuels combusted during each startup, as well as the duration of each startup.

The EPA has also revised the definition of “startup” and shutdown” in the final rule. The EPA is not specifying time limits for periods of startup and shutdown because the time needed for startup depends on many factors, boiler design type, fuel type, type of startup (cold, hot), and control technologies employed. Startup operating procedures vary because of the objectives to protect pressure parts from corrosion, overheating and thermal stresses; to prevent furnace explosions; and production of steam at the desired temperature, pressure and purity. These revisions are tailored for industrial boilers and are consistent with the definitions of “startup” and “shutdown” contained in the 40 CFR part 63, subpart A General Provisions. We believe these revised definitions address the comments and are rational based on the fact that industrial boilers function to provide steam or, in the case of cogeneration units, electricity; therefore, industrial boilers should be considered to be operating normally at all times steam of the proper pressure, temperature, and flow rate is being provided to a common header system or energy user(s) for use as either process steam or for the cogeneration of electricity.

Commenter Name: Douglas A. McWilliams

Commenter Affiliation: American Municipal Power

Document Control Number: EPA-HQ-OAR-2002-0058-3685-A2

Comment Excerpt Number: 19

Comment: Requiring Specific Startup Fuel is Not Feasible for Many Units and Would Be Inconsistent with EPA's Prior Determinations

EPA also requested comment on whether sources should be required to use specific fuels during periods of startup and shutdown. Not all facilities are permitted for or have access to sufficient natural gas to be able to use it as their startup fuel, and not all units are capable of burning natural gas or distillate oil. Specifying the use of natural gas or distillate fuel oil would also result in increased capital and operating costs for many facilities; these fuels are in many cases more expensive than a unit's primary operating fuel and require different infrastructure to accommodate. EPA has not analyzed the cost of requiring potentially extensive infrastructure changes, such as running natural gas lines to areas where natural gas is not currently accessible. These costs may be significant, and the infrastructure projects themselves may generate more

emissions than they save. It would be inappropriate at this time to include a specific fuel requirement when these factors have not yet been quantified and analyzed.

AMP strongly supports EPA's conclusion in the preamble to the June 2010 proposed rule that fuel switching is not an appropriate control option. Mandated fuel switching would be contrary to the goal of safeguarding fuel diversity, which is a fundamental objective of U.S. energy policy. Requiring facilities to use natural gas or distillate fuel oil even for startup purposes would cut against EPA's efforts to reduce overall fossil fuel consumption. A diverse fuel mix protects energy users from fuel unavailability, price fluctuations, and changes in regulatory practices. We believe that the MACT program is not an appropriate vehicle to force fuel choices.

Response: As part of the revisions to the work practice for periods of startup and shutdown, the EPA is requiring the use of specific clean fuels during periods of startup and shutdown. We agree that not all facilities have access to natural gas or sufficient amount of natural gas. In the final rule, the work practice contains a list of several clean fuels. Fuel listed are: natural gas, synthetic natural gas, propane, distillate oil, syngas, ultra-low sulfur diesel, fuel oil-soaked rags, kerosene, hydrogen, paper, cardboard, refinery gas, and liquefied petroleum gas. In addition, the work practice has been revised to require the applicable control technologies to be engaged, except for dry scrubbers, fabric filters, SNCR, and SCR, during periods of startup and shutdown when firing coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel, or gas 2 (other) gases.

Commenter Name: David A. Buff, Golder Associates Inc.

Commenter Affiliation: Florida Sugar Industry (FSI)

Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1

Comment Excerpt Number: 53

Comment: EPA also requests comment on whether sources should be required to use specific fuels during periods of startup and shutdown. Not all facilities are permitted for, or have access to, sufficient supplies of natural gas to be able to use it as their startup fuel. Not all units are capable of burning natural gas or distillate oil. Specifying the use of natural gas or distillate fuel oil would result in increased capital and operating costs for many facilities. The MACT program is not an appropriate vehicle to force the wholesale changes among energy sources that fuel switching to natural gas or distillate fuel oil would entail.

Natural gas and distillate fuel oil are more expensive than the primary operating fuel (bagasse) used in the sugar industry, and the use of these fossil fuels at all sugar mills may require the installation of additional infrastructure. Given these drawbacks with fuel switching, the FSI support EPA's conclusion in the preamble to the June 2010 proposed rule that fuel switching is not an appropriate control option. This conclusion is particularly apt with respect to the FSI's boilers, given the FSI's heavy reliance on clean, renewable, biomass for fuel.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3685-A2, excerpt 19, regarding requiring specific fuels during startup/shutdown.
Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 118

Comment: EPA also requests comment on whether sources should be required to use specific fuels during periods of startup and shutdown. Not all facilities are permitted for or have access to sufficient natural gas or other lower-emitting fuels to be able to use it as their startup fuel, and not all units are capable of burning natural gas or distillate oil. Specifying the use of natural gas or distillate fuel oil would also result in increased capital and operating costs for many facilities; these fuels are in many cases more expensive than a unit's primary operating fuel and require different infrastructure to accommodate, if they can even be made available.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3685-A2, excerpt 19, regarding requiring specific fuels during startup/shutdown.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 17

Comment: EPA also requests comment on whether sources should be required to use specific fuels during periods of startup and shutdown. Not all facilities are permitted for or have access to sufficient natural gas to be able to use it as their startup fuel, and not all units are capable of burning natural gas or distillate oil. Specifying the use of natural gas or distillate fuel oil would also result in increased capital and operating costs for many facilities; these fuels are in many cases more expensive than a unit's primary operating fuel and require different infrastructure to accommodate (which may not be available). We strongly support EPA's conclusion in the preamble to the June 2010 proposed rule that fuel switching is not an appropriate control option²⁶. This conclusion is particularly apt with respect to forest products facilities, due to their need to employ a mix of fuels to control costs and their heavy reliance on biomass residuals and byproducts for fuel.

Many forest products facilities are located in rural areas that lack the necessary gas infrastructure. More generally, gas supplies are limited and industrial uses are of lower priority than residential uses during times of supply shortfalls and cold weather. Industrial boilers also compete with utility boilers for gas supplies and increasing electricity demand in the coming years, coupled with increasing reliance on natural gas to meet that demand, will place further strain on limited gas supplies and distribution networks. Mandated fuel switching for startup would be contrary to the goal of safeguarding fuel diversity, which is a fundamental objective of U.S. energy policy. A diverse fuel mix protects energy users from fuel unavailability, price fluctuations, and changes in regulatory practices. We believe that the MACT program is not an appropriate vehicle to force the wholesale changes among energy sources that fuel switching to natural gas for all unit startups would entail.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3685-A2, excerpt 19, regarding requiring specific fuels during startup/shutdown.

Commenter Name: Jennifer Youngblood
Commenter Affiliation: National Tribal Air Association
Document Control Number: EPA-HQ-OAR-2002-0058-3667-A2
Comment Excerpt Number: 8

Comment: Many startups and shutdowns occur under a set of constraints that are outside the control of the BPH operator. For instance, the BPH rate of change needs to meet criteria that protect the boiler or process heater from thermal damage, the BPH rate of change has to match the steam or process heat demand or, in some situations, the rate at which other equipment can fill that demand, and the rate of change has to match the fuel system's ability to rebalance. In some cases, a startup or shutdown may be impacted by weather changes (e.g., a sudden rain storm can significantly impact combustion efficiency during low firing operations, while having little impact on higher firing operations). The presence of associated equipment (e.g., emission controls, energy efficiency controls, combustion air fans, etc.) or the need to accommodate unusual activities (e.g., dry out repaired refractory, adjust new burners, etc.) can also impose constraints on the duration of these activities. While switching fuel may sound attractive, every fuel switch causes CO spikes and temporarily upsets combustion and thus a requirement to use a specific fuel during startup and shutdown would be counterproductive. Furthermore, the time needed for such switches would increase the duration of the startup or shutdown and, in some case, the facilities to store and/or handle a special fuel would cause increased storage vessel and fugitive emissions. For these reasons, a complex work practice that requires the use of particular fuels, limits the duration of a startups or shutdowns, or otherwise imposes constraints on startup and shutdown activities is unworkable.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3685-A2, excerpt 19, regarding requiring specific fuels during startup/shutdown.

Commenter Name: Jennifer Youngblood
Commenter Affiliation: National Tribal Air Association
Document Control Number: EPA-HQ-OAR-2002-0058-3667-A2
Comment Excerpt Number: 20

Comment: Specifying use of a particular fuel during startup and shutdown is impractical, would lengthen startup and shutdown periods, and should not be considered.

On page 80615 of the proposal preamble, EPA asks for comments on whether the startup and shutdown work practice should include a requirement to operate using specific fuels to reduce emissions during such periods. Such a requirement is impractical, since most boilers and process heaters only have access to one fuel. For those where more than one fuel is available, changing fuels to accommodate such a startup/shutdown requirement would cause enough upset in the operation to likely raise emissions by much more than any potential emissions savings from the relatively short, low mass emission rate startup and shutdown period. Furthermore, switching often fuels requires additional storage and controls and thus increases emissions (storage and fugitive emissions, at least).

Response: See the response to comment EPA-HQ-OAR-2002-0058-3685-A2, excerpt 19, regarding requiring specific fuels during startup/shutdown.

Commenter Name: Jennifer Youngblood
Commenter Affiliation: National Tribal Air Association
Document Control Number: EPA-HQ-OAR-2002-0058-3667-A2
Comment Excerpt Number: 21

Comment: EPA makes clear in this rulemaking that emissions are essentially the same for fuels in a particular subcategory (since there is one emission standard per subcategory). Thus, to impact emissions a source would have to switch to fuels from another subcategory. For instance, presumably, some units have the capability to switch from a liquid subcategory to a gas subcategory fuel. In switching fuels from a liquid to a gas or from a solid to a liquid or gas, where such capability exists, emissions increase because the air controls are not set for that operation (and often excess air must be used during the switch to handle transients). During startup and shutdown there is not time to reoptimize combustion conditions for a different fuel because everything is changing. So, in addition to emissions associated with loss of control and low rates for the normal fuel, there will be increased emissions from firing a different fuel and not starting from optimized operation of that fuel. In addition, changing between subcategories requires notice to permitting Agencies and will require separate reporting under this proposal in the periodic report. Overall, there is unlikely to be any benefit from requiring a unit to change fuels during startup and shutdown, but there will most likely be an increase in emissions and in unnecessary and wasteful regulatory burdens imposed.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3685-A2, excerpt 19, regarding requiring specific fuels during startup/shutdown.

Commenter Name: Robin Mills Ridgway
Commenter Affiliation: Purdue University
Document Control Number: EPA-HQ-OAR-2002-0058-3668-A2
Comment Excerpt Number: 5

Comment: EPA also requests comment on whether sources should be required to use specific fuels during periods of startup and shutdown (76 FR 80615). Not all facilities are permitted for or have access to sufficient natural gas or other lower-emitting fuels to be able to use it as their startup fuel, and not all units are capable of burning natural gas or distillate oil. Specifying the use of natural gas or distillate fuel oil would also result in increased capital and operating costs for many facilities; these fuels are in many cases more expensive than a unit's primary operating fuel and require different infrastructure to accommodate, if they can even be made available.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3685-A2, excerpt 19, regarding requiring specific fuels during startup/shutdown.
Commenter Name: Steve Gossett
Commenter Affiliation: Eastman Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3669-A2
Comment Excerpt Number: 32

Comment: EPA also solicits comments on the idea to require use of specific fuels to minimize emissions during such periods. Eastman objects to any mandated use of such fuels as natural gas during startup. Some boilers such as stoker boilers have no natural gas burners to even consider such use. Emissions are minimized by ensuring control devices are energized (excepting the case

of a spray dryer absorber, when sorbent spray cannot be started until the flue gas reaches a certain minimum temperature). Other units may initiate startup on natural gas but begin the introduction of coal in order to complete the startup because the gas burners are not sized to provide sufficient thermal energy to allow full startup of all downstream equipment.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3685-A2, excerpt 19, regarding requiring specific fuels during startup/shutdown.

Commenter Name: Janice E. Nolen

Commenter Affiliation: American Lung Association

Document Control Number: EPA-HQ-OAR-2002-0058-3679-A2

Comment Excerpt Number: 12

Comment: Work Practice Standards for Startup and Shutdown. We welcome the decision to address the startup and shutdown periods and ensure that boiler operators are trained in startup and shutdown procedures, particularly in procedures to minimize emissions. However, the proposal relies only on work practice standards during the startup and shutdown phases while not establishing numeric emission limits or other performance metrics for units for those phases. As suggested in the proposed reconsideration, we would support requiring the use of specific fuels during the startup and shutdown phases that would reduce harmful air emissions in the absence of emissions standards (EPA, 2011d).

Response: Thank you for your support for requiring the use of clean fuels during startup. See the response to comment EPA-HQ-OAR-2002-0058-3685-A2, excerpt 19, regarding requiring specific fuels during startup/shutdown.

Commenter Name: Shawn Good

Commenter Affiliation: Pennsylvania Chamber of Business and Industry

Document Control Number: EPA-HQ-OAR-2002-0058-3671-A2

Comment Excerpt Number: 7

Comment: In response to EPA solicitation, we oppose any time limitation on shutdowns and startups. The duration of shutdowns and startups should be determined solely by the time required to complete in a safe and effective manner the scope of the work to be performed. Imposing time limitations will be disruptive to the already complex shutdown and startup procedures, and could even create unsafe conditions. Additionally, EPA requested comments on whether to include the use of specific fuels during shutdown and startup periods. We also oppose this provision as a standard requirement, since it would be impractical to implement in many occasions.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3465-A1, excerpt 5, regarding maximum time limit for startup/shutdown. See the response to comment EPA-HQ-OAR-2002-0058-3685-A2, excerpt 19, regarding requiring specific fuels during startup/shutdown.

Commenter Name: Mark Anthony
Commenter Affiliation: Alyeska Pipeline Service Company
Document Control Number: EPA-HQ-OAR-2002-0058-3684-A2
Comment Excerpt Number: 5

Comment: Alyeska supports EPA's recognition that the startup and shutdown of boilers are different from normal operation. Alyeska agrees with the API/NPRA comments that a work standard is the proper standard. For example, the VMT boilers must be run at their intermediate and upper ranges during part of startup to ensure proper tuning over the full operating range before being returned to normal service. For this reason startup will include periods when the boilers are operated at that or above 25%. Only a reasonable work practice approach ensures that boilers are started up safely and efficiently to ensure effective routine operations after startup.

Finally, there is no alternative fuel for these boilers. They can only operate on gaseous fuel as described above and on liquid distillate fuel, also described above. Prescribing a startup alternative fuel is not remotely feasible.

Response: See the responses to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46, regarding 25% load SS definition threshold, and comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5, regarding use of manufacturer's specifications. See the response to comment EPA-HQ-OAR-2002-0058-3685-A2, excerpt 19, regarding requiring specific fuels during startup/shutdown.

Commenter Name: Richard Krock
Commenter Affiliation: The Vinyl Institute
Document Control Number: EPA-HQ-OAR-2002-0058-3526-A1
Comment Excerpt Number: 14

Comment: Definitions for Startup and Shutdown Periods Should be Revised to Allow for the Full Range of Startup and Shutdown Events

The VI does not support EPA's proposed definitions for "startup" and "shutdown." As proposed, periods of startup and shutdown include only cold start and complete shutdown (i.e., no fuel in the unit). The VI submits that the proposed definitions are based on boiler operating terms and by their plain language appear to exclude process heaters. Further, these definitions do not account for actual boiler and process heater operating conditions, which may involve periods of cycling up and down without a complete shutdown.

EPA proposes to define startup as "the period between the state of no combustion in the unit to the period where the unit first achieves 25 percent load (i.e., a cold start)." Similarly, EPA proposes to define shutdown as "the period that begins when a unit last operates at 25 percent load and ending with a state of no fuel combustion in the unit." EPA's decision to key these definitions to specific load parameters appears to exclude process heaters, which do not achieve a "percent load" in defining a startup or shutdown sequence. A process heater's startup sequence is based on increased fuel firing rate, not load percent, because process heaters are designed to transfer heat indirectly to a process material in order to create a chemical reaction (e.g., cracking ethylene dichloride into vinyl chloride monomer).

Response: See the responses to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46, regarding 25% load SS definition threshold, and comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5, regarding use of manufacturer’s specifications.

Commenter Name: Richard Krock

Commenter Affiliation: The Vinyl Institute

Document Control Number: EPA-HQ-OAR-2002-0058-3526-A1

Comment Excerpt Number: 15

Comment: The definitions do not accurately capture the range of operations that constitute startup and shutdown for process heaters. EPA states in the preamble that the “definitions are intended to ensure that units cannot cycle in and out of startup or shutdown,” presumably to prevent an affected source from actively managing the load to limit compliance requirements. There are logical reasons for preventing units from cycling in and out of startup or shutdown, such as the decreased efficiency and increased emissions common to such periods; the need for minimizing reintroduction of combustibles into the burners and thereby reducing number of ignitions for safety reasons; protection of refractory material from cracking and spalling during complete cooldowns; and protection of tubes and tube supports from the bending, cracking and breaking consequences associated with rapid thermal expansion or contraction from improper cooling down or heating up. Because of the sometimes intermittent need for a process heater, however, a process heater may be re-started after an activity, which does not bring it down to a “cold start,” but rather to a “warm start.” A “warm start” also may occur after a maintenance activity or a partial shutdown for replacement of equipment. Similarly, there may be shutdown events that do not meet EPA’s proposed definition. For example, a process heater may be on warm shutdown for purposes of maintenance, replacement of a tube, emission monitoring maintenance, or temporary shutdown due to a process-related issue. The CAA requires that the standards established under section 112(d) be “achievable” and is not intended to prohibit necessary maintenance activities. These activities are typically short in duration, infrequent, and meet EPA’s stated reasons in the final Boiler MACT for applying work practice standards to startup and shutdown:

EPA determined that it is not feasible to require stack testing—in particular, to complete the multiple required test runs—during periods of startup and shutdown due to physical limitations and the short duration of startup and shutdown periods. Operating in startup and shutdown mode for sufficient time to conduct the required test runs could result in higher emissions than would otherwise occur. Based on these specific facts for the boilers and process heater source category, EPA has developed a separate standard for these periods, and we are finalizing work practice standards to meet this requirement.

Consequently and because the proposed definitions of startup and shutdown do not address all startup and shutdown events, nor are they written for both process heaters and boilers, the VI recommends that EPA revise the definitions of startup and shutdown and remove the requirements for cold starts and complete shutdown, at least for units that do not normally operate at high load conditions. Good combustion practices can be followed at all times to minimize emissions.

Response: See the responses to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46, regarding 25% load SS definition threshold, and comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5, regarding use of manufacturer's specifications.

Commenter Name: Jennifer Youngblood

Commenter Affiliation: National Tribal Air Association

Document Control Number: EPA-HQ-OAR-2002-0058-3667-A2

Comment Excerpt Number: 15

Comment: The proposed work practice in Table 3 Item 5 requires "... you must ensure that boiler operators are trained in startup and shutdown procedures, including maintenance and cleaning, safety, control device startup, and procedures to minimize emissions; ..." We see two issues with this wording. First, it only mentions boiler operators, but the requirements apply to process heaters as well. We suggest the word "boiler" be deleted. Second, maintenance and cleaning are not generally operator responsibilities and certainly are not done during startup and shutdown periods as defined in the rule, and thus there is no need for operators to be trained on these techniques. Where such maintenance is needed mechanics are generally called in. These mechanics may be employees, regular maintenance contractors, or outside boiler or process heater specialists, depending on the need. Furthermore, maintaining a boiler or process heater is a very general term covering everything from sheet metal work to refractory to instrumentation to extremely specialized burner and tube technology, little of which has anything to do with combustion efficiency and none of which has anything to do with startup and shutdown. Thus, we see no need for such a broad and unclear requirement in a startup and shutdown work practice and no way of demonstrating compliance. The requirement to train operators on maintenance and cleaning should be deleted since these activities have nothing to do with assuring good combustion during startup and shutdown and are not the operator's responsibility in any case.

Response: See the responses to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 46, regarding 25% load SS definition threshold, and comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 5, regarding use of manufacturer's specifications.

12C. Startup/Shutdown: Applicability to Operating Parameters and Opacity

Commenter Name: David A. Buff, Golder Associates Inc.

Commenter Affiliation: Florida Sugar Industry (FSI)

Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1

Comment Excerpt Number: 50

Comment: FSI supports EPA's decision to establish work practice standards for periods of startup and shutdown, rather than enforcing emission limits. The FSI is not aware of any emissions data for bagasse fired boilers that were obtained during startup and shutdown conditions, other than the CO data for U.S. Sugar Boiler No. 8, which has a CO CEMS. The FSI also supports EPA's determination that operating parameter limits and opacity limits should not apply during periods of startup and shutdown, because work practices standards will apply during these times.

Response: The EPA thanks the commenter for their support.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 112

Comment: ACC also agrees with the clarification EPA has made to Table 2 to indicate that emission limits do not apply during periods of startup and shutdown, as work practices and not numeric emission standards apply during these times as provided in § 63.7540(d).

Response: The EPA thanks the commenter for their support.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 12

Comment: We support the inclusion of work practice standards in the rule for periods of startup and shutdown. EPA has proposed to expand upon the work practice requirements in the March 2011 rule by adding specific requirements to employ good combustion practices, train operators on proper startup and shutdown procedures, and maintain records (see Table 3 of the proposed rule). We agree that these are appropriate requirements. We also agree with the clarification EPA has made to Table 2 to indicate that operating parameter limits and opacity limits do not apply during periods of startup and shutdown, as work practices and not numeric emission standards apply during these times.

Response: The EPA thanks the commenter for their support.

Commenter Name: Douglas A. McWilliams

Commenter Affiliation: American Municipal Power

Document Control Number: EPA-HQ-OAR-2002-0058-3685-A2

Comment Excerpt Number: 20

Comment: Operating Parameters and Opacity limits Should Not Apply During Periods of Startup and Shutdown

AMP supports the clarification EPA made to Table 2 of the Proposed Rule, which indicates that operating parameter limit and opacity limits do not apply during periods of startup and shutdown because numeric emission limits do not apply during these time periods. These parameters are designed to ensure continuous compliance with the numeric emission limits, and bear no correlation to whether good combustion practices are being employed during periods of startup and shutdown.

Response: The EPA thanks the commenter for their support.**Commenter Name:** Elizabeth McMeekin

Commenter Affiliation: PPG Industries, Inc

Document Control Number: EPA-HQ-OAR-2002-0058-3778-A1

Comment Excerpt Number: 15

Comment: We agree with the clarification EPA has made to Table 2 to indicate that emission limits do not apply during periods of startup and shutdown, as work practices and not numeric emission standards apply during these times as provided in 63.7540(d).

Response: The EPA thanks the commenter for their support.

Commenter Name: J. Michael Geers

Commenter Affiliation: Duke Energy

Document Control Number: EPA-HQ-OAR-2002-0058-3543-A1

Comment Excerpt Number: 8

Comment: EPA then describes monitoring O2 levels as part of the work practice standards for startup and shutdown. 76 Fed. Reg. 80,602

In the final standards, Duke Energy strongly cautions EPA about requirements it might impose upon operations regarding O2 levels during start-up periods for safety reasons. During start-up, operators are required to maintain sufficient levels of excess air in their boilers to guard against the danger of explosion and other potential forms of damage. The procedures for operating a specific boiler are first specified by the boiler manufacturer, and then if needed, adapted to reflect site specific circumstances. Failure to use procedures such as these has resulted in fires, explosions, equipment damage, injury and at times loss of life. In no way should EPA attempt to impose limits or controls that would run counter to the safe operating procedures established by manufacturers and operators. Because of the wide variety of boiler sizes, types and classes, EPA should instead require operators to follow established procedures for that particular unit that follow good combustion practices.

Response: The EPA has made clarifications to Table 2 to indicate that operating parameter limits and opacity limits do not apply during periods of startup and shutdown, as work practices and not numeric emission standards apply during these times.

Commenter Name: Jennifer Youngblood

Commenter Affiliation: National Tribal Air Association

Document Control Number: EPA-HQ-OAR-2002-0058-3667-A2

Comment Excerpt Number: 11

Comment: The proposed work practice for BPH during start-up and shutdown are appropriate in concept for units subject to emission limits, but the specifics need revision to make the requirements clearer, less costly, and more workable.

The work practice requirements that apply during startup and shutdown for boilers and process heaters subject to Table 1 or 2 numerical emission limits during normal and malfunction operation are located in Item 5 of Table 3. However, Item 5 of Table 3 is not labeled as being limited to startup and shutdown periods and that labeling should be corrected to only apply the startup and shutdown work practice during periods of startup and shutdown. This work practice

is not needed when the Table 1 and 2 numerical emission limits are being met, since those standards, particularly the CO standard assure good combustion. Furthermore, by referencing "startup and shutdown periods" it would be clear that the O2 monitoring requirement does not apply during periods of no fuel combustion, which is currently unclear.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3543-A1, excerpt 8.

Commenter Name: Jennifer Youngblood

Commenter Affiliation: National Tribal Air Association

Document Control Number: EPA-HQ-OAR-2002-0058-3667-A2

Comment Excerpt Number: 16

Comment: Item 5 in Table 3 could be read to require continuous monitoring of oxygen during periods of startup and shutdown and even automatic control. As we discuss in Comment II.9.A.2, not all BPH have oxygen analyzers and the rule should be clear that continuous monitoring is not required in such cases. Furthermore, where units have automatic control, it is often necessary for safety reasons to go to manual control during portions of the startup and shutdown operation. As burners are lit or extinguished, oxygen demands can swing wildly and large amounts of excess air are needed to avoid firebox vacuum situations or burner extinguishment and explosive reignition. During these times draft is usually set at a fixed position and large amounts of excess air supplied until operations stabilize. The rule should be clear that automatic draft, oxygen or CO control is not required during startup and shutdown periods.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3543-A1, excerpt 8.

Commenter Name: M.L. Steele

Commenter Affiliation: CraftMaster Manufacturing, Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3814-A1

Comment Excerpt Number: 14

Comment: The CO CEM's limits in Table 2 are not applicable during periods of start-up and shutdown per §63.7575(a), however oxygen must be monitored during these periods. Because CO is being monitored in place of oxygen, the implication is that CO must be monitored at all times including start-up and shutdown. Then CO CEMS data is reported during start-up and shutdown but that data is not considered in the demonstration of compliance with the limits in Table 2. Please confirm that this is USEPA's intent.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3543-A1, excerpt 8.

Commenter Name: Mark Anthony

Commenter Affiliation: Alyeska Pipeline Service Company

Document Control Number: EPA-HQ-OAR-2002-0058-3684-A2

Comment Excerpt Number: 7

Comment: We are concerned that there are interpretations of 63.7535 through 63.7541 that could require that Compliance Requirements be met during periods of startup or shutdown. Specifically: section § 63.7500(e) states that the standards, except the work practice standards in

Table 3, do not apply during periods of startup and shutdown, however under the Continuous Compliance Requirements sections, § 63.7535 through § 63.7541 there is no mention that data taken during episodes of startup or shutdown should not be considered or used in evaluating ongoing emission or monitoring requirements. Several of the provisions, such as § 63.7535(c) acknowledge that monitoring data taken during monitoring system malfunctions, out-of-control periods, or during repairs on the monitoring systems should not be used, but it is silent for periods when the boiler is in startup or shutdown. Another example includes Section § 63.7540(a)(8) for CO CEMS which states under § 63.7540(8)(ii) to "maintain a CO emission limit below or at your applicable alternative CO CEMS based standard in Tables 1 and Table 2 of this subpart at all times" (emphasis added). Perhaps the means to address this concern would be to add to 63.7535(d) and 63.7540(a)(ii): "except during periods of startup and shutdown as described by § 63.7500(e)".

Response: The EPA disagrees with the commenter. Unlike periods of malfunctions or system QA/QC, the EPA intends for data to be collected during startup and shutdown. In the revised work practice for startup and shutdown Table 3 specifies that CMS are to be operated during periods of startup and shutdown. The definition of 30-day rolling average includes a phrase to indicate what data is valid for use in the computation of continuous monitoring and/or emissions requirement and this definition excludes startup and shutdown.

Commenter Name: Robin Mills Ridgway

Commenter Affiliation: Purdue University

Document Control Number: EPA-HQ-OAR-2002-0058-3668-A2

Comment Excerpt Number: 6

Comment: Purdue asks that startup and shutdown periods not be included in emissions averaging by adding the words: "...except periods of start up and shut down" to §63.7522(d).

Response: The EPA agrees with this change. See the response to comment EPA-HQ-OAR-2002-0058-3684-A1, excerpt 7.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 119

Comment: Startup and shutdown should be appropriately reflected in proposed §63.7540 and associated compliance provisions.

As provided in §63.7500(e), numerical emission limits do not apply during periods of startup and shutdown and, thus, monitoring results obtained during periods of startup and shutdown must be excluded from numerical emission limit compliance calculations.

1. Proposed §63.7540(a)(1) applies Table 4 operating limits during periods of startup and shutdown and makes exceedances of those limits deviations, although proposed §63.7500(e) makes clear that only the work practice standard in Table 3 Item 5 applies during such times for

units subject to Table 1 or 2 emission limits. A startup and shutdown exception must be added to §63.7540(a)(1).

Response: See the response to comment EPA-HQ-OAR-2002-0058-3684-A1, excerpt 7.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 120

Comment: Proposed §63.7540(a)(8)(ii) applies the Table 1 or 2 emission limit for CO determined with a CO CEMS at all times, although proposed §63.7500(e) makes clear that only the work practice standard in Table 3 Item 5 applies during such times for units subject to Table 1 or 2 emission limits. A startup and shutdown exception must be added to §63.7540(a)(8)(ii).

Response: See the response to comment EPA-HQ-OAR-2002-0058-3684-A1, excerpt 7.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 121

Comment: Proposed §63.7540(b) requires that you report each instance in which you did not meet each emission limit and operating limit in Tables 1 through 4 to this subpart that apply to you. Further, it specifies that those instances are deviations. Since the Tables 1, 2 and 4 requirements do not apply during periods of startup and shutdown, you should not have to report instances where you did not meet the requirements in those tables during startup and shutdown and those instances certainly are not deviations. A startup and shutdown exception must be added to §63.7540(b) relative to Tables 1, 2 and 4.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3684-A1, excerpt 7.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 122

Comment: The proposed definition of "daily block average" requires that monitoring results from periods of startup and shutdown be included in the average. A startup and shutdown period exception must be added to the definition of "daily block average."

Response: See the response to comment EPA-HQ-OAR-2002-0058-3684-A1, excerpt 7.

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 42

Comment: In its final rule, the Agency also provided a separate work-practice standard for start-ups and shut-downs, arguing that the "short duration of startup and shutdown periods," along with unspecified "physical limitations," make the procedures imposed during general operations impracticable. 76 Fed. Reg. at 15,642. The Act does not allow the Agency to avoid numeric standards merely because one set of procedures – here, those established by the Rule to govern normal operations – are impracticable. Work practice standards are permitted only where it is entirely "infeasible to prescribe or enforce an emission standard." 42 U.S.C. § 7412(h)(1). Moreover, the Agency did not exclude start-ups and shut-downs from the data used to determine the MACT floor. By doing so, it inflated its limits substantially (especially in light of its variability adjustment). That inflation is wholly unjustified, if the limits do not apply during start-up and shut-down; startup and shutdown emissions do not reflect the sources' actual emissions during other operations.

Response: Consistent with *Sierra Club v. EPA*, EPA has established standards in this final rule that apply at all times. In establishing the standards in this final rule, EPA has taken into account startup and shutdown periods and has established different standards for those periods. EPA has revised this final rule to require sources to meet a work practice standard, which requires following the manufacturer's recommended procedures for minimizing periods of startup and shutdown, for all subcategories of new and existing boilers and process heaters (that would otherwise be subject to numeric emission limits) during periods of startup and shutdown. EPA believes that the expected startup and shutdown emissions over the averaging periods established for the NESHAP are not likely to cause a violation of the standards. EPA also found no evidence that suggested that emissions were higher during startup or shutdown that would indicate a need for an alternate standard for these periods and the commenter provided no data or basis to show that sources cannot comply with the standards as proposed. Thus we set standards based on available information as contemplated by section 112.

Commenter Name: Randall D. Quintrell

Commenter Affiliation: Georgia Paper & Forest Products Association

Document Control Number: EPA-HQ-OAR-2002-0058-3451-A1

Comment Excerpt Number: 11

Comment: Since startups and shutdowns have work place standards and such data were not included in the continuous standard, these periods should be excluded from the continuous data average for compliance.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3511-A1, excerpt 42.

Commenter Name: Sarah Hedrick

Commenter Affiliation: Verso Paper Corp.

Document Control Number: EPA-HQ-OAR-2002-0058-3537-A2

Comment Excerpt Number: 8

Comment: Oxygen is not measured in the firebox. Oxygen is measured at the outlet of the boiler. The rule needs to be revised to more broadly describe where oxygen may be measured.

Response: The EPA agrees with the commenter and has revised the definition of oxygen analyzer system in final rule to explain the location of the measurement more broadly. Further, the requirement to measure oxygen on an hourly basis throughout startup and shutdown has been removed from the final rule.

Commenter Name: Jennifer Youngblood

Commenter Affiliation: National Tribal Air Association

Document Control Number: EPA-HQ-OAR-2002-0058-3667-A2

Comment Excerpt Number: 9

Comment: The terms of "state of no combustion" and "state of no fuel combustion" should be consolidated and explained. We recommend consolidating on "state of no fuel combustion." By either defining this term or adding a sentence to the startup and shutdown definitions, it should be clarified that pilot lights may remain lit during the state of no fuel combustion. When a BPH is shutdown for the purpose of entry, pilot lights will be extinguished, but when the BPH is shutdown but not being entered safety concerns will often require that the pilots remain lit. Even if there is no safety concern, it is often common practice to light pilots well ahead of actually firing up any burners, so as to be prepared, and it is common practice to keep the pilots lit after all the burners are shutdown, until the BPH fuel gas is blinded away. Pilots are very small flames, usually fueled with natural gas and thus result in immeasurably small emissions and having them operating on their own certainly does not justify the burdens associated with the startup and shutdown work practice (O₂ monitoring).

Response: The EPA has revised the definitions of startup and shutdown in the final rule and the terms "state of no combustion" and "state of no fuel combustion" are no longer used in the final rule language.

Commenter Name: Jennifer Youngblood

Commenter Affiliation: National Tribal Air Association

Document Control Number: EPA-HQ-OAR-2002-0058-3667-A2

Comment Excerpt Number: 14

Comment: In those cases where a CO CEMS is being used to demonstrate compliance with the Table 1 or 2 CO limits, operators should be allowed to use CO instead of oxygen for demonstrating good combustion practice during startup and shutdown periods. Thus, we also recommend that the first sentence of the Table 3 Item 5 requirement be changed to allow monitoring of either oxygen or CO.

Response: We have revised item 5 of Table 3 to be consistent with the recent MATS rule at 40 CFR part 63 subpart UUUUU. This adjustment requires the source to operate all CMS during

startup and shutdown, which would include operation of CO CEMS for units demonstrating compliance with the CO emission limits with a CEMS.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 85

Comment: Proposed §63.7501(a)(3):

The frequency, amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions; and

Proposed §63.7501(a)(4):

If the excess emissions resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and

Proposed §63.7501(a)(4) correctly identifies safe operation as a necessity and is an improvement over earlier language that suggested the Agency was not concerned about personnel safety unless the injuries avoided were "severe". We appreciate the recognition that all injuries are a concern and should be avoided.

However, similarly, EPA should not be suggesting that they are only concerned with "severe" property damage. Nor is it clear how the Agency expects an operator, during an emergency, to decide whether the property damage that might occur due to a failure to act would be "severe." The word "severe" should be deleted from this proposed language. Any situation that presents a risk to property or equipment could be more or less "severe" in the end, but the level of potential damage cannot be precisely foreseen. In addition, there can be substantial room for disagreement about what constitutes "severe" property damage. The use of "severe" renders this requirement too subjective to be practically enforceable.

Moreover, potential "severity" is not the proper focus. Bypassing control equipment or the process in some cases might be an appropriate exercise of good air pollution control practices. For example, a bypass can be the appropriate response to an upset (e.g., in order to prevent fouling of the pollution control equipment media). Such a bypass could save the control device from damage and thus result in reduced control equipment downtime or increased pollutant removal.

Response: The EPA believes that a bypass of control equipment or a process, which results in a violation, should be an exception and not undertaken lightly, and has maintained the word "severe" in this criteria.

12D. Affirmative Defense for Malfunctions

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 106

Comment: Turning to the 2-day notification requirement in § 63.7501(b), ACC notes that EPA recently proposed almost identical affirmative defense requirements in the CMAS proposed reconsideration but omitted the 2-day notification. It is ACC's understanding that the Agency has been persuaded by comments submitted by ACC and others that the 2-day notification requirement is onerous and burdensome. ACC also understands that EPA may be revisiting some of the other requirements in the affirmative defense provisions in order to further reduce the burden on facilities, and therefore request that in its reconsideration EPA abandon the 2-day notification requirement in the final provisions for major source boilers and process heaters.

Unlike the 2-day notification which is triggered by the "initial occurrence of the malfunction," the 45-day period for submitting a written report demonstrating that the party qualifies for the affirmative defense commences on the date of "the initial occurrence of the exceedance of the standards." Complying with this timeframe presents several challenges, specifically because most of the content of the report may not be able to be created until the malfunction has ended, which in some cases could be a number of days.

While there is an opportunity for requesting and obtaining an extension of the reporting deadline of up to 30 additional days, the owner/operator must comply with the original 45-day requirement unless and until he hears back from EPA that the extension request is approved. However, there is no requirement for EPA to act timely in granting or denying an extension request. At a minimum, the rule should provide a timeframe within which EPA must act on a request and if it fails to do so, the request would be considered granted.

Response: The EPA has evaluated some of the affirmative defense criteria, and is revising both the immediate notification and 45-day malfunction report. Instead, the final rule allows owners or operators seeking to assert an affirmative defense to demonstrate, with all necessary supporting documentation (as was required under the proposed 45-day report), that it has met the affirmative defense criteria by submittal of the affirmative defense report in the first periodic compliance, deviation report or excess emission report otherwise required after the initial occurrence of the violation of the relevant standard (which may be the end of any applicable averaging period). If such compliance, deviation report or excess emission report is due less than 45 days after the initial occurrence of the violation, the affirmative defense report may be included in the second compliance, deviation report or excess emission report due after the initial occurrence of the violation of the relevant standard. This change provides sources with sufficient time to demonstrate that they have met the required affirmative defense criteria.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 90

Comment: The two-day notice requirement in proposed §63.7501(b) associated with claiming the affirmative defense is unreasonable and will introduce wasteful and unnecessary burdens and

should not be finalized. It serves no purpose and certainly violates the Paperwork Reduction Act and Executive Order 13563 intents.

In order to use the affirmative defense, a source is required by proposed §63.7501(b) to file a notice of that intent within two business days of the start of the event. For many events the information required to decide if there was an exceedance and if the source will claim the affirmative defense will not be available within two business days from the start of the event. In order not to forfeit their rights in light of this unreasonable deadline, sources must file an affirmative defense notice for every event whether or not there was an actual exceedance.

Many compliance requirements have long averaging times (30 day averages are commonly specified in this rule). Where the averaging times exceed two days, a source often will not even know there was an exceedance in the two days after the start of the event. Even with a one day averaging time, sources would have to decide in less than one day if they plan to use the affirmative defense and make the notice that day. If this notice requirement is maintained the time period for the notice (and for meeting the other affirmative defense requirements) should start with the date that the site determined in accordance with rule requirements that there was an exceedance, rather than from the start of the event.

Under the Refinery Consent Decrees, such notices have typically not been required and lack of these notices does not appear to have had any impact on the use of the affirmative defense or caused any increase in emissions or lessened the response to the event. In fact, if anything, diverting resources from dealing with an event and making reports to authorities associated with immediate response to the event is more likely to have detrimental environmental impacts rather than positive impacts. These notices certainly serve no purpose for immediate response, since notices for those purposes are already required to be provided on a much shorter timeframe to the National Response Center and State and Local Authorities.

Additionally, it is unclear how to handle this notice requirement for multiple exceedances associated with a single event. For instance, a single event could cause a 30 day rolling average to be exceeded for each of 30 days. Are 30 2-day notices required? If this requirement is maintained, the Agency should clarify that only one notice (and one follow-up demonstration letter) is required even if an individual event causes multiple excess emission exceedances.

For these reasons, we recommend EPA delete the 2-day initial notification requirement as unnecessary, leaving in place only the written demonstration requirement. We believe there is no reason the notification of the decision to use the affirmative defense should be on a different schedule as the supporting information submittal. In fact, EPA never explains what action they will take as a result of this notice or why they need it, since they will not have any information on which they will evaluate the event and its response until the later submission.

Response: The EPA has removed the requirement to notify the EPA within two days of violation of a standard in order to be able to avail themselves to a claim for affirmative defense and instead requires that the affirmative defense report be included in the first periodic compliance, deviation report or excess emission report otherwise required after the initial occurrence of the violation of the relevant standard (which may be the end of any applicable averaging period). If such compliance, deviation report or excess emission report is due less than 45 days after the initial occurrence of the violation, the affirmative defense report may be

included in the second compliance, deviation report or excess emission report due after the initial occurrence of the violation of the relevant standard .

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 60

Comment: Assuming *arguendo* that EPA had authority to promulgate any type of affirmative defense to penalties for malfunctions, EPA should also promulgate the following provision: EPA should promulgate specific public reporting and notification requirements for malfunctions, or any emission exceedance that occurs of which an operator is aware. Specifically, EPA should require that when a facility provides EPA with a notification of a malfunction or emission standard exceedance under the regulations, this notice will be made publicly available on EPA's website within 14 days. In addition, EPA should promulgate the requirement that when such notification is made, the facility must also provide for community notification of the malfunction or emission standard exceedance within 2 business days, through an appropriate public forum that is designed to reach residents who live near the facility, including but not limited to a notice on the facility's own website (if it has one), a written notice to the local municipality and local school district, a press release to the local newspaper, radio, and TV news station that contains information community members may need to protect themselves and their families from the additional air pollution.

Response: The EPA has evaluated some of the affirmative defense criteria, and is revising both the immediate notification and 45-day malfunction report. The EPA has removed the requirement to notify the EPA within two days of violation of a standard in order to be able to avail themselves to a claim for affirmative defense. Instead, the final rule allows owners or operators seeking to assert an affirmative defense to demonstrate, with all necessary supporting documentation (as was required under the proposed 45-day report), that it has met the affirmative defense criteria by submittal of the affirmative defense report in the first periodic compliance, deviation report or excess emission report otherwise required after the initial occurrence of the violation of the relevant standard (which may be the end of any applicable averaging period). If such compliance, deviation report or excess emission report is due less than 45 days after the initial occurrence of the violation, the affirmative defense report may be included in the second compliance, deviation report or excess emission report due after the initial occurrence of the violation of the relevant standard. This change provides sources with sufficient time to demonstrate that they have met the required affirmative defense criteria.

Commenter Name: Russell A. Wozniak

Commenter Affiliation: The Dow Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3449-A1

Comment Excerpt Number: 22

Comment: The immediate notification (within 2 working days) requirement as a pre-requisite for asserting the affirmative defense should be eliminated for at least the following reasons and replaced with a semi-annual reporting requirement:

It is burdensome and duplicative of emergency response reporting requirements under SARA/CERCLA/EPCRA and many state regulations for larger excess emission events.

This new requirement will contradict many existing reporting rules by requiring the reporting of emission quantities well below CERCLA/SARA/State Agency Reportable Quantities. Thus, agencies will be flooded with reports of very small excess emissions.

The rule structure encourages reporting to the agency even if the owner/operator is not sure if an exceedance of an emission limit has occurred for fear of not being able to claim the affirmative defense. Thus, agency reporting systems will become "clogged" with insignificant reports further complicating the ability of all resources to respond to a larger event.

The rule is not clear to whom the reports should be submitted (e.g., the EPA Regional Office, State or Local Agency, LEPC).

Response: See the responses to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 106 and EPA-HQ-OAR-2002-0058-3677-A2, excerpt 90 regarding two-day malfunction notice and 45-day affirmative defense requirements.

Commenter Name: Russell A. Wozniak

Commenter Affiliation: The Dow Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3449-A1

Comment Excerpt Number: 26

Comment: ~~(b)The owner or operator of the facility experiencing an exceedance of its mission limit(s) during a malfunction must notify the Administrator by telephone or facsimile(FAX) transmission as soon as possible, but no later than 2 working days after the initial occurrence of the malfunction, if it wishes to avail itself of an affirmative defense to civil penalties for that malfunction. The owner or operator seeking to assert an affirmative defense must also submit a written report to the Administrator as part of the semi-annual periodic report in within 45 days of the initial occurrence of the exceedance of the standard in 63.7550 to demonstrate, with all necessary supporting documentation, that is has met the requirements set forth in paragraph (k) of this section. The owner or operator may seek an extension of this deadline for up to 30 additional days by submitting a written request to the Administrator before the expiration of the semi-annualreporting45 dayperiod. Until a request for an extension has been approved by the Administrator, the owner or operator is subject to the requirement to submit such report within the required time frame. 45 days of the initial occurrence of the exceedance.~~

Dow Comment: Title V Operating Permit reporting requirements include reporting of events in which emission limits have been exceeded as part of the semi-annual deviation report. Therefore, the Title V Operating Permit reporting program or other semi-annual reporting requirements can be used to supply information on the affirmative defense criteria.

Response: See the responses to comments EPA-HQ-OAR-2002-0058-3510-A1, excerpt 106 and EPA-HQ-OAR-2002-0058-3677-A2, excerpt 90 regarding two-day malfunction notice and 45-day affirmative defense requirements.

Commenter Name: Bruce W. Ramme
Commenter Affiliation: Wisconsin Electric Power Company (WE Energies)
Document Control Number: EPA-HQ-OAR-2002-0058-3452-A1
Comment Excerpt Number: 9

Comment: The majority of malfunctions that result in excess emissions are likely to be minor in nature and result in only minimal excess emissions. In these cases, the stringent reporting requirements in the proposed rule, which include a notification by telephone or facsimile no later than 2 days after the event and submittal of a follow-up report within 45 days of the event, appear burdensome, particularly in light of the compliance reporting requirements of the rule.

Response: See the responses to comments EPA-HQ-OAR-2002-0058-3510-A1, excerpt 106 and EPA-HQ-OAR-2002-0058-3677-A2, excerpt 90 regarding two-day malfunction notice and 45-day affirmative defense requirements.

Commenter Name: Lee Zeugin and Lauren Freeman
Commenter Affiliation: Utility Air Regulatory Group (UARG)
Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1
Comment Excerpt Number: 22

Comment: In order to take advantage of the affirmative defense for a malfunction, an IB operator that does “experience[] an exceedance . . . during a malfunction,” must provide notice to EPA within two days of the “initial occurrence” of the malfunction, and must keep logs of actions taken “in response to the excess emissions.” Requiring IB operators to keep logs of malfunctions is not unreasonable. However, requiring notice to EPA of events before the IB operator even knows whether *an exceedance* will occur, requiring logs in response to exceedances (rather than malfunctions), or requiring that the exceedance occur at the same time as the malfunction, are not reasonable. EPA must rework the rule to recognize that some malfunctions that ultimately result in exceedance of an emission limit may occur long before the exceedance is recorded. EPA should simply require the maintenance of the appropriate records surrounding any event identified by the IB operator as a malfunction and leave the reporting until after all of the data relevant to the compliance determination for the affected period are collected.

Response: See the responses to comments EPA-HQ-OAR-2002-0058-3510-A1, excerpt 106 and EPA-HQ-OAR-2002-0058-3677-A2, excerpt 90 regarding two-day malfunction notice and 45-day affirmative defense requirements. See the response to comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 81 regarding affirmative defense provisions.

Commenter Name: LESLIE SUE RITTS
Commenter Affiliation: National Environmental Development Association's Clean Air Project (NEDA/CAP)
Document Control Number: EPA-HQ-OAR-2002-0058-3529-A1
Comment Excerpt Number: 15

Comment: Because the affirmative defense provisions in the Final ICI MACT were based on EPA’s 1999 enforcement policy, cited above, they lack the sharpness of regulatory language,

rendering the provisions arbitrary and capricious. Also, since an affirmative defense exists under the Agency's 1999 SSM Policy, it is unnecessary to codify. Essentially the ICI MACT provisions are a recordkeeping trap for the unwary or the extremely busy – in other words, those responding to crisis events where safety and recovery activities overwhelm the capacity to meet less critical book keeping requirements. A source should be allowed to prove its entitlement to the affirmative defense using any credible evidence which would otherwise be admissible in court. Sources should not have to maintain an operating log which is not required by the underlying NESHAP just to preserve eligibility for the affirmative defense. Perhaps most importantly, sources experiencing a malfunction should not be forced to direct contemporaneous resources to documenting its actions rather than to actually acting to address safety issues and minimize the excess emissions caused by the malfunction and to correct the malfunction itself.

Response: See the responses to comments EPA-HQ-OAR-2002-0058-3510-A1, excerpt 106 and EPA-HQ-OAR-2002-0058-3677-A2, excerpt 90 regarding two-day malfunction notice and 45-day affirmative defense requirements.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 87

Comment: Proposed §63.7501(a)(6):

All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and

Proposed §63.7501(a)(7):

All of the actions in response to the excess emissions were documented by properly signed, contemporaneous operating logs; and

Proposed §63.7501(a)(7) should be revised to reflect the use of current recordkeeping technology. The use of signed logs has declined with the use of various forms of electronic recordkeeping. Rather operators are directed to focus on optimizing operations, and responding to malfunctions, if necessary, not filling out paperwork. Records are maintained of the event characteristics (often electronically), the amount of excess emissions and the supporting calculations (generally done after the event ends and kept in an engineering file), and the steps taken to deal with the event and the excess emissions (sometimes electronically, sometimes on paper). In fact, most records are electronic and thus it may not even be possible to have them "signed".

Thus, we recommend the following replace the proposed language.

Records are maintained documenting the event, including actions taken to minimize emissions.

Response: As an alternative, the EPA accepts electronically signed operating logs where the format and method of submission meets the regulatory criteria and are compatible with the EPA

and the delegated authorities' electronic submission systems. Any source submitting records electronically should exercise due diligence to assure receipt by the EPA and the delegated authority.

Commenter Name: Felix Mestey, on behalf of Donald R. Schregardus

Commenter Affiliation: Clean Air Act Services Steering Committee, Department of Defense (DoD)

Document Control Number: EPA-HQ-OAR-2002-0058-3427

Comment Excerpt Number: 18

Comment: DoD supports the terms for affirmative defense provisions during malfunctions as written with one exception regarding the notification. To establish the affirmative defense, the owner or operator must timely meet the notification requirements in §63.7501(b). This notification requirement states that *“The owner or operator of the facility...shall notify the Administrator by telephone or facsimile (fax) transmission as soon as possible, but no later than 2 business days after the initial occurrence of the malfunction....”* DoD believes limiting the notification methods by using telephone or facsimile (fax) transmission would prohibit the use of better and more effective emerging electronic technologies. For example, Wright-Patterson AFB currently reports malfunctions to the Ohio EPA using the e-Business Air Services web-based platform and anticipates doing the same for the Boiler MACT because Ohio EPA is considered the “Administrator” for this rule. The Air Services platform is more effective than telephone or fax in that all data transmittals immediately become part of the permanent record stored by the Agency and the regulator assigned to the facility is instantly notified of the submittal. Thus, there would be no more lost faxes or erased phone messages if EPA were to allow the notification by other approved methods such as e-Business Air Services. In addition, many notifications are currently made via e-mail systems. The rule should not limit notification methods to telephone and fax when other methods are acceptable to the permitting authority.

Recommendation DoD recommends changing §63.7501(b) as follows to allow other notification methods to be used if approved by the permitting authority: *“The owner or operator of the facility experiencing an exceedance of its emission limitation(s) during a malfunction shall notify the Administrator by telephone, ~~or~~ facsimile (fax) transmission, or other commonly used electronic methods as soon as possible, but no later than 2 business days after the initial occurrence of the malfunction, if it wishes to avail itself of an affirmative defense to civil penalties for that malfunction. The owner or operator seeking to assert an affirmative defense shall also submit a written report to the Administrator within 45 days of the initial occurrence of the exceedance of the standard in §63.7500 to demonstrate, with all necessary supporting documentation, that it has met the requirements set forth in paragraph (a) of this section. The owner or operator may seek an extension of this deadline for up to 30 additional days by submitting a written request to the Administrator before the expiration of the 45-day period. Until a request for an extension has been approved by the Administrator, the owner or operator is subject to the requirement to submit such report within 45 days of the initial occurrence of the exceedance.*

Response: See the responses to comments EPA-HQ-OAR-2002-0058-3510-A1, excerpt 106 and EPA-HQ-OAR-2002-0058-3677-A2, excerpt 90 regarding two-day malfunction notice and 45-day affirmative defense requirements. See the response to comment EPA-HQ-OAR-2002-

0058-3677-A2, excerpt 81 regarding affirmative defense provisions. See the response to comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 87 regarding use of technology for recordkeeping and reporting.

Commenter Name: Russell A. Wozniak
Commenter Affiliation: The Dow Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3449-A1
Comment Excerpt Number: 24

Comment: 40 CFR §63.7501 (a) (7) All of the actions in response to the excess emissions were documented by properly signed, contemporaneous operating logs; and

Dow Comment: Electronic media to document actions in response to excess emissions is used in our plant that will be subject to this rule. Imposing a requirement to print and sign a record of such action is outdated if one can document the response to actions in an electronic format.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 87 regarding use of technology for recordkeeping and reporting.

Commenter Name: Melvin E. Keener
Commenter Affiliation: Coalition for Responsible Waste Incineration (CRWI)
Document Control Number: EPA-HQ-OAR-2002-0058-3454-A1
Comment Excerpt Number: 11

Comment: In a recently proposed rule (77 Fed. Reg. 4522, 4538, January 30, 2012), EPA proposed dropping the immediate notification process and simply requiring a written report within 45 days of the malfunction. CRWI suggests that the Agency adopt the same change in this regulation. If the Agency keeps the immediate notification requirement, faxing is an obsolete technology. EPA should allow notification by e-mail or other electronic means. As facilities and EPA move toward electronic recordkeeping, it makes no sense to require keeping a "properly signed, contemporaneous operating logs" as a requirement for an affirmative defense. There are a number of electronic methods for maintaining records currently available (and more will likely be available in the future). As such, we suggest modifying this provision. It should also be noted that it is impossible to eliminate the causes for certain malfunctions (e.g., lightning strikes).

Response: See the responses to comments EPA-HQ-OAR-2002-0058-3510-A1, excerpt 106 and EPA-HQ-OAR-2002-0058-3677-A2, excerpt 90 regarding two-day malfunction notice and 45-day affirmative defense requirements. See the response to comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 81 regarding affirmative defense provisions. See the response to comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 87 regarding use of technology for recordkeeping and reporting.

Commenter Name: Kevin G. Desharnais, Attorney, Mayer Brown LLP
Commenter Affiliation: United States Sugar Corporation
Document Control Number: EPA-HQ-OAR-2002-0058-3496-A1
Comment Excerpt Number: 1

Comment: EPA's Reconsideration Proposal retains the requirement that malfunction events be addressed through an affirmative defense. The Reconsideration Proposal does not address the myriad issues arising from its treatment of malfunction events through an affirmative defense and ignores the practical realities of that process. An affirmative defense is not an appropriate substitute for development of an achievable standard applicable during malfunction events reflecting what is actually achieved in practice by the best performing sources when a malfunction occurs.

The affirmative defense regulations inappropriately shift the burden to a source to disprove alleged violations, requiring a detailed analysis of each malfunction event, compiled into a nine-part report due within 45 days of the event. See 40 CFR 63.7501. The drafting of these reports will occupy a significant amount of employee time at significant cost to the regulated community, and the review of the reports will place a significant burden on already understaffed and overtaxed agencies. This is not a workable solution.

Response: See the responses to comments EPA-HQ-OAR-2002-0058-3510-A1, excerpt 106 and EPA-HQ-OAR-2002-0058-3677-A2, excerpt 90 regarding two-day malfunction notice and 45-day affirmative defense requirements.

Commenter Name: LESLIE SUE RITTS

Commenter Affiliation: National Environmental Development Association's Clean Air Project (NEDA/CAP)

Document Control Number: EPA-HQ-OAR-2002-0058-3529-A1

Comment Excerpt Number: 14

Comment: Subpar .(7) of the affirmative defense requires that an owner operator establish by a preponderance of the evidence that “*all of the actions in response to the excess emissions were documented by properly signed, contemporaneous operating logs.*” NEDA/CAP believes that this regulatory requirement should be deleted because during emergency situations, particularly when there is danger to life and property from malfunctioning equipment, operators worry about equipment failure and lives, not keeping logs. Alternatively EPA could clarify or define contemporaneous as within 24 hours of resolution of a malfunction.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 87 regarding use of technology for recordkeeping and reporting.

Commenter Name: Kerry Kelly

Commenter Affiliation: Waste Management (WM)

Document Control Number: EPA-HQ-OAR-2002-0058-3681-A2

Comment Excerpt Number: 31

Comment: We also believe the notification requirements should be streamlined. The initial two-day notification should include telephone, facsimile or e-mail. Facsimile communications are rarely used having been essentially replaced by email correspondence. Email notifications are simple and direct, and can be tracked easily and archived for recordkeeping purposes. WM recommends that the initial two-day notification should include a brief summary of the nature of the malfunction, corrective action taken and root cause analysis. Often the initial notification will

include enough information for the regulators to confirm a malfunction meets the criteria. For example, a lightning strike on a utility interconnect transformer that causes a temporary facility power outage would be easily discernible as a malfunction. If the agency needed more information, it could request a full report in 45 days, or ask the facility to include a full report in the next semiannual compliance report. Such streamlined requirements for malfunction events would be consistent with several states' requirements and would ensure ample regulatory oversight.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 87 regarding use of technology for recordkeeping and reporting.

Commenter Name: Melvin E. Keener

Commenter Affiliation: Coalition for Responsible Waste Incineration (CRWI)

Document Control Number: EPA-HQ-OAR-2002-0058-3454-A1

Comment Excerpt Number: 10

Comment: To many engineers, the term "root cause analysis" implies a specific formal process. For many malfunctions, the cause is immediately obvious and a formal process for determining the cause is not needed. When a malfunction occurs, the expectation is that the facility will correct the problem as quickly as possible and return to their operating window. A formal root cause analysis is typically limited to very significant events or repeat events. For example, if a thermocouple fails, the most likely cause is a bad thermocouple. The first response is to simply replace the thermocouple. However, if a second thermocouple fails within a short period of time, then something else may be causing that event to happen and a more detailed analysis may be needed. It may take several failures before the real cause is identified. Here a formal root cause analysis may be needed, but it certainly is not needed to replace the first failed thermocouple. The proposed language assumes that all malfunctions are equally significant and need an identical degree of investigation. For example, a missing data point due to a malfunction of the data acquisition system is not as significant as a power failure or a catastrophic event such as fire or explosion. CRWI believes that a formal root cause analysis should only be used when other reasonable methods fail to show what caused the malfunction or when the serious nature of an event might make such an analysis necessary. Moreover, other tools may be more appropriate (e.g., failure mode and effect, fault tree, etc.) or more powerful tools may be introduced in the future. The facility is the only one that can and should decide what tool to use to determine the cause of the malfunction.

Part of this problem may be in communications. To some companies and potentially to some local regulators, the term "root cause analysis" implies a specific formal process. There are several techniques that may be called "root cause analysis," depending on the author and industry. If EPA intends for the facility to investigate and fix the source of the malfunction so that it is less likely to recur, CRWI supports that concept but suggests that the Agency use an alternative term that does not carry a specific meaning. However, if the Agency envisions a formal process for determining the root cause for every malfunction, no matter how simple, CRWI believes this is unnecessary and would result in excess efforts with no environmental gains.

Response: The EPA did not intend to prescribe a specific methodology, given that “root cause analysis” is not a defined term in the rule. The EPA believes it has provided clear criteria within the affirmative defense provisions to support the development of an affirmative defense report. The EPA believes that these provisions will result in a minor administrative burden, but will result in sources analyzing their violation emissions to reduce or avoid those emissions in the future, which is an environmental benefit. A root cause analysis is not mandatory and is only required if a source seeks to assert an affirmative defense. However, such an analysis is beneficial in resolving or preventing violations and excess emissions whether the source seeks to assert the affirmative defense or not. A root cause analysis is one example of what constitutes good air pollution control practices to minimize emissions. A root cause analysis is not required for every malfunction, it is *only required* for those malfunctions for which the source chooses to assert an affirmative defense.

Commenter Name: Russell A. Wozniak

Commenter Affiliation: The Dow Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3449-A1

Comment Excerpt Number: 25

Comment: 40 CFR §63.7501 (a)(9) A written root cause analysis has been prepared, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the excess emissions resulting from the malfunction event at issue. The analysis must also specify, using best monitoring methods and engineering judgment, the amount of excess emissions that were the result of the malfunction.

~~40 CFR §63.7501 (a)(9) A written root cause analysis has been prepared, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the excess emissions resulting from the malfunction event at issue. The analysis must also specify, using best monitoring methods and engineering judgment, the amount of excess emissions that were the result of the malfunction.~~

Dow Comment: EPA should not require preparation and submission of a formal root cause analysis as this would have a chilling effect on internal communications regarding the root cause investigation and would detract from the goal of ensuring a candid inquiry into the event. The cause of even smaller malfunction events is routinely investigated within the industry, and no regulation is necessary to require this to happen.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3454-A1, excerpt 10 regarding root cause analysis requirement.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 105

Comment: Requirement (a)(9) is problematic in that it requires a party to prepare a “written root cause analysis to determine, correct and eliminate the primary causes of the malfunction and the excess emissions resulting from the malfunction event at issue.” This directive assumes that the cause of any and all malfunctions can be determined, corrected and eliminated. If a malfunction by definition is unavoidable, unforeseeable, and not reasonably preventable, it may be that the first time it happens its primary cause cannot be determined. If the cause cannot be determined, it cannot be corrected. So unless a party can figure out why something malfunctioned, it cannot claim to have had a “malfunction.” Not only is this nonsensical, it is a significant departure in EPA policy with no justification provided. For example, in the General Provisions applicable to New Source Performance Standards (NSPS), EPA recognizes that the cause of a malfunction cannot always be known. *See*, 40 CFR 60.7(b)(2) which requires that written reports of excess emissions include the “nature and cause of any malfunction, *if known...*” (Emphasis added.) Lastly, requiring a party to eliminate the primary causes of the malfunction, without regard to “taking into consideration the cost of achieving such” elimination and the “non-air quality health and environmental impacts and energy requirements” associated with its elimination is unreasonable and entirely inconsistent with the criteria for standards established under § 112(d) of the CAA.³³ [Footnote 33: For example, it might be theoretically possible to eliminate the excess emissions associated with the malfunction by installing totally redundant pollution control equipment, or pollution control equipment with far more capacity than needed for normal operations. But this would not reflect the performance of the best performers on which the MACT “floor” is to be based, nor would it appear to take cost and other factors into consideration as the statute requires for beyond-the-floor MACT standards. Moreover, the proposed requirement to eliminate “the primary causes of the malfunction” and not just to eliminate “the excess emissions resulting from the malfunction event” lies entirely outside of EPA’s authority under the CAA, which is limited to establishing and enforcing emission limitations, not dictating plant operations.]

Response: See the response to comment EPA-HQ-OAR-2002-0058-3454-A1, excerpt 10 regarding root cause analysis requirement.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 82

Comment: §63.7501(a)(1)(ii) and (iii) are vague, subjective and potentially impossible criteria to meet. Once an event occurs, you may learn enough to realize that you “could” have prevented it. In fact, that is the very basis for the later requirement to do a root cause analysis (RCA) – so a facility can identify the root cause and plan to prevent such events. Even being hit by a meteor would fail this test, since one theoretically could have planned for it, even if the chance of such an occurrence is infinitesimal. In short, these demonstration requirements are so vague and subjective as to make the affirmative defense potentially unavailable and applicable only at the whim of the interpreting regulator.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3454-A1, excerpt 10 regarding root cause analysis requirement.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 89

Comment: Proposed §63.7501(a)(9):

A written root cause analysis has been prepared, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the excess emissions resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of excess emissions that were the result of the malfunction.

EPA should clarify that the requirement to perform a RCA "to determine, correct, and eliminate the primary causes of the malfunction" does not require that identified corrective actions be completed within the demonstration period. Long-term corrective action can require facility modifications that can take months to years to design and execute or procedural changes that can take weeks to months to safely implement.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3454-A1, excerpt 10 regarding root cause analysis requirement.

Commenter Name: Lee Zeugin and Lauren Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1

Comment Excerpt Number: 19

Comment: Specifying work practice standards for malfunctions is more consistent with the CAA, and the D.C. Circuit's interpretation of it in *Sierra Club*, than EPA's proposed affirmative defense. Although the court found that the existing "general duty to minimize emissions" was not sufficient to qualify as a § 112(d) standard, and that EPA had "not purported to act under section 112(h)," it also made clear that the CAA *does not require* that the same standard apply to all periods. *Id.* at 1021 (recognizing that "continuous" under CAA § 302(k) does not mean "unchanging"), 1028. In short, nothing prohibits EPA from establishing § 112(h) standards for periods that include a malfunction, even if § 112(d) standards apply at other times. In fact, establishing § 112(h) standards for malfunctions would be more consistent with the *Sierra Club* ruling than applying clearly unachievable standards and allowing a defense to penalties, since an unachievable § 112 standard is not "section 112-compliant." It also would be more consistent with Congressional intent. By allowing work practice and other requirements under § 112(h), Congress clearly intended that sources be *provided the opportunity to be fully in compliance with some standard at all times*. Nothing in § 112 suggests that Congress intended to require a source owner or operator to certify "violation" of a § 112 standard as a result of an event the source could not reasonably control. EPA should adhere to that intent and specify reasonable work practice or operational requirements for periods of malfunctions.

Response: The affirmative defense criteria are not requirements that a source must meet. In an action to enforce a violation of a standard caused by a malfunction, a source can choose to assert

an affirmative defense. The affirmative defense is not relevant to malfunctions that do not result in violations of emission standards.

The EPA has determined that CAA section 112 does not require that emissions that occur during periods of malfunction be factored into development of CAA section 112 standards. As the EPA further explained, accounting for malfunctions would be difficult, if not impossible, given the myriad different types of malfunctions that can occur across all sources in the category and given the difficulties associated with predicting or accounting for the frequency, degree, and duration of various malfunctions that might occur. Setting work practice standards under section 112 presents the same issues as setting numerical emission limits given the varied nature of malfunctions. Thus EPA does not agree with commenter's suggestion that EPA apply work practices for malfunction events.

Commenter Name: Timothy Serie

Commenter Affiliation: American Coatings Association (ACA)

Document Control Number: EPA-HQ-OAR-2002-0058-3502-A1

Comment Excerpt Number: 23

Comment: *Affirmative Defense Provisions During Malfunctions*

ACA believes that EPA's approach to malfunction episodes including the proposed affirmative defense for violating an emissions standard during a malfunction episode is inconsistent with the Clean Air Act (CAA), and EPA should address this issue by promulgating a separate standard for malfunction periods. In the proposed reconsideration EPA plans to apply the emissions standards, which were calculated during periods of normal operation, at all times, including during a malfunction event. EPA is seeking comment on an affirmative defense provision requiring the owner or operator of a boiler to meet a list of criteria during a malfunction episode, and failing to meet these criteria exposes the source to potential civil penalties for violating the emissions standards. This approach, including the proposed affirmative defense, is inappropriate for the following reasons.

EPA fails to provide an adequate legal justification or explain why the emission standard that applies during normal operations should also apply during an unexpected malfunction period, even though the Agency did not consider malfunction periods when calculating and establishing the MACT requirements for this source category. Under the CAA § 112(d)(3), EPA must calculate and promulgate emissions standards that are achievable by the best performing existing sources. When calculating this emissions level, however, EPA did not consider the potential for malfunctions or how these events would affect achievable emissions levels. Therefore, during a malfunction episode, the Agency cannot expect affected sources to meet the emissions limits that were calculated during normal periods of operation. The Agency's approach in this regard is contrary to the CAA § 112(d).

Response: EPA recognizes that even equipment that is properly designed and maintained can sometimes fail and that such failure can sometimes cause an exceedance of the relevant emission standard. (See, e.g., State Implementation Plans: Policy Regarding Excessive Emissions During Malfunctions, Startup, and Shutdown (Sept. 20, 1999); Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions (Feb. 15, 1983)). EPA, therefore, added an

affirmative defense to civil penalties for exceedances of numerical emission limits that are caused by malfunctions. The affirmative defense criteria are not requirements that a source must meet. In an action to enforce a violation of a standard caused by a malfunction, a source can choose to assert an affirmative defense. The affirmative defense is not relevant to malfunctions that do not result in violations of emission standards.

EPA disagrees with comments that criticize the affirmative defense criteria as being overly vague or unduly restrictive and complex. The EPA believes that courts are well equipped and often do evaluate and apply the type of criteria set forth in the affirmative defense. Many of the conditions were modeled after the conditions of the affirmative defense in the EPA's SIP SSM policy, which several states have adopted into their SIPs. (See, e.g., State Implementation Plans: Policy Regarding Excessive Emissions During Malfunctions, Startup, and Shutdown (Sept. 20, 1999); Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions (Feb. 15, 1983)). We do not have any indication that parties to enforcement proceedings have had any significant difficulties applying the terms of these SIP affirmative defenses. In addition, the EPA's view is that use of consistent terms in establishing affirmative defense regulations and policies across various CAA programs will promote consistent implementation of those rules and policies.

EPA explained its view that a formal approach of an affirmative defense was preferable to an informal enforcement discretion approach for the following reasons: "First, the existence of a formal process better informs the public of the policy and factual issues which will underline enforcement of the standards. Second, affected industries which are making good-faith efforts to meet the standards will on the whole welcome a regularized means of informing the Agency in detail of the circumstances surrounding unavoidable emission excesses. Third, the Agency expects to benefit substantially from the information it will gain about the operation of the processes in question, for both future enforcement and standard setting." 37 Fed. Reg. 17,214, 17,214-15 (Aug. 25, 1972). The affirmative defense is not an informal enforcement discretion approach of the type that EPA rejected in 1972 and provides the benefits associated with the formalized approach that EPA identified in its 1972 proposal. See, *Mont. Sulphur & Chem. Co. v. United States EPA*, 2012 U.S. App. LEXIS 1056 (5th cir. Jan 19, 2012)(in rejecting industry argument that reliance on the affirmative defense was not adequate, court stated "[h]owever, here the EPA does not rely on enforcement discretion alone, but specifically promulgates an affirmative defense in the FIP, which clearly defines the requirements to avoid penalties.").

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 51

Comment: Although EPA has eliminated its unlawful compliance exemption for periods of startup, shutdown, and malfunction, the agency's final rule includes an "affirmative defense to penalties that purports to bar courts from imposing any penalties on sources that violate their emission standards during a malfunction and satisfy certain agency created conditions related to preventing malfunctions and controlling malfunction emissions. 76 Fed. Reg. at 80615. See 76 Fed. Reg. at 15642.

Response: The EPA has determined that CAA section 112 does not require that emissions that occur during periods of malfunction be factored into development of CAA section 112 standards. As the EPA further explained, accounting for malfunctions would be difficult, if not impossible, given the myriad different types of malfunctions that can occur across all sources in the category and given the difficulties associated with predicting or accounting for the frequency, degree, and duration of various malfunctions that might occur. Setting work practice standards under section 112 presents the same issues as setting numerical emission limits given the varied nature of malfunctions. Thus EPA does not agree with commenter's suggestion that EPA apply work practices for malfunction events. EPA recognizes that even equipment that is properly designed and maintained can sometimes fail and that such failure can sometimes cause an exceedance of the relevant emission standard. (See, e.g., State Implementation Plans: Policy Regarding Excessive Emissions During Malfunctions, Startup, and Shutdown (Sept. 20, 1999); Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions (Feb. 15, 1983)). EPA, therefore, added an affirmative defense to civil penalties for exceedances of numerical emission limits that are caused by malfunctions. The affirmative defense criteria are not requirements that a source must meet. In an action to enforce a violation of a standard caused by a malfunction, a source can choose to assert an affirmative defense. The affirmative defense is not relevant to malfunctions that do not result in violations of emission standards.

EPA disagrees with comments that criticize the affirmative defense criteria as being overly vague or unduly restrictive and complex. The EPA believes that courts are well equipped and often do evaluate and apply the type of criteria set forth in the affirmative defense. Many of the conditions were modeled after the conditions of the affirmative defense in the EPA's SIP SSM policy, which several states have adopted into their SIPs. (See, e.g., State Implementation Plans: Policy Regarding Excessive Emissions During Malfunctions, Startup, and Shutdown (Sept. 20, 1999); Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions (Feb. 15, 1983)). We do not have any indication that parties to enforcement proceedings have had any significant difficulties applying the terms of these SIP affirmative defenses. In addition, the EPA's view is that use of consistent terms in establishing affirmative defense regulations and policies across various CAA programs will promote consistent implementation of those rules and policies.

EPA explained its view that a formal approach of an affirmative defense was preferable to an informal enforcement discretion approach for the following reasons: "First, the existence of a formal process better informs the public of the policy and factual issues which will underline enforcement of the standards. Second, affected industries which are making good-faith efforts to meet the standards will on the whole welcome a regularized means of informing the Agency in detail of the circumstances surrounding unavoidable emission excesses. Third, the Agency expects to benefit substantially from the information it will gain about the operation of the processes in question, for both future enforcement and standard setting." 37 Fed. Reg. 17,214, 17,214-15 (Aug. 25, 1972). The affirmative defense is not an informal enforcement discretion approach of the type that EPA rejected in 1972 and provides the benefits associated with the formalized approach that EPA identified in its 1972 proposal. See, *Mont. Sulphur & Chem. Co. v. United States EPA*, 2012 U.S. App. LEXIS 1056 (5th cir. Jan 19, 2012)(in rejecting industry argument that reliance on the affirmative defense was not adequate, court stated "[h]owever, here the EPA does not rely on enforcement discretion alone, but specifically promulgates an affirmative defense in the FIP, which clearly defines the requirements to avoid penalties.").

Commenter Name: Jennifer Youngblood
Commenter Affiliation: National Tribal Air Association
Document Control Number: EPA-HQ-OAR-2002-0058-3667-A2
Comment Excerpt Number: 22

Comment: EPA Is required to take malfunctions into account when adopting BPH emission limits, either by including them in the data used to develop the emission limitation that applies to normal operations or by treating any emission limitation that does not consider malfunctions as a beyond-the-floor limit and providing all the required regulatory analysis needed to support such a conclusion for comment.

EPA says it “has determined that malfunctions should not be viewed as a distinct operating mode.”⁴⁰ Since, as defined in §63.2, a malfunction must result in “excess” emissions, and to be “excess” emissions must exceed the emissions that occur during normal operations, it is clear that an emission occurrence cannot be both a malfunction and normal operations. EPA made this clear in the preamble to the original finalized part 63 General Provisions⁴¹ where they stated “Excess emissions occur during [SSM] when air pollution is emitted in quantities greater than anticipated by the applicable standard. . . . Excess emissions are typically direct indications of noncompliance with the emission standard and, therefore, are directly enforceable.” Thus, EPA has been clear that excess emissions, a malfunction criterion, can only occur when emissions exceed the emission limit for normal operations.

The natural outgrowth of the new position that malfunctions are normal operations is to consider malfunctions in developing the emission limit for normal operations. Yet, EPA concludes the opposite but offers no explanation of its contradictory positions that malfunctions are normal operations, but should not be considered in developing the emission limitations applicable during normal operations. In fact, EPA specifically draws the illogical conclusion that since malfunctions are normal operations “any emissions that occur at such times do not need to be factored into development of CAA section 112(d) standards, which, once promulgated, apply at all times.”⁴² Once again no explanation is provided for this nonsensical statement.

[Footnote 40: 76 Fed. Reg. 15613 (March 21, 2011)]

[Footnote 41: 59 Fed. Reg. Preamble Section IV.F.1, (March 16, 1994)]

[Footnote 42: 76 Fed. Reg. 15613 (March 21, 2011)]

Response: The commenter appears to have misinterpreted EPA’s explanation for its approach to malfunctions and to have confused several concepts. As explained in the preamble, EPA has determined that CAA section 112 does not require that emissions that occur during periods of malfunction be factored into development of CAA section 112 standards. EPA’s position is not that “malfunctions *are* normal operations” as commenter claims. During periods of malfunction, the otherwise applicable standard applies. Specifically, if a malfunction occurs during a period of startup or shutdown and the standard for startup or shutdown is different than the standard during normal operations, then the standard that applies during that malfunction is the startup or shutdown standard.

Further, 40 CFR 63.2 defines malfunctions a type of failure of equipment or process which causes, or have the potential to cause, “the emissions limitations” in an applicable standard to be exceeded, and does not refer to the emission limit “for normal operations” as commenter suggests. EPA included this limitation in the definition of malfunction to ensure that minor or routine events need not be addressed by SSM plans or reported to the Agency. 68 Fed. Reg. 32592 (May 30, 2003). Nothing in the definition of malfunction contradicts EPA’s rationale for its approach to malfunctions.

Commenter Name: Russell A. Wozniak

Commenter Affiliation: The Dow Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3449-A1

Comment Excerpt Number: 21

Comment: For malfunctions that result in only small levels of excess HAP emissions, instead of requiring the regulated entity to establish and prove an affirmative defense, EPA should establish a work practice requirement that requires the owner/operator to stop the emissions, stop the malfunction, and to return to normal operations as soon as practical. For example, if a CO concentration limit is exceeded as a result of a fuel system malfunction, but is quickly corrected (e.g. within 1 to 2 hours), then the owner/operator should not have to go through the exercise of asserting an affirmative defense.

Response: See the responses to comments EPA-HQ-OAR-2002-0058-3500-A1, excerpt 19 and EPA-HQ-OAR-2002-0058-3502-A1, excerpt 23 regarding establishing work practice standards for malfunctions.

Commenter Name: Bruce W. Ramme

Commenter Affiliation: Wisconsin Electric Power Company (WE Energies)

Document Control Number: EPA-HQ-OAR-2002-0058-3452-A1

Comment Excerpt Number: 8

Comment: We propose that owners and operators be able to utilize an exemption for malfunctions if:

(1) they maintain records documenting that the event in question met the definition of a malfunction contained in 40 CFR 63.2, the owner and/or operator took steps to minimize emissions during the malfunction to the extent practicable, and the owner and/or operator took reasonable actions designed to minimize the possibility that this type of event will occur in the future; and

(2) they report the malfunction event in their annual or biennial compliance report. Maintenance of such records would generally be required under proposed 40 CFR 63.7555(d)(7) and (8) of the proposed rule and compliance reporting would be required under 40 CFR 63.7550. To the extent that the recordkeeping and reporting requirements described above are met for a malfunction event, that event should be presumed to be a malfunction and exempt from the emission limitations of the rule without the need for the owner or operator to present information in affirmative defense of an enforcement proceeding.

Response: See the responses to comments EPA-HQ-OAR-2002-0058-3500-A1, excerpt 19 and EPA-HQ-OAR-2002-0058-3502-A1, excerpt 23 regarding establishing work practice standards for malfunctions.

Commenter Name: Melvin E. Keener

Commenter Affiliation: Coalition for Responsible Waste Incineration (CRWI)

Document Control Number: EPA-HQ-OAR-2002-0058-3454-A1

Comment Excerpt Number: 13

Comment: CRWI believes that not allowing an affirmative defense in an action for injunctive relief is arbitrary and capricious. As the D.C. Circuit Court stated in *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973) a case reviewing a § 111 rule, the court held that startup, shutdown, or malfunction ("SSM") provisions are "necessary to preserve the reasonableness of the standards as a whole." The D.C. Circuit Court of Appeals has also noted that "[a] technology-based standard discards its fundamental premise when it ignores the limits inherent in the technology." *NRDC v. EPA*, 859 F.2d 156, 208 (D.C. Cir. 1988). Therefore, EPA should not apply a policy drafted to "ensure that SIPs provide for attainment and maintenance of the national ambient air quality standards ("NAAQS") and protection of prevention of significant deterioration (PSD) increments" and other risk-based programs, SIP SSM Memo at 2, to the CAA § 129 technology-based program.

Response: See the responses to comments EPA-HQ-OAR-2002-0058-3500-A1, excerpt 19 and EPA-HQ-OAR-2002-0058-3502-A1, excerpt 23 regarding establishing work practice standards for malfunctions.

Commenter Name: Robert Cleaves

Commenter Affiliation: Biomass Power Association (BPA) and California Biomass Energy Alliance (CBEA)

Document Control Number: EPA-HQ-OAR-2002-0058-3489-A1

Comment Excerpt Number: 5

Comment: Even the best designed and operated boiler systems will occasionally malfunction. In the technology based Boiler MACT mles, EPA should not burden boiler operators with non-compliance and all its potential ramifications for events not entirely under their control. Instead EPA should instead set a work practice standard for such periods.

Response: See the responses to comments EPA-HQ-OAR-2002-0058-3500-A1, excerpt 19 and EPA-HQ-OAR-2002-0058-3502-A1, excerpt 23 regarding establishing work practice standards for malfunctions.

Commenter Name: Kevin G. Desharnais, Attorney, Mayer Brown LLP

Commenter Affiliation: United States Sugar Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3496-A1

Comment Excerpt Number: 2

Comment: The CAA allows the enactment of work practice standards whenever "it is not feasible in the judgment of the Administrator to prescribe or enforce an emission standard for control of a hazardous air pollutant or pollutants." 42 U.S.C. § 7412(h)(1). This is the case for malfunctions. As EPA acknowledged, "even equipment that is properly designed and maintained can sometimes fail" and "cause an exceedance of the relevant emission standard." 76 Fed. Reg. at 15613. In the case of bagasse boilers, many of the malfunctions stem from variations in the physical properties of the cane itself, which can be affected by factors beyond the control of the operator, such as cane variety, cane quality (*e.g.*, early take out VB, second or third ratoon cane), and environmental factors (*e.g.*, weather, seasonal variation, moisture level, freeze damage). The variable nature of the fuel can in turn cause mechanical difficulties, and sugar mill boilers routinely experience significant fluctuations in operations that are beyond the reasonable control of the boiler and sugar mill operators. Therefore, "it would be difficult to set a standard that takes into account the myriad different types of malfunctions that can occur across all sources in the category." *Id.* This is precisely the context in which a work practice standard is most effective.

U.S. Sugar requests EPA reconsider its use of an affirmative defense for malfunction events and instead develop a feasible work practice standard.

Response: See the responses to comments EPA-HQ-OAR-2002-0058-3500-A1, excerpt 19 and EPA-HQ-OAR-2002-0058-3502-A1, excerpt 23 regarding establishing work practice standards for malfunctions.

Commenter Name: Lee Zeugin and Lauren Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1

Comment Excerpt Number: 17

Comment: The CAA does not require EPA to apply numerical emission standards to all operating periods. CAA § 112(h)(4) only requires numerical emission standards if it "is feasible" to promulgate and enforce them. If it is "not feasible" in the "judgment of the Administrator" to prescribe or enforce an emission standard, CAA § 112(h)(4) allows EPA to promulgate "design, equipment, work practice, or operational standards, or a combination thereof," instead. Infeasibility includes situations where emissions cannot be measured due to "technological and economic limitations." CAA § 112(h)(2)(B).

EPA acknowledges that even properly designed and maintained equipment can fail. 76 Fed. Reg. at 15,642. However, rather than make a determination whether or not it is "feasible" to prescribe emission standards for these periods, as § 112(h)(1) and (4) seem to contemplate, EPA chooses to ignore such periods in the standard setting process. Specifically, EPA concludes that malfunctions should "not be viewed as a distinct operating mode" and therefore, "emissions that occur at such times do not need to be factored into development of CAA section 112(d) standards." *Id.* Because EPA does not factor malfunctions (even malfunctions of "best performing" sources) into its proposed standards, it is unlikely the standards will be achievable if a significant malfunction occurs.

Response: See the responses to comments EPA-HQ-OAR-2002-0058-3500-A1, excerpt 19 and EPA-HQ-OAR-2002-0058-3502-A1, excerpt 23 regarding establishing work practice standards for malfunctions.

Commenter Name: Lee Zeugin and Lauren Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1

Comment Excerpt Number: 18

Comment: UARG agrees with EPA that equipment can and will fail unexpectedly, and that some allowance must be made for periods of malfunction. Application of numerical limits to such malfunctions without a defense to penalties clearly would violate the Due Process Clause and the Eighth Amendment prohibition on Cruel and Unusual Punishment.¹³ Although UARG appreciates EPA’s willingness to exercise enforcement discretion and to provide a defense to civil penalties, EPA’s refusal to take malfunctions into account when setting standards is not reasonable. Section 112 does not limit EPA’s standard setting obligation to “distinct operating modes.” As the D.C. Circuit ruled in *Sierra Club v. EPA*, CAA § 112 requires that some “section 112-compliant standard” apply at all times (not just during distinct operating modes). 551 F.3d 1019, 1027 (D.C. Cir. 2008). If EPA has determined that it is not technologically or economically “feasible” to gather emissions data necessary to establish numerical emissions standards that “take malfunctions into account,” EPA should promulgate operational and work practice standards as § 112(h) specifies. To the extent EPA is attempting to distinguish between the “impracticality” of taking malfunctions into account, and the “infeasibility” of prescribing and enforcing standards for such events, EPA’s position is difficult to square with the Act.

[Footnote]

(13) See UARG Comments on the Supplemental Proposal on Parts 70 and 71 of the Operating Permits Program, 60 Fed. Reg. 45,530 (August 31, 1995) (October 30, 1995) at 49-59 (incorporated by reference).

Response: See the responses to comments EPA-HQ-OAR-2002-0058-3500-A1, excerpt 19 and EPA-HQ-OAR-2002-0058-3502-A1, excerpt 23 regarding establishing work practice standards for malfunctions.

Commenter Name: Timothy Serie

Commenter Affiliation: American Coatings Association (ACA)

Document Control Number: EPA-HQ-OAR-2002-0058-3502-A1

Comment Excerpt Number: 24

Comment: The affirmative defense is not an adequate replacement for standards during malfunction episodes and EPA should establish a separate standard for periods of malfunction. The affirmative defense provisions do not remedy the underlying problems with the Agency’s approach to malfunction periods. Furthermore, it would likely be impractical for the Agency to recalculate the entire standard and account for malfunctions. Instead, EPA should break down the standard and establish different requirements for periods of malfunction. This approach realizes the limitations of control technology and its effect on emissions levels, and also satisfies

the court's decision in *Sierra Club v. EPA*, 551 F.3d 1019 (D.C. Cir. 2008), by ensuring that standards (even though there may be multiple different standards) are in place at all times during periods of startup, shutdown, and malfunction.

Response: See the responses to comments EPA-HQ-OAR-2002-0058-3500-A1, excerpt 19 and EPA-HQ-OAR-2002-0058-3502-A1, excerpt 23 regarding establishing work practice standards for malfunctions.

Commenter Name: David A. Buff, Golder Associates Inc.
Commenter Affiliation: Florida Sugar Industry (FSI)
Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1
Comment Excerpt Number: 49

Comment: Instead of establishing an affirmative defense, EPA should establish work practice standards to address emissions during periods of malfunction.

Response: See the responses to comments EPA-HQ-OAR-2002-0058-3500-A1, excerpt 19 and EPA-HQ-OAR-2002-0058-3502-A1, excerpt 23 regarding establishing work practice standards for malfunctions.

Commenter Name: Lorraine Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1
Comment Excerpt Number: 84

Comment: AFFIRMATIVE DEFENSE PROVISIONS DURING MALFUNCTIONS

In the Final Boiler Rule, EPA for the first time stated that boilers and process heaters would be required to comply at all times with emission limitations derived from and established for normal operations, even during periods of malfunction. This is contrary to a long history of recognition by EPA and the courts that technology-based emission standards and requirements established in NESHAP and new source performance standard (NSPS) rules need to account for unavoidable excess emissions associated with malfunctions. EPA now chooses to disregard its historical position and instead proposes an "affirmative defense" that may be available to avoid civil penalties (but not other relief available under the CAA) for emission exceedances associated with malfunctions. The affirmative defense provisions appear in § 63.7501 of the final rule and require an owner/operator of a major source boiler or process heater to prove by a preponderance of evidence that it has met each and every requirement in order to avail itself of the affirmative defense to a claim for civil penalties. ACC believes that EPA should abandon the approach it is taking to addressing malfunctions, that is, offering an affirmative defense, and instead should use its statutory authority in § 112(h) to establish a work practice or operational standard that would reduce emissions during a malfunction event.

Response: See the responses to comments EPA-HQ-OAR-2002-0058-3500-A1, excerpt 19 and EPA-HQ-OAR-2002-0058-3502-A1, excerpt 23 regarding establishing work practice standards for malfunctions.

Commenter Name: Lorraine Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1
Comment Excerpt Number: 85

Comment: *EPA has Misinterpreted the Holding In Sierra Club.*

As noted above, EPA believes that requiring sources to comply with numeric emission standards established for normal operations even during a malfunction event, is "consistent with *Sierra Club v. EPA*." The D.C. Circuit's *Sierra Club* decision does not, however, compel or even support EPA's position that the same numeric standards established for normal operations must also apply during a malfunction event.

Response: See the responses to comments EPA-HQ-OAR-2002-0058-3500-A1, excerpt 19 and EPA-HQ-OAR-2002-0058-3502-A1, excerpt 23 regarding establishing work practice standards for malfunctions.

Commenter Name: Lorraine Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1
Comment Excerpt Number: 86

Comment: The *Sierra Club* ruling vacated the exemption for excess emissions during periods of startup, shutdown and malfunction (SSM) contained in the General Provisions, 40 C.F.R. part 63 subpart A, for emission standards for hazardous air pollutants regulated under CAA § 112. At issue was EPA's determination that excess emissions during periods of SSM experienced by major sources are not violations as long as the owner/operator has prepared a startup, shutdown and malfunction plan and complies with a "general duty" to minimize emissions. The court concluded that the "general duty" was not a "section 112-compliant standard." However, the court did not state nor even imply that the same emission limits that EPA establishes for normal operations must apply during SSM events.

In fact, the court clearly indicated that section 302(k)'s "inclusion of [the] broad phrase" "any requirement relating to the operation or maintenance of a source to assure continuous emission reduction" in the definition of "emission standard" suggests that EPA can establish MACT standards consistent with CAA section 112 "without necessarily continuously applying a single standard." 551 F.3d 1019, 1021. The court accepted that "continuous" for purposes of § 302(k) "does not mean unchanging...." *Id.* at 1021. The court also highlighted the fact that Congress recognized that it might not be feasible in all cases to prescribe or enforce a numeric emission standard. Congress therefore provided in § 112(h) for the establishment of a "work practice" or "operational standard." *Id.* at 1028.

Response: See the responses to comments EPA-HQ-OAR-2002-0058-3500-A1, excerpt 19 and EPA-HQ-OAR-2002-0058-3502-A1, excerpt 23 regarding establishing work practice standards for malfunctions.

Commenter Name: Lorraine Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1
Comment Excerpt Number: 87

Comment: EPA is now soliciting comments on its determination in the final rule that boilers and process heaters must meet the numeric emission standards established for steady-state operations at all times, including periods of malfunction, and that the only enforcement relief that may be available in the event of a malfunction is an "affirmative defense" to civil penalties. EPA is completely silent on why it is not exercising the discretion and authority provided by Congress in § 112(h) to address boiler and process heater malfunctions; in fact, it does not even mention that statutory authority in discussing malfunctions. If EPA wants to act "consistent with" the court's decision in *Sierra Club*, it should promulgate standards for periods of malfunction pursuant to its § 112(h) authority. If EPA chooses to reject the flexibility that Congress clearly intended the Agency to use when it is not feasible to prescribe or enforce a numeric emission standard, it needs to explain its legal authority for these affirmative defense requirements and why each of the requirements is reasonable and justified, taking into consideration alternative solutions.

Response: See the responses to comments EPA-HQ-OAR-2002-0058-3500-A1, excerpt 19 and EPA-HQ-OAR-2002-0058-3502-A1, excerpt 23 regarding establishing work practice standards for malfunctions.

Commenter Name: Lorraine Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1
Comment Excerpt Number: 89

Comment: *EPA Failed To Present Any Rationale or Justification for its Decision To Apply the Same Numeric Emission Standards Established for Normal Operations for an Abnormal Event, i.e., A Malfunction.*

As highlighted above, the court in *Sierra Club* did not state that EPA must apply the same standards it establishes for normal operations during periods of SSM. The court's holding is clear that "some" § 112 standard must "govern" SSM events but it did not specify which § 112 standard. In this rulemaking, EPA concluded that the numeric emission limitations established for normal operations also must be attained during a malfunction event. However, EPA has provided no explanation as to why it believes that boilers and process heaters reasonably could be expected to meet the emissions standards applicable to steady-state operations during a malfunction event.

EPA claims that it somehow "presents significant difficulties" to attribute malfunctions to a "best performing" source. *Id.* To the contrary, it "presents significant difficulties" when EPA ignores the undisputed existence of malfunctions even at best-performing sources, and claims falsely that the best-performing sources "achieve" emission levels that they undisputedly do not achieve part of the time. Since EPA describes malfunctions as being sometimes unavoidable or "not reasonably preventable," despite proper design and maintenance of equipment, there is no basis

for EPA's conclusion that malfunction events are not representative of best-performing sources. See 76 Fed. Reg. 15613. True, one goal (although not "the goal") "of best performing sources is to operate in such a way as to avoid malfunctions of their units." *Id.* But that is all the more reason why EPA must acknowledge the fact that those sources nevertheless experience malfunction events, rather than pretend otherwise.

[Footnote 30: See 40 C.F.R. § 60.8(c). For example, the D.C. Circuit recognized, in *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 398 (D.C. Cir. 1973), a decision reviewing standards under CAA section 111, that "'start-up' and 'upset' conditions due to plant or emission device malfunction, is an inescapable aspect of industrial life and that allowance must be made for such factors in the standards that are promulgated." *Id.* at 399. Similarly, in *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 432 (D.C. Cir. 1973), *cert. denied*, 416 U.S. 969 (1974), another section 111 case, the court held that SSM provisions are "necessary to preserve the reasonableness of the standards as a whole." *Id.* at 433. In *National Lime Ass'n v. EPA*, 627 F.2d 416 (D.C. Cir. 1980), another case reviewing emission standards promulgated under CAA section 111, the court held that the CAA requirement that NSPS be "achievable" means that the standards must be capable of being met "on a regular basis," including "under most adverse circumstances which can reasonably be expected to recur," including during periods of SSM. 627 F.2d at 431 n.46. See also *Marathon Oil Co. v. EPA*, 564 F.2d 1253, 1273-74 (9th Cir. 1977); *NRDC v. EPA*, 859 F.2d 156, 207-208 (D.C. Cir. 1988) (similar conclusion when considering analogous Clean Water Act requirements).]

Response: See the responses to comments EPA-HQ-OAR-2002-0058-3500-A1, excerpt 19 and EPA-HQ-OAR-2002-0058-3502-A1, excerpt 23 regarding establishing work practice standards for malfunctions.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 90

Comment: EPA should look to the "best performing" sources to establish the appropriate § 112(h) work practice standards for a malfunction event. After all, a work practice standard like a numeric emission standard must be based on the emission reductions achieved by the best performing sources.

In failing to articulate the basis for its decision, the Agency also ignores the comments submitted by ACC and others strongly advocating for EPA to establish a work practice standard for malfunction events. This is not reasoned decision-making and ACC hopes that the Agency's "reconsideration" of its affirmative defense approach will prompt EPA to give reasonable consideration to the fact that a boiler that has a malfunction is not likely to be able to achieve the same level of emission reductions that it achieved and can achieve while operating at steady-state.

Response: See the responses to comments EPA-HQ-OAR-2002-0058-3500-A1, excerpt 19 and EPA-HQ-OAR-2002-0058-3502-A1, excerpt 23 regarding establishing work practice standards for malfunctions.

Commenter Name: Lorraine Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1
Comment Excerpt Number: 92

Comment: EPA's offering of an affirmative defense does not bear a reasonable relationship to the purpose of § 112 or its requirement to establish standards that consider and address the reality of a potential malfunction of technology. If EPA chooses to reject the flexibility that Congress clearly intended the Agency to use when it is not feasible to prescribe or enforce a numeric emission standard, it needs to explain why its affirmative defense approach is a better alternative than using the statutory authority provided in § 112(h) to establish a work or management practice for a malfunction period.

Response: See the responses to comments EPA-HQ-OAR-2002-0058-3500-A1, excerpt 19 and EPA-HQ-OAR-2002-0058-3502-A1, excerpt 23 regarding establishing work practice standards for malfunctions. See the response to comment EPA-HQ-OAR-2002-0058-3667-A2, excerpt 22 regarding developing emission limits and malfunctions.

Commenter Name: Lorraine Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1
Comment Excerpt Number: 94

Comment: EPA cannot rationally defend its view that applying the concept of —best performing is somehow inconsistent with a source experiencing a malfunction. See 76 Fed. Reg.15613. This ignores that there are work practices – such as monitoring operating parameters to identify a malfunction and stopping or cutting back the process accordingly – that represent the best practices for minimizing emissions during a malfunction. While the measures that represent these best practices will depend on facility-specific issues, such as process design, pollution control train, and other factors, they nonetheless represent the "the maximum degree of reduction in emissions of the hazardous air pollutants...achievable...through application of measures, processes, methods, systems or techniques" and reflect "the emission control that is achieved in practice by the best controlled similar source[s]" CAA § 112(d)(2) and (3).

Response: See the responses to comments EPA-HQ-OAR-2002-0058-3500-A1, excerpt 19 and EPA-HQ-OAR-2002-0058-3502-A1, excerpt 23 regarding establishing work practice standards for malfunctions.

Commenter Name: Lorraine Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1
Comment Excerpt Number: 107

Comment: For all of the reasons above, and in keeping with the court's holding in *Sierra Club*, ACC strongly encourages the Agency to abandon its affirmative defense approach as an appropriate and legal way to address excess emissions during a malfunction, and instead to use

its authority in § 112(h) to establish an emission standard using a management practice, work practice or operational standard to reduce emissions during a malfunction of a boiler or process heater.

Response: See the responses to comments EPA-HQ-OAR-2002-0058-3500-A1, excerpt 19 and EPA-HQ-OAR-2002-0058-3502-A1, excerpt 23 regarding establishing work practice standards for malfunctions.

Commenter Name: Alicia Meads

Commenter Affiliation: National Association of Manufacturers (NAM)

Document Control Number: EPA-HQ-OAR-2002-0058-3515-A1

Comment Excerpt Number: 17

Comment: As the NAM has previously commented, the EPA should establish work practices to address emissions during periods of malfunction. Given that the EPA's floor data does not consider malfunctions and that the statute requires that the MACT standard be "achievable," The EPA should set work practice requirements to address periods of malfunctions as well. CAA Section 112(h) allows the EPA to set work practice standards for situations where "it is not feasible in the judgment of the Administrator to prescribe or enforce an emission standard" Malfunctions fit with the situations described in the definition of "not feasible to prescribe or enforce an emission standard" as any situation where "the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations." Emission testing for malfunctions would be near impossible to conduct given the sporadic and unpredictable nature of the events. Section 112(h) work practice standards, therefore, are well-suited to address malfunction periods and the complexities and challenges surrounding collecting data and establishing numerical standards for those events.

The NAM disagrees with the EPA's proposal to provide an affirmative defense for periods of malfunction. As has been discussed in various comments in this rulemaking, as well as others where the EPA has proposed a similar affirmative defense, the proposed affirmative defense is not a permissible substitute for setting emissions standards for periods of malfunction, and it is unreasonable and impracticable.

Response: See the responses to comments EPA-HQ-OAR-2002-0058-3500-A1, excerpt 19 and EPA-HQ-OAR-2002-0058-3502-A1, excerpt 23 regarding establishing work practice standards for malfunctions.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 117

Comment: EPA's proposal to provide an "affirmative defense" for periods of malfunction is without merit. EPA must instead establish work practices to address emissions during periods of malfunction. For these reasons, EPA should set aside the proposed affirmative defense for periods of malfunction and, instead, set a work practice standard for such periods.

Response: See the responses to comments EPA-HQ-OAR-2002-0058-3500-A1, excerpt 19 and EPA-HQ-OAR-2002-0058-3502-A1, excerpt 23 regarding establishing work practice standards for malfunctions.

Commenter Name: LESLIE SUE RITTS

Commenter Affiliation: National Environmental Development Association's Clean Air Project (NEDA/CAP)

Document Control Number: EPA-HQ-OAR-2002-0058-3529-A1

Comment Excerpt Number: 7

Comment: NEDA/Submits that the ICI MACT Outlaws Safety By Failing to Provide a Work Practice Standard for Boiler Malfunctions. Because EPA failed to take comment on the Affirmative Defense Provisions in the Final ICI MACT rule, codified at §63.7501, the December NPRM requests comment on the provisions. NEDA/CAP submits that the EPA has violated the Clean Air Act by failing to provide an “achievable” emission standard during malfunction events. While EPA recognizes that startup and shutdown are separate emission events that require establishment of work practice standards, the Agency determined that malfunctions should not be viewed as a distinct operating mode. 76 Fed. Reg. 15642. Therefore, the Agency determined that any emissions that occur at such times do not need to be factored into development of CAA section 112(d) standards, which, once promulgated, apply at all times and in the event that a source fails to comply with the applicable CAA section 112(d) standards as a result of a malfunction event EPA’s failure to provide an applicable standard during malfunction events outlaws good safety practices and violates CAA Section 112(d), which requires EPA to establish achievable MACT standards.

By requiring that a boiler meet the continuous emission limits during malfunctions, the ICI MACT Rule outlaws safety because it is not always possible to achieve emission limits during malfunction events. By doing so, EPA violated CAA Section 112(d)(4) by not providing for the development of work practice standards for malfunctions under CAA Section 112(h). The regulation must therefore be amended to provide for an applicable standard based on good work practices during unforeseeable and/or unavoidable malfunction events. EPA has provided no analysis showing that the best-performing, or MACT floor, boilers in each subcategory are capable of achieving the relevant emission limits during malfunction events.

Response: See the responses to comments EPA-HQ-OAR-2002-0058-3500-A1, excerpt 19 and EPA-HQ-OAR-2002-0058-3502-A1, excerpt 23 regarding establishing work practice standards for malfunctions.

Commenter Name: LESLIE SUE RITTS

Commenter Affiliation: National Environmental Development Association's Clean Air Project (NEDA/CAP)

Document Control Number: EPA-HQ-OAR-2002-0058-3529-A1

Comment Excerpt Number: 8

Comment: EPA and Courts recognize that malfunction events are inescapable aspects of technology. EPA has consistently recognized that it may be technically infeasible for industrial sources to comply at all times with technology-based pollution control standards, particularly

during periods of startup and shutdown and during periods of malfunction. See e.g. 40 CFR §60.8 (general exclusion from compliance with the New Source Performance Standards that became law in 1973). The Courts also have explicitly recognized that start-up and upset conditions due to plant or emission device malfunctions are “an inescapable aspect of industrial life and that allowance must be made for such factors in the standards that are promulgated.” *Portland Cement Ass’n v. Ruckelshaus*, 486 F.3d 375. At 398 (D.C. Cir 1973) (reviewing CAA Sec. 111); see also *National Lime Association v. EPA* 627 F.3d 416, 431 n. 46 (D.C. Cir. 1980) (reviewing CAA Sec. 111); *NRDC v. EPA* 859 F.2d 156, 208 (D.C. Cir 1988); (CAA); *Marathon Oil Co. v. EPA*, 564 F.2d 1253, 1273-1274) (9th Cir. 1977) (EPA violated Clean Water Act by failing to provide an upset provision to address effluent conditions beyond the control of the permit holder).

Response: See the responses to comments EPA-HQ-OAR-2002-0058-3500-A1, excerpt 19 and EPA-HQ-OAR-2002-0058-3502-A1, excerpt 23 regarding establishing work practice standards for malfunctions.

Commenter Name: LESLIE SUE RITTS

Commenter Affiliation: National Environmental Development Association's Clean Air Project (NEDA/CAP)

Document Control Number: EPA-HQ-OAR-2002-0058-3529-A1

Comment Excerpt Number: 9

Comment: *Sierra Club v. EPA* does not bar the Agency from establishing applicable work practice standards during malfunctions. EPA argues that not only does it have insufficient information on which to establish a standard during malfunction events, but it suggests that such a standard would be prohibited under *Sierra Club v. EPA*, 551 F. 3d 1019 (D.C. Cir. 2008), *cert. denied*, 130 S. Ct. 1735 (2010). *Sierra Club* only found, however, that EPA could not automatically excuse emission violations during malfunction events by referencing the general MACT provisions. The case notably did not address standards that established where emission limitations were not feasible to prescribe work practice standards. See A. Kushner, Letter to Counsel *Re: Vacatur of Startup, Shutdown, and Malfunction (SSM) Exemption (40 CFR §§ 63.6(f)(1) and 63.6(h))* (July 22, 2009). That letter states that “EPA recognizes, however, that some sources * * * may be unable to comply with such standards during SSM events despite their best efforts, including adherence to 40 CFR §63.3(e)(1)(i) (*general requirement to minimize emissions at all times including periods of SSM, consistent with safety and good air pollution control practices*). Therefore EPA stated that the Agency:

“Commits to evaluating concerns raised with respect to specific Section 112(d) source category standards where the Agency determines that sources within a source category may have a limited ability to comply with those standards during periods of SSM. EPA intends to give the highest priority to reviewing and revising those Section 112(d) source category standards that may be difficult for sources to meet during an SSM period given the technological limitations of the processes involved.”

Id. 4. NEDA/CAP therefore submits that the Agency was unreasonable in failing to establish a work practice standard that was applicable when ICI boilers malfunction. The Affirmative Defense Provisions in the Final ICI MACT rule are not a substitute for failing to provide for

work practice standards similar to those provided for startup and shutdown. Most importantly they fail to protect an operator from criminal penalties and injunctive relief when reacting to malfunctions that result in emissions in excess of MACT emissions limits in the effort to protect employee and community safety and property.

Response: See the responses to comments EPA-HQ-OAR-2002-0058-3500-A1, excerpt 19 and EPA-HQ-OAR-2002-0058-3502-A1, excerpt 23 regarding establishing work practice standards for malfunctions.

Commenter Name: LESLIE SUE RITTS

Commenter Affiliation: National Environmental Development Association's Clean Air Project (NEDA/CAP)

Document Control Number: EPA-HQ-OAR-2002-0058-3529-A1

Comment Excerpt Number: 10

Comment: The “affirmative defense” provision in the Final ICI MACT Rule contains arbitrary language because it is an enforcement policy; on this basis it would be arbitrary and capricious to codify it in the ICI MACT. In lieu of establishing a work practice standard during malfunction events, as EPA has done for “startups” and “shutdowns” the ICI MACT provides for an affirmative defense to civil penalties for emission violations that occur during malfunctions. The December 23, 2011 NPRM requests comment on affirmative defense provision. NEDA/CAP notes that the affirmative defense is *sub voce* recognition that malfunctions do occur and thus requires EPA to establish a standard based on work practices because the agency is not able to prescribe an enforceable emission limitation during malfunction events. CAA Section 112(h).

Response: See the responses to comments EPA-HQ-OAR-2002-0058-3500-A1, excerpt 19 and EPA-HQ-OAR-2002-0058-3502-A1, excerpt 23 regarding establishing work practice standards for malfunctions.

Commenter Name: Susan J. Miller

Commenter Affiliation: Brick Industry Association (BIA)

Document Control Number: EPA-HQ-OAR-2002-0058-3530-A1

Comment Excerpt Number: 4

Comment: EPA’s proposal to provide an “affirmative defense” for periods of malfunctions is without merit. BIA is part of the “SSM Coalition” who recently submitted comments on EPA’s proposed “Risk and Technology Review” rule for Mineral Wool and Wool Fiberglass manufacturing. These comments explain in detail that: (1) EPA must take malfunctions into account when setting §112 emissions standards; (2) the proposed affirmative defense is not a permissible substitute for setting emissions standards for periods of malfunction; and (3) the proposed affirmative defense is unreasonable and impracticable.² We incorporate these comments of the SSM Coalition by reference. For these reasons, EPA should set aside the proposed affirmative defense for periods of malfunction and, instead, set a work practice standard for such periods.

[Footnote]

(2) *See* Letter to EPA Docket Center from the American Chemistry Council, *et al.*, Comments on Proposed National Emission Standards for Hazardous Air Pollutant Emissions: Mineral Wool Production and Wool Fiberglass Manufacturing (January 24, 2012).

Response: See the responses to comments EPA-HQ-OAR-2002-0058-3500-A1, excerpt 19 and EPA-HQ-OAR-2002-0058-3502-A1, excerpt 23 regarding establishing work practice standards for malfunctions.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 50

Comment: Unlike startup and shutdown periods, EPA has determined that malfunctions should not have work practice standards and has instead provided for an affirmative defense. 76 Fed. Reg. 80,629.

Given that malfunctions are essentially the same as periods of startup and shutdown, work practice standards should also apply. As CIBO points out in its Petition, EPA recognizes in both the Boiler MACT and Area Source rule, "that it is not feasible to require stack testing – in particular, to complete the multiple required test runs – during periods of startup and shutdown due to physical limitations and the short duration of startup and shutdown periods. Operating in startup and shutdown mode for sufficient time to conduct the required test runs could result in higher emissions than would otherwise occur." 76 Fed. Reg. 15577, 15642. It is irrational to view malfunctions any different than startup/shutdown periods. As such, EPA should establish work practice standards for malfunctions. The rule is unreasonable as it is and subjects sources to the risk of noncompliance especially given the fact that malfunctions are unavoidable and unpredictable.

In doing so, EPA has inappropriately placed the burden on the source to prove that excess emissions were caused by a malfunction. As CIBO asserted in earlier comments, malfunctions are in all material respects the same as startup and shutdown and therefore clearly meet the CAA definition for when work practice standards are appropriate. CAA §112(h). EPA should establish a work practice standard that requires pre-determined malfunction plans with practices and procedures for potential malfunctions; require reporting of any malfunctions; address any malfunctions not contemplated and add to the plan and address as appropriate.

Response: See the responses to comments EPA-HQ-OAR-2002-0058-3500-A1, excerpt 19 and EPA-HQ-OAR-2002-0058-3502-A1, excerpt 23 regarding establishing work practice standards for malfunctions.

Commenter Name: John M. Cullen

Commenter Affiliation: Masco Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3661-A2

Comment Excerpt Number: 8

Comment: Masco submits that EPA should impose work practice standards for periods of malfunction rather than the proposed affirmative defense, which appears inadequate and impracticable.

Response: See the responses to comments EPA-HQ-OAR-2002-0058-3500-A1, excerpt 19 and EPA-HQ-OAR-2002-0058-3502-A1, excerpt 23 regarding establishing work practice standards for malfunctions.

Commenter Name: Annabeth Reitter

Commenter Affiliation: NewPage Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3662-A2

Comment Excerpt Number: 11

Comment: Unlike startup and shutdown periods, EPA has determined that malfunctions should not have work practice standards and has instead provided for an affirmative defense. (see 76 Fed. Reg. 80629).

In the preamble to the March 2011 final Boiler MACT rule, EPA recognizes the need to exclude malfunction events when setting emission standards. As such, EPA should re-establish work practice standards for malfunctions in place of the affirmative defense approach included in the reconsideration proposal.

With the use of affirmative defense, EPA has placed unreasonable burdens on the source to prove that excess emissions were caused by a malfunction. The affirmative defense approach is unreasonable as it potentially subjects sources to the risk of noncompliance, especially given the fact that malfunctions are unavoidable and unpredictable. Overall, these provisions impose vague obligations on malfunctioning sources which will lead to inconsistent interpretations in different jurisdictions, and lack precision that is fundamental to an adequate defense in an enforcement proceeding. This could lead to the EPA or a court imposing extreme MACT regulations on sources during malfunctions.

EPA identifies many reasons in the preamble supporting its establishment of work practice standards during periods of startup and shutdown. These same bases support the establishment of work place standards being applicable to malfunctions. Malfunctions meet the CAA definition (CAA §112(h)) for when work practice standards are appropriate. Instead of using the affirmative defense approach, EPA should establish a work practice standard that requires pre-determined malfunction plans with practices and procedures for addressing potential malfunctions that will minimize emissions in a manner consistent with good safety practices and good air pollution control practices; require reporting of any malfunctions; and include provisions for modifying the plan to incorporate any malfunctions not contemplated.

Response: See the responses to comments EPA-HQ-OAR-2002-0058-3500-A1, excerpt 19 and EPA-HQ-OAR-2002-0058-3502-A1, excerpt 23 regarding establishing work practice standards for malfunctions.

Commenter Name: Janice E. Nolen

Commenter Affiliation: American Lung Association

Document Control Number: EPA-HQ-OAR-2002-0058-3679-A2

Comment Excerpt Number: 13

Comment: Affirmative defense for malfunctions. EPA should review the exposure estimates to recognize that significant air emissions are likely to result from malfunctioning equipment as well. Although some malfunctions may be unpredictable and sudden, EPA must account for the harmful emissions that occur during malfunctions when determining whether or not a facility is in compliance with emissions standards. EPA needs to acknowledge that malfunctions are likely events which must be factored into the exposure estimates. EPA's language implies that these are rare events, but such is not the case, as recent reports have shown (EPA, 2011d). The historical industry evidence should provide more than adequate information on likely malfunctions and exposures.

Unfortunately, the proposed "affirmative defense" option creates a loophole that will not likely reduce the risk of malfunctions, providing facilities with a way to avoid penalties that could provide incentives to reduce malfunctions. The EPA needs to close this loophole as standards need to limit emissions during all phases of operation, including when equipment fails to work properly. Assessing compliance with emissions standards based on the "good faith efforts" of boiler and incinerator operators to minimize emissions during malfunctions are not a sufficient safeguard against harmful air pollution.

Response: See the responses to comments EPA-HQ-OAR-2002-0058-3500-A1, excerpt 19 and EPA-HQ-OAR-2002-0058-3502-A1, excerpt 23 regarding establishing work practice standards for malfunctions.

Commenter Name: Kerry Kelly

Commenter Affiliation: Waste Management (WM)

Document Control Number: EPA-HQ-OAR-2002-0058-3681-A2

Comment Excerpt Number: 28

Comment: EPA admits it does not have emissions data for startup and shutdown periods sufficient to establish numeric emission limits, and due to this dearth of data has sensibly adopted a work practice standard for these periods. Malfunction periods are no different and should be treated similarly. Since EPA also lacks emissions data for malfunction periods, and would find it difficult to obtain sufficient emission data for all the varying types of malfunction-related events, EPA should adopt work practice standards for malfunction periods.

Response: See the responses to comments EPA-HQ-OAR-2002-0058-3500-A1, excerpt 19 and EPA-HQ-OAR-2002-0058-3502-A1, excerpt 23 regarding establishing work practice standards for malfunctions.

Commenter Name: Russell A. Wozniak

Commenter Affiliation: The Dow Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3449-A1

Comment Excerpt Number: 27

Comment: In 40 CFR 63.7535(a), EPA requires the owner/operator to complete monitoring system repairs in response to monitoring system malfunctions or out-of-control periods and to return the monitoring system to operation as expeditiously as practicable. Dow supports this work practice requirement for monitoring system malfunctions. However, the proposed rule text in 40 CFR 63.7501 regarding "malfunctions" should clearly exclude monitoring system malfunctions if no excess emissions occur as a result of the monitoring system malfunction. EPA's proposed 63.7501 provides that the owner/operator may assert an affirmative defense to a claim for civil penalties for exceeding such standards that are caused by a malfunction as the term is defined in 40 CFR 63.2:

Malfunction – means any sudden, infrequent, and not reasonably preventable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner which causes, or has the potential to cause, the emission limitations in an applicable standard to be exceeded. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

If the owner/operator can show that a monitoring system malfunction does not result in an exceedance of an emission limitation, then the final rule should clarify that the owner/operator does not need to assert an affirmative defense for such monitoring system malfunction.

Response: The affirmative defense criteria are not requirements that a source must meet. In an action to enforce a violation of a standard caused by a malfunction, a source can choose to assert an affirmative defense. The affirmative defense is not relevant to malfunctions that do not result in violations of emission standards.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 93

Comment: EPA asserts that "it is reasonable to interpret section 112(d) as not requiring EPA to account for malfunctions in setting emissions standards." 76 Fed. Reg.15613. EPA offers little support for that assertion, however, other than stating its own, often counterintuitive, conclusions. For example, EPA says it "has determined that malfunctions should not be viewed as a distinct operating mode and, therefore, any emissions that occur at such times do not need to be factored into development of CAA section 112(d) standards, which, once promulgated, apply at all times." *Id.* EPA provides no explanation for why it "believes" that malfunctions are not a distinct operating mode. Moreover, EPA offers no explanation of its contradictory position that, even though it believes malfunctions are not a distinct operating mode, emissions during malfunctions should not be used to characterize the source's operating mode. On its face, asserting that malfunctions are part of normal operations, but then excluding emissions during malfunctions when determining emission limitations for normal operations, makes no sense.³¹

EPA's statement that "nothing in section 112(d) or in case law requires that EPA anticipate and account for the innumerable types of potential malfunction events in setting emission standards," *id.*, has it backwards. There is nothing in CAA § 112 that allows EPA to ignore malfunctions and set MACT standards—which are supposed to represent the performance actually achieved by the

MACT “floor” sources—based on a level of emissions that even these best-performing sources only achieve part of the time. [Footnote 31: The *Weyerhaeuser Co. v. Costle* decision EPA cites in the March 21, 2011 preamble, 590 F. 2d 1011 (D.C. Cir. 1978), does not support EPA’s position. See 76 Fed. Reg. at 15613. In that case, the court was discussing a “technology forcing” standard, rather than one, like MACT, that is to be based on what is already being “achieved” or has been demonstrated to be achievable. Also, the SSM events that EPA acknowledges are expected to occur at sources subject to the MACT standards or boilers and process heaters are a far cry from the “uncontrollable acts of third parties, ‘ such as strikes, sabotage, operator intoxication, or insanity” that the Court was considering in the passage quoted by EPA, see *id.* Industry is not requesting that the emission standards provide relief from numerical emission limitations during those unusual types of events. Perhaps most importantly, the *Weyerhaeuser* decision came long before *NRDC v. EPA*, 859 F.2d 156 (D.C. Cir. 1988) which, as noted above, affirmed the need for an upset provision to address circumstances where compliance with effluent limitations is impossible through no fault of the permittee.]

Response: See the response to comment EPA-HQ-OAR-2002-0058-3667-A2, excerpt 22 regarding developing emission limits and malfunctions.

Commenter Name: Jennifer Youngblood

Commenter Affiliation: National Tribal Air Association

Document Control Number: EPA-HQ-OAR-2002-0058-3667-A2

Comment Excerpt Number: 23

Comment: EPA fails to explain how the Mossville criterion [*Mossville Environmental Action Now v. EPA*, 370 F.3d 1232, 1242 (D.C. Cir. 2004)] is met for a reasonable standard of factoring in variability under all operating conditions, when no malfunction emission data is included in the database used to make the variability adjustment. Nor does EPA explain how the *Weyerhaeuser* decision (that they do not have to consider every type of malfunction) allows EPA to ignore all types of malfunctions in establishing emission limits. EPA fails to explain how it concluded under section 112(d) that it is reasonable to ignore all malfunctions in setting emission limits. Even best performing sources have malfunctions and section 112(d)(3) requires EPA to understand the “emission control that is achieved in practice” by such sources. Finally, EPA has not shown how it concluded it did not have to treat emission limits that do not consider malfunctions as “beyond the floor” limits, since the floor must include malfunctions, since such a standard is not achievable by the best performing sources when they malfunction.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3667-A2, excerpt 22 regarding developing emission limits and malfunctions.

Commenter Name: Jennifer Youngblood

Commenter Affiliation: National Tribal Air Association

Document Control Number: EPA-HQ-OAR-2002-0058-3667-A2

Comment Excerpt Number: 25

Comment: If it is possible to gather sufficient representative data reflecting emissions during malfunctions, then EPA is obligated to consider these data in its calculations of numerical emission limits for steady-state operating conditions (since EPA asserts malfunctions are not a

separate operating mode). If it is not possible to gather sufficient representative data reflecting emissions during malfunctions then EPA is obligated to treat malfunctions as a separate operating mode. We note that at least for the proposed CO emission limits for most source categories, EPA has adequate continuous monitoring data to develop alternative standards and thus may have data that includes malfunctions and thus may, as we discuss in Comment II.4.A, actually may be able to establish an emission limitation for CO that does consider malfunctions (i.e., establish the proposed alternative standard as the primary standard for CO for those subcategories.)

Response: See the response to comment EPA-HQ-OAR-2002-0058-3667-A2, excerpt 22 regarding developing emission limits and malfunctions.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 75

Comment: The proposed Affirmative Defense is not a substitute for addressing malfunction events in the emission limitations themselves.

EPA acknowledges that the sources that will be subject to the proposal sometimes will be unable to comply with the standards because of malfunctions, even if their equipment is properly designed and maintained, through no fault of the source.⁴³ Rather than promulgate a standard of performance that eliminates that situation, so that the regulated emission sources will be subject to differentiated requirements including during malfunction events, EPA offers instead an “affirmative defense.” As discussed in our next comment, the proposed affirmative defense shifts the burden to the source to prove that a myriad number of criteria are met and actions were taken by the source (which criteria bear no direct relation to the statutory factors for standards of performance in the CAA or delineated in the definition of malfunction in §63.2), in order to avoid “civil penalties.” Inclusion of the affirmative defense does not cure EPA’s failure to set emission standards that are achievable during malfunctions. The proposed standards, incorporating the affirmative defense, still do not represent emission limitations that have been achieved in practice by the best performers.

[Footnote 43:76 Fed. Reg. 15613 (March 21, 2011)]

Response: See the response to comment EPA-HQ-OAR-2002-0058-3667-A2, excerpt 22 regarding developing emission limits and malfunctions.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 88

Comment: *EPA Failed to Consider Malfunctions in Establishing MACT Numeric Emission Standards.*

Under CAA § 112(d)(2), MACT emission standards must be "achievable." Moreover, when EPA establishes emission standards for existing sources based on the "best performing 12% of units in the category" (the "MACT floor"), those emission standards must on average be "achieved" by the best performers. *See*, § 112(d)(3). If EPA is going to require sources to meet a numeric standard at "all times" then the Agency must demonstrate that the standard accommodates the variability in emissions experienced, i.e., "achieved", by best performing sources "at all times", which would have to take into account, among other things, a potential malfunction. Based on our review of documents in the docket for this rulemaking it appears that EPA did not consider any data identifying the level of HAP emissions that may result when a best performing source experiences a malfunction. EPA therefore has failed to show that HAP emission numeric limits that apply at all times reflect the reductions that are "achieved" by best performing sources during a malfunction.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3667-A2, excerpt 22 regarding developing emission limits and malfunctions. See the responses to comments EPA-HQ-OAR-2002-0058-3500-A1, excerpt 19 and EPA-HQ-OAR-2002-0058-3502-A1, excerpt 23 regarding establishing work practice standards for malfunctions.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 91

Comment: *EPA's Inclusion of an Affirmative Defense Is Not a Substitute for Establishing a § 112-Compliant Standard for Malfunction Events.*

ACC believes that EPA should either revise the numeric emission limitations in the rule so that they consider and reflect the variability of emissions resulting from malfunction events, or use its statutory authority to establish a §112 work practice or management standard applicable during a malfunction event. There is no language in § 112 that authorizes EPA to offer an owner/operator an "affirmative defense" to civil penalties to cure the fact that it has finalized numeric emission standards that do not represent the emission levels actually "achieved by the best performing sources "at all times".

Response: See the response to comment EPA-HQ-OAR-2002-0058-3667-A2, excerpt 22 regarding developing emission limits and malfunctions. See the responses to comments EPA-HQ-OAR-2002-0058-3500-A1, excerpt 19 and EPA-HQ-OAR-2002-0058-3502-A1, excerpt 23 regarding establishing work practice standards for malfunctions.

Commenter Name: Jennifer Youngblood

Commenter Affiliation: National Tribal Air Association

Document Control Number: EPA-HQ-OAR-2002-0058-3667-A2

Comment Excerpt Number: 24

Comment: Rather than supporting EPA's decision to ignore the fact that malfunction events can lead to higher emissions even at well-operated facilities with the best control equipment, the difficulty in measuring emissions during malfunctions should lead EPA to its conclude that

malfunctions are not normal operations and that their authority under CAA section 112(h) to prescribe alternative design, equipment, work practice, or operational standards where it is not feasible to set or enforce a numerical emission limit should be employed. EPA cannot rationally defend its position that malfunctions are normal operations but then ignore those operations in defining the emission limits that are "achieved in practice" by the best performing sources.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3667-A2, excerpt 22 regarding developing emission limits and malfunctions. See the responses to comments EPA-HQ-OAR-2002-0058-3500-A1, excerpt 19 and EPA-HQ-OAR-2002-0058-3502-A1, excerpt 23 regarding establishing work practice standards for malfunctions.

Commenter Name: Melvin E. Keener

Commenter Affiliation: Coalition for Responsible Waste Incineration (CRWI)

Document Control Number: EPA-HQ-OAR-2002-0058-3454-A1

Comment Excerpt Number: 12

Comment: CRWI notes that EPA does not allow facilities to assert an affirmative defense for the exceedance of an emission limit during malfunctions if EPA is seeking to enforce that emission limit through injunctive relief. Apparently the Agency takes that position based on a memorandum, State Implementation Plans: Policy Regarding Excessive Emissions During Malfunctions, Startup, and Shutdown at 2 (Sept. 20, 1999). (SIP SSM Memo). CRWI asserts that this policy is wrong. The type of legal action or relief should have no bearing on the availability of this defense. A malfunction "is a sudden, infrequent, not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner." 40 CFR § 60.2. It is not affected by the type of enforcement action EPA may eventually bring. Indeed, because a malfunction is not reasonably preventable, enforcement actions, regardless of type, have no deterrent effect on them. Therefore, the type of legal action EPA uses to enforce a violation of its emission limits is simply irrelevant to whether the violation should be excused because of circumstances beyond the facilities control.

Response: In exercising its authority under section 112 to establish emission standards (at a level that meets the stringency requirements of section 112), the EPA necessarily defines conduct that constitutes a violation. The EPA's view is that the affirmative defense can be viewed as defining two categories of violation. If there is a violation of the emission standard and the source demonstrates that all the elements of the affirmative defense are met, only injunctive relief is available. All other violations of the emission standard are subject to injunctive relief and penalties. The CAA does not require that all violations be treated equally. Further, a citizen suit claim under section 304 allows citizens to commence a civil action against any person alleged to be in violation of "an emission standard or limitation under this chapter." The CAA, however, allows the EPA to establish such "enforceable emission limitations." Thus, the citizen suit provision clearly contemplates enforcement of the standards that are defined by the EPA. As a result, where the EPA defines its emissions limitations and enforcement measures to allow a source the opportunity to prove its entitlement to a lesser degree of violation (not subject to penalties) in narrow, specified circumstances, as the EPA did here, penalties are not "appropriate" under section 304.

The EPA's view is that an affirmative defense to civil penalties for exceedances of applicable emission standards during periods of malfunction appropriately balances competing concerns. On the one hand, citizen enforcers are concerned about additional complications in their enforcement actions. On the other hand, industrial sources are concerned about being penalized for violations caused by malfunctions that could not have prevented and were otherwise appropriately handled (as reflected in the affirmative defense criteria). The EPA has utilized its Section 301(a)(1) authority to issue regulations necessary to carry out the Act in a manner that appropriately balances these competing concerns.

Commenter Name: Lee Zeugin and Lauren Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1

Comment Excerpt Number: 16

Comment: EPA solicits comment on malfunctions and the affirmative defense provision included in the 2011 final rule. In that rule, EPA addresses periods of malfunction by providing an "affirmative defense" to a claim of civil penalties. 40 C.F.R. § 63.7501. To establish the defense an owner/operator must (1) provide notice by telephone or facsimile no later than two business days after the "initial occurrence" of the malfunction, and (2) submit a written report within 45 days proving certain facts by a "preponderance of evidence." *Id.* EPA's "affirmative defense" approach is not the exclusive, or even the best, option available for treatment of malfunctions under CAA § 112. Because the final rule treats exceedances caused by malfunctions as "violations," it does not prevent owners and operators from being penalized for events that cannot be reasonably prevented, even if civil penalties do not apply. It also raises a number of practical issues.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3454-A1, excerpt 12 regarding malfunctions being preventable.

Commenter Name: Kerry Kelly

Commenter Affiliation: Waste Management (WM)

Document Control Number: EPA-HQ-OAR-2002-0058-3681-A2

Comment Excerpt Number: 29

Comment: Malfunction work practice standards could include limitations on the duration to ensure quick and effective corrective action is taken, and if the malfunction cannot be quickly resolved the unit would be shut down for repair. Facilities should still be required to submit a notification of a malfunction excess emission event with the underlying root cause analysis. If EPA or the administering agency decides the excess emission event was not a malfunction, it would then be reported as a deviation of the limit and enforcement action, including imposition of penalties, would still apply consistent with the deviation definition in 63.7575. EPA could also choose to take enforcement action should a facility report "excessive" malfunction events.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3454-A1, excerpt 12 regarding malfunctions being preventable.

Commenter Name: Allison Watkins, Baker Botts
Commenter Affiliation: Class of '85 Regulatory Response Group
Document Control Number: EPA-HQ-OAR-2002-0058-3608-A1
Comment Excerpt Number: 2

Comment: The Class of '85 supports EPA's addition of an affirmative defense to civil penalties for exceedences of emissions limits that are caused by malfunctions. The Class of '85 agrees with EPA that even equipment that is properly designed and maintained can sometimes fail. Facilities that exceed emissions standards during such unforeseen events should not be penalized.

Response: The EPA thanks the commenter for their support.

Commenter Name: Randal G. Oswald
Commenter Affiliation: Integrys Energy Group
Document Control Number: EPA-HQ-OAR-2002-0058-3659-A2
Comment Excerpt Number: 2

Comment: Integrys supports EPA's addition of an affirmative defense to civil penalties for exceedences of emissions limits that are caused by malfunctions. We agree with EPA that even equipment that is properly designed and maintained can sometimes fail. Facilities that exceed emissions standards during such unforeseen events should not be penalized.

Response: The EPA thanks the commenter for their support.

Commenter Name: James Pew
Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity
Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1
Comment Excerpt Number: 58

Comment: Assuming *arguendo* that EPA had authority to promulgate any type of affirmative defense to penalties for malfunctions, EPA should also promulgate the following provision: A specific amount of compensatory damages should apply to each reported malfunction. These funds should be dedicated to enforcement, inspections, and monitoring in the local community around the specific facility, to create greater assurance that malfunctions will not happen again.

Response: The EPA is not adopting commenters' suggestion with respect to compensatory damages or limits on the frequency of use of the affirmative defense. It is not clear that EPA has authority to require the automatic imposition of compensatory damages and even if such authority exists, the EPA does not think automatic imposition of damages is appropriate, as it would unduly complicate the enforcement process. Ensuring that malfunctions do not recur can be handled through imposition of appropriate injunctive relief.

Commenter Name: James Pew
Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 59

Comment: Assuming *arguendo* that EPA had authority to promulgate any type of affirmative defense to penalties for malfunctions, EPA should also promulgate the following provision: EPA should modify the regulations so that the affirmative defense cannot be used by a specific facility or company more than once within a set period of time, such as 10 years. The affirmative defense should become automatically unavailable to a facility that has previously had a malfunction within the last 10 years, to ensure that this defense does not swallow the value of the standards.

Response: It is EPA's view is that it would not be appropriate to limit a source's ability to take advantage of the affirmative defense to one time over a specified period of time such as ten years given that the affirmative defense is only available when the source could not have prevented the excess emissions. With respect to commenters' suggested reporting requirements, the reporting requirements in the rules promulgated today already require malfunction reporting and the affirmative defense provisions require that parties choosing to assert the affirmative defense meet additional malfunction reporting requirements. Any such reports submitted to the EPA are publicly-available pursuant to CAA section 114.

Commenter Name: LESLIE SUE RITTS

Commenter Affiliation: National Environmental Development Association's Clean Air Project (NEDA/CAP)

Document Control Number: EPA-HQ-OAR-2002-0058-3529-A1

Comment Excerpt Number: 12

Comment: Sub par. (2) of the affirmative defense requires that an owner/operator establish by a preponderance of the evidence that repairs were made as expeditiously as possible when the applicable emission limitations were being exceeded and that "*Off-shift and overtime labor were used, to the extent practicable to make these repairs...*". The requirement for off-shift and overtime labor should be deleted from the regulation. Bringing in off-shift or overtime labor is not always wise or necessary to demonstrate that repairs have been made as expeditiously as practicable. Expertise, not numbers of unskilled employees or tired employees, is paramount to resolving most safety issues created by malfunctioning equipment. If retained in the final rule, it should be used as an example of how an operator *may* demonstrate that a problem was resolved as expeditiously as practicable.

Response: We have also re-evaluated the language concerning the use of off-shift and overtime labor to the extent practicable and believe that the language is not necessary. Thus, we have deleted that phrase from section 63.7501(a)(2).

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 81

Comment: Proposed §63.7501(a) follows.

§63.7501(a) To establish the affirmative defense in any action to enforce such a limit, you must timely meet the notification requirements in paragraph (b) of this section, and must prove by a preponderance of evidence that:

We comment separately below (Comment II.8.D) on the wasteful and unreasonable notification requirements proposed in §63.7501(b).

Proposed §63.7501(a)(1):

The excess emissions:

(i) Were caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner, and

(ii) Could not have been prevented through careful planning, proper design or better operation and maintenance practices; and

(iii) Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and

(iv) Were not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

§63.7501(a)(1)(i) reflects the key criteria from the definition of malfunction in §63.248 . However, the (ii) through (iv) paragraphs are unreasonable, arbitrary, and capricious restatements and expansions of the last sentence of the §63.2 malfunction definition and should be deleted and replaced with the language from the definition. EPA has not explained in the rulemaking record their legal or logical basis for expanding and changing the malfunction criteria and, in particular, have not proposed changing the definition, either through proposing a revised definition in this rulemaking or proposing to amend §63.2. As explained below, these new malfunction criteria would not allow any event to be a malfunction, since the criteria, if interpreted literally, cannot be met. The phrases used in these paragraphs are subject to a wide range of interpretations, and on their face do not recognize any need for reasonableness or cost-effectiveness. The language used presumes guilt and imposes an unclear and apparently impossible level of proof for a source to defend itself. The proposed wording doesn't even track the language of the definition of "malfunction" by including an analysis of whether an event was due to poor maintenance or careless operation. Instead, the proposal focuses on whether "proper design" or "better operation and maintenance practices" could have prevented a malfunction. There are no objective criteria that can be used to determine what "could" have been and there is probably no situation where, in hindsight and without considering cost or likelihood, that an event could not have been prevented.

[Footnote 48: *Malfunction* means any sudden, infrequent, and not reasonably preventable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner which causes, or has the potential to cause, the emission limitations in

an applicable standard to be exceeded. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.]

Response: EPA disagrees with comments that criticize the affirmative defense criteria as being overly vague or unduly restrictive and complex. The EPA believes that courts are well equipped and often do evaluate and apply the type of criteria set forth in the affirmative defense. The EPA recognizes that some of the criteria for establishing an affirmative defense may be redundant of the general duty, but does not agree that such redundancy is a problem. The EPA notes that the affirmative defense criteria and the general duty to minimize emissions do not operate in the same manner. The general duty is applicable to a source at all times. The affirmative defense criteria are only relevant if a source chooses to take advantage of the affirmative defense. The EPA's view is that use of consistent terms in establishing affirmative defense regulations and policies across various CAA programs will promote consistent implementation of those rules and policies.

The EPA revised certain criteria of the affirmative defense provisions that may ease the burden for owners and operators. The EPA is eliminating both the immediate notification and 45-day malfunction report requirement. Instead, the final rule allows owners or operators seeking to assert an affirmative defense to demonstrate, with all necessary supporting documentation (as was required under the proposed 45-day report), that it has met the affirmative defense criteria by including the report in the first periodic compliance, deviation report or excess emission report otherwise required after the initial occurrence of the violation of the relevant standard (which may be the end of any applicable averaging period). If such compliance, deviation report or excess emission report is due less than 45 days after the initial occurrence of the violation, the affirmative defense report may be included in the second compliance, deviation report or excess emission report due after the initial occurrence of the violation of the relevant standard. This change provides sources with sufficient time to demonstrate that they have met the required affirmative defense criteria. With regard to severe property damage, the EPA believes that a bypass of control equipment or a process, which results in a violation, should be an exception and not undertaken lightly, and has maintained the word "severe" in this criteria.

Commenter Name: Russell A. Wozniak

Commenter Affiliation: The Dow Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3449-A1

Comment Excerpt Number: 23

Comment: 40 CFR §63.7501 (a) (2) Repairs were made as expeditiously as practical possible when the applicable emission limitations were being exceeded. Off shift and overtime labor were used, to the extent practical to make these repairs; and

Dow Comment: Responding to malfunctions is many times a case-by-case situation depending on the specifics of the malfunction and equipment to be repaired, and the language regarding off-shift and overtime labor is unnecessary and confusing. The use of overtime or off-shift labor is only one consideration in how to address a malfunction event. If EPA wants to point out that the use of overtime or off-shift labor must be used, then this language is best included in the preamble rather than the rule itself.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3529-A1, excerpt 12 regarding use of off-shift and overtime labor during a malfunction.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 100

Comment: Turning to the individual requirements in § 63.7501(a)(1) through (9) that a facility must meet to be allowed to raise an affirmative defense, a number of these requirements are not relevant to whether a "malfunction", as defined in 40 CFR 63.2 occurred.

Malfunction means any sudden, infrequent, and not reasonably preventable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner which causes, or has the potential to cause, the emission limitations in an applicable standard to be exceeded. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Most of the conditions for establishing an affirmative defense in § 63.7501 may be relevant to determining whether the facility undertook appropriate and necessary measures to mitigate any excess emissions resulting from the specific malfunction, but do not in any way inform a determination of whether a piece of equipment has met the definition of a malfunction. For example, § 63.7501(a)(2) requires that "off-shift and overtime labor, to the extent practicable" were used to make the repairs needed. ACC fails to understand how this requirement relevant to determining whether a piece of equipment has "malfunctioned". See also (a)(3), (a)(5), (a)(6), (a)(7), (a)(8) and (a)(9).

Response: See the response to comment EPA-HQ-OAR-2002-0058-3529-A1, excerpt 12 regarding use of off-shift and overtime labor during a malfunction.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 51

Comment: Alternatively, if EPA rejects such work practice standards and, instead, includes an affirmative defense for malfunctions, the terms of the defense need to be changed. First, a source should not have to prove it meets every criterion to successfully claim the affirmative defense. Rather, the different criteria should be factored in evaluating whether the excess emissions should be excused.

The proposed criteria in the Reconsideration Rule for establishing an affirmative defense, which did not change from the Final Rule, are poorly defined and do not reflect on whether a malfunction actually occurred. For example, the requirement that sources rely on overtime workers to address the malfunction, 76 Fed. Reg. 80,629, objectively proves nothing. The personnel onsite at the time of the malfunction event may not be the personnel with the expertise to resolve the malfunction, yet if they do not remain onsite as overtime personnel, under EPA's

structure, that source fails to meet one of the indicia of a malfunction. Moreover, the affirmative defense criteria in some cases impose draconian obligations on malfunctioning sources without any regard for their cost-effectiveness. For example, the source must show "[r]epairs were made as expeditiously as possible . . . excess emissions (including any bypass) were minimized to the maximum extent practicable . . . [a]ll possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment and human health." 76 Fed. Reg. 80,629 (emphasis added). This could lead to the EPA or a court imposing extreme MACT regulations on sources during malfunctions. Overall, the provisions impose vague obligations on malfunctioning sources which will lead to inconsistent interpretations in different jurisdictions, and lack precision that is fundamental to an adequate defense in an enforcement proceeding.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3529-A1, excerpt 12 regarding use of off-shift and overtime labor during a malfunction. See the response to comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 81 regarding affirmative defense provisions.

Commenter Name: Russell A. Wozniak
Commenter Affiliation: The Dow Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3449-A1
Comment Excerpt Number: 20

Comment: EPA should modify Section 63.7501 of the rule that cover malfunctions and should significantly revise the affirmative defense provisions.

Dow recognizes that the proposed regulatory text is not unique to this MACT standard; EPA is inserting similar requirements in other MACT rules. However, the "affirmative defense" as currently written imposes such onerous requirements that the defense will be of extremely limited use as a practical matter. EPA should programmatically (including in this rule) revise the affirmative defense so that it is meaningful for larger events that may occur.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 81 regarding affirmative defense provisions.

Commenter Name: Bruce W. Ramme
Commenter Affiliation: Wisconsin Electric Power Company (WE Energies)
Document Control Number: EPA-HQ-OAR-2002-0058-3452-A1
Comment Excerpt Number: 7

Comment: We Energies understands that the intent of the affirmative defense provision is to provide owners and operators with protections in the event of an unforeseeable malfunction. We Energies supports the creation of an exemption from the emissions and operating limitations contained in the IB-MACT rule for malfunctions. The affirmative defense provisions proposed by EPA, however, would place unnecessary reporting burdens on sources, and could lead to unwarranted litigation and general confusion regarding the sufficiency of the factual information required to be maintained in order to qualify for the exemption.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 81 regarding affirmative defense provisions.

Commenter Name: Bruce W. Ramme
Commenter Affiliation: Wisconsin Electric Power Company (WE Energies)
Document Control Number: EPA-HQ-OAR-2002-0058-3452-A1
Comment Excerpt Number: 10

Comment: The various items that an owner or operator seeking to use the affirmative defense must “prove by preponderance of the evidence” are in many instances subjective, and EPA has not yet provided sufficient guidance regarding how it will interpret these requirements. We request that EPA provide guidance containing concrete examples that illustrate the actions that must be undertaken to address a malfunction in order to qualify for the affirmative defense. This would provide more clarity and eliminate unnecessary speculation.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 81 regarding affirmative defense provisions.

Commenter Name: Melvin E. Keener
Commenter Affiliation: Coalition for Responsible Waste Incineration (CRWI)
Document Control Number: EPA-HQ-OAR-2002-0058-3454-A1
Comment Excerpt Number: 14

Comment: CRWI suggests that EPA consider making the following modifications to the regulatory language in § 63.7501 to address the concerns mentioned above and to make an affirmative defense a more useful tool (using ~~strikeout~~ to show text deleted and underline to show text added).

§ 63.7501 How can I assert an affirmative defense if I exceed an emission limitations during a malfunction?

In response to an action to enforce the emission limitations and operating limits set forth in § 63.7500 you may assert an affirmative defense to a claim for civil penalties for exceeding such standards that are caused by malfunction, as defined at § 63.2. Appropriate penalties may be assessed, however, if you fail to meet your burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

(a) To establish the affirmative defense in any action to enforce such a limit, you must timely meet the notification requirements in paragraph (b) of this section, and must prove by a preponderance of evidence that:

(1) The excess emissions:

(i) Were caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner, and

(ii) Could not have been reasonably prevented through careful planning, proper design or better operation and maintenance practices; and

(iii) Did not stem from any activity or event that could have been reasonably foreseen and avoided, or planned for; and

(iv) Were not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

(2) Repairs were made as expeditiously as possible when the applicable emission limitations were being exceeded. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and

(3) The frequency, amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions; and

(4) If the excess emissions resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and

(5) ~~All possible~~ Reasonable steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment and human health; and

(6) ~~All e~~ Emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and

(7) ~~All of the a~~ Actions in response to the excess emissions were documented by ~~properly signed, contemporaneous operating logs~~; and

(8) ~~At all times, t~~ The facility was operated in a manner consistent with good practices for minimizing emissions; and

(9) A written ~~root cause analysis~~ report has been prepared, the purpose of which is to determine, ~~correct~~, and ~~eliminate~~ mitigate the primary causes of the malfunction and the excess emissions resulting from the malfunction event at issue. Facility personnel will determine the appropriate type of analysis

required (may include but not limited to root cause analysis, failure mode and effect, fault tree, etc.) to identify the cause of the malfunction. The analysis report shall also specify, using best monitoring methods and engineering judgment, the amount of excess emissions that were the result of the malfunction.

(b) *Notification.* The owner or operator of the facility experiencing an exceedance of its emission limitation(s) during a malfunction shall ~~notify the Administrator by telephone or facsimile (fax) transmission as soon as possible, but no later than 2 business days after the initial occurrence of the malfunction, if it wishes to avail itself of an affirmative defense to civil penalties for that malfunction. The owner or operator seeking to assert an affirmative defense shall also submit a~~ written report to the Administrator within 45 days of the initial occurrence of the exceedance of the standard in § 63.7500 to demonstrate, with all necessary supporting documentation, that it has met the requirements set forth in paragraph (a) of this section. The owner or operator may seek an extension of this deadline for up to 30 additional days by submitting a written request to the Administrator before the expiration of the 45-day period. Until a request for an extension has

been approved by the Administrator, the owner or operator is subject to the requirement to submit such report within 45 days of the initial occurrence of the exceedance.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 81 regarding affirmative defense provisions. See the responses to comments EPA-HQ-OAR-2002-0058-3510-A1, excerpt 106 and EPA-HQ-OAR-2002-0058-3677-A2, excerpt 90 regarding two-day malfunction notice and 45-day affirmative defense requirements. See the response to comment EPA-HQ-OAR-2002-0058-3454-A1, excerpt 10 regarding root cause analysis requirement.

Commenter Name: Timothy Serie

Commenter Affiliation: American Coatings Association (ACA)

Document Control Number: EPA-HQ-OAR-2002-0058-3502-A1

Comment Excerpt Number: 25

Comment: Finally, as a practical matter, the burden of proving all the requirements in the affirmative defense and notifying the Agency during a malfunction is excessively high; if EPA intends to maintain an affirmative defense provision, however, the Agency should clarify the language in this provision and make it reasonably possible to meet these criteria. The affirmative defense provisions from the reconsideration require the owner or operator of a boiler to prove by a preponderance of the evidence that the source meets a list of criteria. As the list is currently written, affected entities will struggle to meet many of the criteria in the affirmative defense, effectively limiting or eliminating any practical use of this defense. For example, the fifth criterion requires a facility to demonstrate that “[a]ll possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment and human health.” 76 Fed. Reg. 80629. This is a standardless condition and it would be extremely difficult, if not impossible, to demonstrate that all possible steps were taken to minimize the impact of a malfunction episode. A facility could always take one additional step to minimize the impact of a malfunction, and therefore, no facility could ever meet this criterion. If EPA does intend to finalize the affirmative defense, the Agency should clarify these provisions to ensure that the requirements are realistically attainable.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 81 regarding affirmative defense provisions.

Commenter Name: David A. Buff, Golder Associates Inc.

Commenter Affiliation: Florida Sugar Industry (FSI)

Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1

Comment Excerpt Number: 47

Comment: EPA’s requirements for establishing an affirmative defense are extremely onerous and unreasonable. Sugar mill boilers routinely experience significant fluctuations in operations that are beyond the reasonable control of the boiler and sugar mill operators. Fluctuations in the sugar mill that affect boiler operations include: processing of a biomass fuel that is harvested within the 24-hour period prior to processing; variations in sugarcane quality and type that occur throughout the crop season; weather conditions that affect cane quality (moisture and soil content) at varying times during the crop; starting and stopping of the sugar mill tandems;

sugarcane feed problems; mill equipment breakdown, etc. Factors associated with the boilers themselves can include: high and variable moisture content fuel; required high excess air rates; fuel feeder pluggage; wet bagasse piling up on the grates; load swings because all boilers are tied to a single steam header; etc.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 81 regarding affirmative defense provisions.

Commenter Name: David A. Buff, Golder Associates Inc.

Commenter Affiliation: Florida Sugar Industry (FSI)

Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1

Comment Excerpt Number: 48

Comment: One of the newest hybrid suspension grate boilers in the FSI (U.S. Sugar Boiler No. 8) has a CO CEMS and CO emission limit. The facility submits quarterly excess emission reports. Review of these reports reveals that up to 98 upset conditions were identified as malfunctions during any one quarterly period. A number of quarterly reports reported no malfunctions; however, upset conditions did occur, but ultimately none were excluded for purposes of demonstrating compliance with the CO limit for the boiler.

These fluctuations and other upset conditions would not qualify for an affirmative defense under the criteria set forth in the March 2011 Boiler MACT Rule. Even if they did qualify, the reporting and recordkeeping requirements established by EPA for proving an affirmative defense are too extensive and time-consuming. As a result, the FSI believes the EPA's affirmative defense is illusory and fails to provide a "safe harbor" from unwarranted enforcement cases.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 81 regarding affirmative defense provisions. See the responses to comments EPA-HQ-OAR-2002-0058-3510-A1, excerpt 106 and EPA-HQ-OAR-2002-0058-3677-A2, excerpt 90 regarding two-day malfunction notice and 45-day affirmative defense requirements.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 95

Comment: *EPA'S AFFIRMATIVE DEFENSE REQUIREMENTS ARE UNREASONABLE AND NOT CONSISTENT WITH § 112.*

The affirmative defense regulatory language in § 63.7501 opens with the words "*In response to an action to enforce* the emission limitations and operating limits set forth in..." and repeats this thought in paragraph (a) of the section: "To establish the affirmative defense

in any action to enforce such a limit..." (emphasis added). This opening language leaves a regulated party to believe that if any action is taken against that party to enforce an emission limit exceeded during a malfunction, the party may avail itself of an affirmative defense if it meets various criteria. However, this is not the way this would play out.

In § 63.7501(b) EPA establishes strict notification requirements that must be followed for the owner/operator to be able even to raise an affirmative defense if and when an enforcement action is brought. First, the owner/operator must notify EPA by phone or FAX as soon as possible, but no later than two business days after the "initial occurrence of the malfunction." Then, within 45 days of the "initial occurrence of the initial occurrence of the exceedance of the standard," the owner/operator must submit a written report accompanied by all necessary supporting documentation to show that it has met each and every requirement set forth in paragraph (a) of § 63.7501. Because of these short time frames, the reality is that EPA is requiring the facility to present its entire detailed defense in writing to EPA before EPA has even decided whether to take any enforcement action. To require a party to lay out its entire defense to a potential future enforcement action before that action may be taken is wholly inappropriate and unacceptable.

Response: See the responses to comments EPA-HQ-OAR-2002-0058-3510-A1, excerpt 106 and EPA-HQ-OAR-2002-0058-3677-A2, excerpt 90 regarding two-day malfunction notice and 45-day affirmative defense requirements. See the response to comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 87 regarding use of technology for recordkeeping and reporting.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 101

Comment: A number of the requirements are extremely subjective and fail to allow for consideration of reasonableness or cost-effectiveness. For example, § 63.7501(a)(1)(ii) requires the owner/operator to show that the malfunction could not have been prevented through "careful planning," "proper design" or "better operation and maintenance practices." This subjective requirement leaves open the possibility that an enforcement official could always find actions that "could" have been taken without any consideration of costs, resources or feasibility. Moreover, it fails to consider that an owner/operator may have chosen to redesign a process or equipment configuration, or make other adjustments to achieve the emission reductions necessary to comply with the standard. In so doing, the owner/operator would have evaluated various options to determine which one was the most cost-effective approach to achieve the emission standard, keeping in mind that cost-effectiveness would include long-term safe and proper operation of the equipment or process. If a malfunction were to occur, it could be difficult if not impossible for the owner/operator to prove that the malfunction "could not have been prevented" if cost and resources were never an issue.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 81 regarding affirmative defense provisions.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 103

Comment: Requirement (a)(4) would disallow the affirmative defense if a malfunction involved bypassing control equipment or a process, and the bypass was not taken "to prevent loss of life, severe personal injury, or severe property damage." This language is both unyielding and subjective. It is unyielding in that it fails to allow any consideration of the fact that bypassing the control equipment or the process may have been an appropriate exercise of good air pollution control practices. For example, a bypass can constitute the best air pollution control practice in response to an upset in order to prevent excess emissions, e.g., to avoid fouling of pollution control equipment media that in turn would result in reduced pollution control equipment efficiency or increased pollution control equipment downtime. Additionally, in some cases the air emissions from a venting event are lower than if the facility had an uncontrolled shutdown to avoid venting. An uncontrolled shutdown could also impact other media, e.g., a wastewater dump from scrubbers, solid waste, etc. And, a shutdown would necessitate additional startup emissions. Arguably, venting for a short period due to malfunction could result in less emissions than a non-orderly shutdown and subsequent restart. Yet, as worded, this requirement would discourage an owner/operator from taking the less-impactful option because it would mean that he could not avail himself of an affirmative defense for the malfunction.

This requirement is subjective in its use of the word —severe. Reasonable minds could disagree on what constitutes "severe" property damage, or "severe" personal injury. Lastly, this requirement is not supported by any explanation as to why "bypassing" control equipment or a process is absolutely unacceptable except when an owner/operator is faced with these dire consequences.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 81 regarding affirmative defense provisions.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 104

Comment: Requirement (a)(5) demands that a party prove that: "All possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment and human health." Again, the subjectivity of "all possible steps" is problematic in that it establishes a potentially unattainable standard with no clear direction as to how a party is to meet it.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 81 regarding affirmative defense provisions.

Commenter Name: Stephen E. Woock

Commenter Affiliation: Weyerhaeuser Company

Document Control Number: EPA-HQ-OAR-2002-0058-3523-A1

Comment Excerpt Number: 4

Comment: EPA proposes to treat malfunction events as if emission standards established based on normal process conditions and control equipment operations should apply. The "Affirmative Defense" policy EPA proposes to codify as potential protection when malfunctions lead to

emissions that exceed standards does not adequately address the issue. On its own it is overly complex in its documentation and reporting requirements that would be difficult, if not impossible, to meet during extreme or catastrophic malfunction events. The legally defensible and feasible approach is to set work practice standards as the NESHAP during malfunction events, as detailed in our trade group comments.

Response: See the responses to comments EPA-HQ-OAR-2002-0058-3500-A1, excerpt 19 and EPA-HQ-OAR-2002-0058-3502-A1, excerpt 23 regarding establishing work practice standards for malfunctions. See the response to comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 81 regarding affirmative defense provisions.

Commenter Name: LESLIE SUE RITTS

Commenter Affiliation: National Environmental Development Association's Clean Air Project (NEDA/CAP)

Document Control Number: EPA-HQ-OAR-2002-0058-3529-A1

Comment Excerpt Number: 13

Comment: Subpar. (4) of the affirmative defense that an owner operator establish by a preponderance of the evidence that if the excess emissions resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage. NEDA/CAP suggests that this is an unnecessary regulatory requirement and should be deleted from the final rule or that the word "potential" be inserted before the phrase "loss of life, personal injury or severe property damage." Bypassing emissions may be the only way to prevent "*potential*" risk to life or property in order to be eligible to an affirmative defense from injuries. In addition, when pollution equipment malfunctions, it may be unavoidable but not create a safety situation such as when there is a bypass of hot gases so that the pollution control equipment or even the process equipment can be taken apart to be repaired.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 81 regarding affirmative defense provisions.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 83

Comment: §63.7501(a)(1)(iv) requires a demonstration that a malfunction is not a result of a recurring pattern indicative of "inadequate design, operation, or maintenance." This is another impossible to demonstrate criterion since a regulator could easily take the position that if an event recurs it has to have been due to some inadequate design, operation, or maintenance. That is certainly the assumption behind the requirement for an RCA analysis.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 81 regarding affirmative defense provisions. See the response to comment EPA-HQ-OAR-2002-0058-3454-A1, excerpt 10 regarding root cause analysis requirement.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 84

Comment: Proposed §63.7501(a)(2):

Repairs were made as expeditiously as possible when the applicable emission limitations were being exceeded. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and

Proposed §63.7501(a)(2) imposes an unreasonable requirement and focuses on the wrong endpoint and should be deleted.

The phrase “as expeditiously as possible” is ambiguous and potentially impossible to meet. “Possible” is yet another subjective and ill-defined concept. In addition, acting as “expeditiously as possible” may cause safety or other problems as opposed to minimizing emissions to the maximum extent practicable, as the (a)(3) paragraph requires.

Furthermore, requiring the “repairs” to be done rapidly is not the correct focus because excess emissions may have ceased before repairs are complete or repairs may not be required. The correct focus should be on reducing the excess emissions as rapidly as practical, which is addressed in the proposed (a)(3) paragraph. Eliminating excess emissions may or may not involve repairs. For instance, the proper response to a particular event may require adjusting a control set point, bypassing a stuck control valve or other operator actions, shutting down the equipment or process, or routing the emissions to an alternate control. Requiring repairs, when no repair is needed is unreasonable and illogical.

The second sentence in proposed (a)(2), regarding the use of off-shift and overtime labor, is based on misperceptions that repairs are always needed and that using additional labor somehow indicates expediency. As mentioned previously, often the excess emissions have ceased prior to repair work occurring or do not require a repair to be made. Even where repairs are the critical path to minimizing emissions, work often may be managed adequately by shift personnel. In any given case, the enforcement authority may choose to question whether appropriate steps were taken to minimize emissions, so a firm requirement to bring in off-shift or overtime personnel when they are not needed serves no enforcement purpose. As proposed, this language requires use of off-shift and overtime labor if a source wants to use the affirmative defense, even if the excess emissions were stopped before such personnel could be called or no repair is needed or all needed personnel were already available onsite.

§63.7501(a)(2) should not be finalized and proposed §63.7501(a)(3) should remain as the basis for demonstrating an appropriate response to a malfunction, if these provisions remain in the final rule.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 81 regarding affirmative defense provisions. See the response to comment EPA-HQ-OAR-2002-0058-3529-A1, excerpt 12 regarding use of off-shift and overtime labor during a malfunction.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 86

Comment: API/AFPM Comments on Proposed BPH NESHAPs, CISWI and NHSM Rules
Page 65

Proposed §63.7501(a)(5):

All possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment and human health; and

Proposed §63.7501(a)(5) sets an impossible requirement that invalidates the possibility of using the affirmative defense and so should be deleted.

This provision is ambiguous at best and impossible to demonstrate at worst. A facility cannot necessarily know in real time what "impacts" or potential impacts emissions might have on air quality, the environment, and human health, nor can a facility do anything other than minimize emissions to minimize the potential environmental impact. In addition, it is impossible to demonstrate that "all possible steps" were taken to do anything. Paragraph (a)(3) already requires a source to minimize the excess emissions. We do not know what other steps the Agency expects or how we could demonstrate that the impacts of those already minimized emissions could be further minimized. This paragraph should be deleted.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 81 regarding affirmative defense provisions.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 88

Comment: Proposed §63.7501(a)(8):

At all times, the facility was operated in a manner consistent with good practices for minimizing emissions; and

Proposed §63.7501(a)(8) is a general requirement and serves no purpose in the affirmative defense provisions since §63.7501(a)(3) already requires that malfunction emissions be minimized. Furthermore, this paragraph deals with the entire facility not just the malfunctioning equipment or operation. Its inclusion in the affirmative defense provisions suggests that you cannot defend yourself for a particular malfunction event if there are excess emissions (e.g., from a startup or shutdown activity) anywhere else in the facility having nothing to do with the malfunctioning operation.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 81 regarding affirmative defense provisions.

Commenter Name: Kerry Kelly

Commenter Affiliation: Waste Management (WM)

Document Control Number: EPA-HQ-OAR-2002-0058-3681-A2

Comment Excerpt Number: 30

Comment: The sheer number of eligibility criteria that must be proven by a “preponderance of evidence and the vague terms such as “unpreventable,” “could not have been foreseen,” and “all possible steps were taken” all but guarantees that no malfunction event will ever meet the criteria. WM suggests modifying the eligibility criteria as follows to make it more reasonable and eliminate such vague language: “To establish that an exceedance of an emission limit or operating standard was the result of a malfunction and therefore not a deviation you must timely meet the notification requirements in paragraph (b) of this section and demonstrate that:

(1) the malfunction:

(i) was not caused by a sudden infrequent and unavoidable failure of air pollution control equipment or failure of a process to operate in a normal or usual manner;

(ii) was not caused by operator error or careless operation;

(iii) was not the result of inadequate design, maintenance or operating procedures; and

(2) Corrective actions were taken immediately to minimize the duration and amount of excess emissions; and

(3) All emission monitoring and control systems were kept in operation if possible in a manner consistent with safety requirements and good air pollution control practices; and

(4) Preventive measures were implemented to address the root cause of the malfunction; and

(5) The root cause analysis and actions in response to the excess emission event were documented in signed contemporaneous log. (b)...”

Response: See the response to comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 81 regarding affirmative defense provisions.

Commenter Name: Lee Zeugin and Lauren Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1

Comment Excerpt Number: 20

Comment: UARG also has some more practical concerns about the way EPA’s affirmative defense is structured. The defense applies to any malfunction as defined in 40 C.F.R. § 63.2, which is:

any sudden, infrequent, and not reasonably preventable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner which causes, or has the potential to cause, the emission limitations in an applicable standard to be exceeded. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Subsection § 63.7501(a)(1)(i) refers to an “unavoidable” failure. Although the difference between “reasonably preventable” and “unavoidable” may seem small, the IB MACT rule seems to require a stronger showing than the definition anticipates in that it leaves room to argue whether a failure could have been prevented even if the acts necessary to do so were “unreasonable.” Other provisions in (a)(1) - (ii) (“[c]ould not have been prevented”), (iii) (“could [not] have been foreseen and avoided, or planned for”), and (a)(5) (“all possible steps”) - also seem to remove the requirement of “reasonableness.” In contrast, other provisions include references to practicability. At a minimum, EPA must revise its criteria consistent with the § 63.2 definition to include the concept of “reasonableness.”

Response: See the response to comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 81 regarding affirmative defense provisions.

Commenter Name: Lee Zeugin and Lauren Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1

Comment Excerpt Number: 21

Comment: Section § 63.7501(a) makes a number of references to “excess emissions.” However, there is no general definition of “excess emissions” in § 63.2. According to § 63.10(c)(7) and (8), “excess emissions” are supposed to be defined in the applicable subpart. Subpart DDDDD contains no such definition. EPA should issue a proposal to define “excess emissions” in the context of any final rule that uses the term.

Response: The EPA has revised § 63.7501(a) to remove the reference to the term 'excess emissions' and thus a definition of this term is no longer necessary. Please see the final rule language for the revised wording of this section.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 79

Comment: The proposal states that: “The affirmative defense shall not be available for claims for injunctive relief.” The preambles to this proposed rule or the March 21, 2011 final rule do not give any explanation for why the affirmative defense would not apply to injunctive relief. If in fact the excess emissions associated with the equipment or process failure are not reasonably preventable, then there is no apparent reason why injunctive relief should be available either. As a matter of law, injunctive relief may not be available in cases where a civil penalty cannot be imposed.⁴⁶

Maintaining liability for injunctive relief renders the affirmative defense particularly ineffective with respect to citizen suits. If the source is even potentially subject to injunctive relief, and therefore could be required to pay the citizen-plaintiff's attorneys fees even if the source successfully demonstrated that it otherwise qualified for the affirmative defense, then the affirmative defense would not accomplish EPA's stated objective of providing relief in situations where the emission limitations cannot be met despite proper design and operation of process and control equipment.

At a minimum, EPA should state that the affirmative defense applies to civil penalties, civil administrative penalties, noncompliance penalties, and injunctive relief, in an action brought by EPA, a state, or a citizen-suit plaintiff. EPA also should reword the "affirmative defense," so that it states that a source "will not be deemed in violation of" the NESHAP for excess emissions or other deviations from the standards, associated with a malfunction event, unless the event, and the source's response to the event, do not meet the criteria spelled out in the regulations.⁴⁷ Configured in that way, this provision should be called something other than an "affirmative defense," such as an "alternative standard for SSM events."

[Footnote 46: See *Sierra Club v. Otter Tail Power Co.*, 615 F.3d 1008 (8th Cir. 2010) (under concurrent remedy doctrine, injunctive relief for a CAA violation is barred when civil penalty is barred by statute of limitations).]

[Footnote 47: *Compare, e.g.*, 40 C.F.R. § 80.613 (stating that persons demonstrating specified defenses "will not be deemed in violation" and are not "deemed liable for a violation" of diesel fuel sulfur program regulations).]

Response: In exercising its authority under section 112 to establish emission standards (at a level that meets the stringency requirements of section 112), the EPA necessarily defines conduct that constitutes a violation. The EPA's view is that the affirmative defense can be viewed as defining two categories of violation. If there is a violation of the emission standard and the source demonstrates that all the elements of the affirmative defense are met, only injunctive relief is available. All other violations of the emission standard are subject to injunctive relief and penalties. The CAA does not require that all violations be treated equally. Further, a citizen suit claim under section 304 allows citizens to commence a civil action against any person alleged to be in violation of "an emission standard or limitation under this chapter." The CAA, however, allows the EPA to establish such "enforceable emission limitations." Thus, the citizen suit provision clearly contemplates enforcement of the standards that are defined by the EPA. As a result, where the EPA defines its emissions limitations and enforcement measures to allow a source the opportunity to prove its entitlement to a lesser degree of violation (not subject to penalties) in narrow, specified circumstances, as the EPA did here, penalties are not "appropriate" under section 304. The affirmative defense criteria are not requirements that a source must meet. In an action to enforce a violation of a standard caused by a malfunction, a source can choose to assert an affirmative defense. The affirmative defense is not relevant to malfunctions that do not result in violations of emission standards.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 99

Comment: Section 63.7501 states: "The affirmative defense shall not be available for claims for injunctive relief." The preamble is silent as to why the affirmative defense would not apply to injunctive relief. If the facility meets the requirements of the affirmative defense provision, why may it not be raised as a defense to a claim for injunctive relief? EPA's assertion to the contrary is unsupported by any explanation.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 79 regarding injunctive relief and affirmative defense.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 102

Comment: Another subjective and particularly problematic requirement is (a)(8) which requires that: "At all times, the *facility* was operated in a manner consistent with good practices for minimizing emissions." ACC strongly objects to EPA reaching beyond the *equipment* that malfunctioned to require a party to prove by a preponderance of the evidence that "at all times, the *facility* was operated in a manner consistent with good practices for minimizing emissions." (Emphasis added.) First, EPA does not define "facility" or "affected facility" in the final major source boiler rule, nor is it included in the definitions at 40 CFR 63.2; common usage of the term facility suggests that it means the entire plant.³² Second, and more importantly, EPA is requiring a party to comply with a requirement that is ambiguous, highly subjective, and therefore impossible to satisfy. This is not reasoned decision-making. ACC notes that in its proposed reconsideration of various provisions of the Chemical Manufacturing Area Source Rule ("CMAS", EPA has revised this requirement and changed the word "facility" to "affected source." (77 Fed. Reg. 4522, January 30, 2012.) If the affirmative defense provision is included in the final reconsidered boiler major source rule, EPA should follow what it has done in CMAS and change "facility" to a more appropriate and defined term, such as "affected source."

[Footnote 32: The term "affected facility" is used in NSPS and is defined in the NSPS General Provisions at 40 CFR 60.2, but the MACT standards in Part 63 use the term "affected source," and the definition of affected source in 40 CFR 63.2 states: "Affected source may be defined differently for part 63 than affected facility and stationary source in parts 60 and 61, respectively." EPA does define the "affected source" in § 63.7490(a) ("the collection at a major source of all existing industrial, commercial, and institutional boilers and process heaters within a subcategory" or "each new or reconstructed industrial, commercial, or institutional boiler or process heater...located at a major source").

Response: We agree with the commenters concerning the use of "affected facility" versus "affected source." As a result, the EPA has changed "affected facility" to "affected source."

Commenter Name: Melvin E. Keener

Commenter Affiliation: Coalition for Responsible Waste Incineration (CRWI)

Document Control Number: EPA-HQ-OAR-2002-0058-3454-A1

Comment Excerpt Number: 8

Comment: EPA should modify the affirmative defense provisions so that it is a "rebuttable presumption."

As EPA knows, malfunctions will occur. Even the best run facilities will have circumstances where events happen that are out of their control. While CRWI believes that EPA must take into account the conditions that occur during malfunctions and establish limits that consider these circumstances, CRWI also agrees that some form of enforcement discretion is needed for malfunctions. As such, we support EPA maintaining a regulatory provision for malfunctions. However, we are concerned that by allowing a facility to interpose an affirmative defense for violations caused by malfunctions implies that the facility is guilty until proven innocent and improperly shifts the burden to the facility. Therefore, CRWI suggests that EPA establish a rebuttable presumption (rather than affirmative defense) where it is presumed any violation occurring during the malfunction was not the operator's fault unless the Agency proves certain facts that are enumerated in the rules. This will allow the Agency to challenge the alleged deviation without compromising the legal rights of either party.

Response: The EPA does not agree that the affirmative defense provisions should be modified in the form of a "rebuttable presumption". The EPA also believes that the burden of proof, if a violation of a standard occurs, appropriately lies with the owner/operator of a facility. The EPA also agrees that the conditions during a malfunction event must be taken into account and believes that the affirmative defense provisions will support this review. For malfunctions, the EPA is finalizing the proposed affirmative defense language for violations of the numerical emission limits that are caused by malfunctions. The EPA recognizes that even equipment that is properly designed and maintained can fail and that such failure can cause a violation of the relevant emission standard. The EPA is including an affirmative defense in the final rule as we have in other recent section 111, section 112, and section 129 rules so as to balance the tension, inherent in many types of air regulation, to ensure adequate compliance while simultaneously recognizing that despite the most diligent of efforts, emission limits may be exceeded under circumstances beyond the control of the source. The EPA must establish emission standards that "limit the quantity, rate, or concentration of emissions of air pollutants on a continuous basis." 42 U.S.C. § 7602(k)(defining "emission limitation and emission standard"). See generally *Sierra Club v. EPA*, 551 F.3d 1019, 1021 (D.C. Cir. 2008) (emissions limitations under must both continuously apply and meet minimum stringency requirements, even during periods of startup, shutdown and malfunction). Thus, the EPA is required to ensure that emissions limitations are continuous. The affirmative defense for malfunction events meets this requirement by ensuring that even where there is a malfunction, the emission limitation is still enforceable through injunctive relief. See generally, *Luminant Generation Co. v EPA*, 2012 U.S. App. LEXIS 15722 (5th Cir. 2012) (upholding EPA's approval of affirmative defense provisions in a CAA State Implementation Plan).

While "continuous" limitations, on the one hand, are required, there is also caselaw indicating that in some situations it is appropriate for the EPA to account for the practical realities of technology. For example, in *Essex Chemical v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973), the D.C. Circuit acknowledged that in setting standards under CAA section 111 "variant provisions" such as provisions allowing for upsets during startup, shutdown and equipment

malfunction “appear necessary to preserve the reasonableness of the standards as a whole and that the record does not support the ‘never to be exceeded’ standard currently in force.” See also, *Portland Cement Association v. Ruckelshaus*, 486 F.2d 375 (D.C.Cir. 1973). Though intervening caselaw such as *Sierra Club v. EPA and the CAA 1977 amendments* calls into question the relevance of these cases today, they support the EPA’s view that a system that incorporates some level of flexibility is reasonable. The affirmative defense simply provides for a defense to civil penalties for excess emissions that are proven to be beyond the control of the source. By incorporating an affirmative defense, the EPA has formalized its approach to upset events. In a Clean Water Act setting, the Ninth Circuit required this type of formalized approach when regulating “upsets beyond the control of the permit holder.” *Marathon Oil Co. v. EPA*, 564 F.2d 1253, 1272-73 (9th Cir. 1977). But see, *Weyerhaeuser Co. v. Costle*, 590 F.2d 1011, 1057-58 (D.C. Cir. 1978) (holding that an informal approach is adequate). The affirmative defense provisions give the EPA the flexibility to both ensure that its emission limitations are “continuous” as required by 42 U.S.C. § 7602(k), and account for unplanned upsets and thus support the reasonableness of the standard as a whole.

Further, the EPA’s view is that the affirmative defense is consistent with CAA sections 113(e) and 304. Section 304 gives district courts jurisdiction “to apply appropriate civil penalties.” Section 113(e)(1) identifies the factors that the Administrator or a court shall take into consideration in determining the amount of a penalty to be assessed only after it has been determined that a penalty is appropriate. The affirmative defense regulatory provision is not relevant to the amount of any penalty to be assessed under section 113(e) because if a court determines that the affirmative defense elements have been established, then a penalty is not appropriate and penalty assessment pursuant to the section 113(e)(1) factors does not occur.

In exercising its authority under section 111 to establish emission standards (at a level that meets the stringency requirements of section 111), the EPA necessarily defines conduct that constitutes a violation. The EPA’s view is that the affirmative defense can be viewed as defining two categories of violation. If there is a violation of the emission standard and the source demonstrates that all the elements of the affirmative defense are met, only injunctive relief is available. All other violations of the emission standard are subject to injunctive relief and penalties. The CAA does not require that all violations be treated equally.

The EPA’s judgment is that the affirmative defense criteria capture the appropriate considerations in determining whether penalties are appropriate when a violation occurs as the result of a malfunction. As noted above, the affirmative defense criteria overlap to some extent with the penalty assessment criteria set forth in section 113(e), but are not identical. For example, size of business is one of the factors listed in section 113(e), but is not reflected in EPA’s affirmative defense. This reflects the EPA’s view that when a violation is caused by a malfunction, the size of the business is not relevant to whether penalties should be excused. If the violation was unavoidable and could not have been prevented, the EPA’s view is that it would be unfair to impose a penalty no matter the size of the business.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 76

Comment: It is unclear where EPA finds the legal authority in the CAA to shift the burden to the regulated community of proving (or disproving) essential elements of an alleged violation. The statute is silent as to the issue and "the ordinary default rule [is] that plaintiffs bear the risk of failing to prove their claims." *Shaeffer v. Weast*, 546 U.S. 49 (2005), quoting *McCormick on Evidence* §337, at 412 ("The burdens of pleading and proof with regard to most facts have and should be assigned to the plaintiff who generally seeks to change the present state of affairs and who therefore naturally should be expected to bear the risk of failure or proof or persuasion"); C. Mueller & L. Kirkpatrick, *Evidence* § 3.1, p. 104 (3d ed. 2003) ("Perhaps the broadest and most accepted idea is that the person who seeks court action should justify the request, which means that the plaintiffs bear the burdens on the elements in their claims"). While the Supreme Court has recognized exceptions such as affirmative defenses, courts retain the authority to establish such rules unless Congress acts to delegate that authority. In this instance, EPA has not provided any statutory authority, or any real justification, for requiring a source to prove its innocence; moreover, to fully demonstrate its innocence within 45 days of the event, without even being charged. Rather, if EPA adopts an approach along the lines of the proposed affirmative defense, it should be stated instead in terms that, once a source has claimed that its excess emissions were related to a malfunction, it will not be considered to be in violation of the standards unless the enforcement authority demonstrates that the source is not entitled to claim the malfunction.

Response: See the responses to comments EPA-HQ-OAR-2002-0058-3510-A1, excerpt 106 and EPA-HQ-OAR-2002-0058-3677-A2, excerpt 90 regarding two-day malfunction notice and 45-day affirmative defense requirements.

The EPA disagrees that the affirmative defense provision will hamper citizen enforcement. First, injunctive relief is still available and the threat of penalties would not deter violations in cases where all of the conditions of the affirmative defense have been satisfied because the affirmative defense criteria ensure that all reasonable steps were taken to prevent a malfunction that causes excess emissions.

Further, litigating whether a source has met the affirmative defense will not burden citizen groups any more or less than would litigating the appropriate penalty amount in the penalty assessment stage of a citizen suit enforcement action, because the 113(e) penalty assessment criteria and the affirmative defense criteria are similar and in fact overlap. For example, the requirement that the Administrator or the court consider "good faith efforts to comply" is bound to generate the type of fact-intensive disputes that the commenter complains of. In addition, several of the affirmative defense criteria are exactly the type of criteria the Administrator or Court might consider in determining whether a source made "good faith efforts to comply." For example, to take advantage of the affirmative defense, the source must prove by a preponderance of the evidence that, among other things, the excess emissions "were caused by an unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner" and "could not have been prevented through careful planning, proper design or better operation and maintenance practices" and "did not stem from any activity or event that could have been foreseen and avoided, or planned for."

Thus, the EPA does not expect the affirmative defense provision to significantly alter the burden of bringing a citizen enforcement action. For those cases that do proceed to trial, even in the absence of this affirmative defense, sources generally raise equitable arguments to argue for a low penalty and citizens often rebut such arguments. Therefore, as a practical matter, the EPA does not expect the affirmative defense provision to materially affect the practice of CAA enforcement.

Commenter Name: Melvin E. Keener

Commenter Affiliation: Coalition for Responsible Waste Incineration (CRWI)

Document Control Number: EPA-HQ-OAR-2002-0058-3454-A1

Comment Excerpt Number: 9

Comment: CRWI suggests that EPA clarify its affirmative defense provisions.

While we prefer EPA use a rebuttable presumption, should the Agency keep the affirmative defense concept, CRWI suggests the following modifications to the language to make it more usable. CRWI understands that most of the provisions EPA has proposed for the affirmative defense comes from earlier guidance memos. While these provisions were in guidance, the Agency did not need to be careful of the wording since they were only guidance and did not have the weight of regulation. However, if the Agency wants to codify this guidance into regulatory language, several changes are needed. For example, EPA should drop the reference to "any" activity in this paragraph. There are also several references to "All" that would make it difficult to satisfy the requirements of an affirmative defense. In addition, the language in the provision is contradictory. In paragraph (a), the phrase "preponderance of evidence" is used while later in that paragraph (iii), the language refers to "any activity" meaning that more than a preponderance of evidence is needed. This same trend occurs in paragraphs (5) – EPA-HQ-OAR-2002-0058 8

"All possible," (6) "All," (7) "All of the actions," and (8) "At all times." While "all" would include "preponderance," "preponderance" does not mean all of the time. CRWI suggests that the phrase "preponderance of evidence" is adequate and the references to "all" and "any" in the later paragraphs should be modified.

Response: See DCN EPA-HQ-OAR-2002-0058-3454-A1, Excerpt No. 8 and EPA-HQ-OAR-2002-0058-3677, Excerpt No. 76 regarding rebuttable presumption and affirmative defense. See DCN-EPA-HQ-OAR-2002-0058-3677-A2, Excerpt No. 81 regarding affirmative defense provisions

Commenter Name: Michael L. Krancer

Commenter Affiliation: Pennsylvania Department of Environmental Protection (DEP)

Document Control Number: EPA-HQ-OAR-2002-0058-3507-A1

Comment Excerpt Number: 18

Comment: The EPA has finalized affirmative defense provisions for malfunctions and as part of the reconsideration proposal is soliciting comments on the affirmative defense provisions that were included in the final rule. The March 21, 2011, final rule defines affirmative defense as follows: "Affirmative defense means, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and

the merits of which are independently and objectively evaluated in a judicial or administrative proceeding." Ultimately, to assert the affirmative defense, the owner or operator of the source must prove by a preponderance of the evidence that excess emissions were caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment or a process to operate in a normal or usual manner.

The DEP believes that the burden of proof rests with the owners or operators of the sources to show that the emission limit exceedances are beyond their control and that they took every step necessary to prevent such occurrences from taking place. However, the criteria specified in section 63.7501 (a)(1)(ii) and section 63.7501 (a)(1)(iii) are too subjective and may preclude owners and operators from using the affirmative defense provisions.

Response: See DCN-EPA-HQ-OAR-2002-0058-3677-A2, Excerpt No. 81 regarding affirmative defense provisions. See DCN EPA-HQ-OAR-2002-0058-3454-A1, Excerpt No. 8 and EPA-HQ-OAR-2002-0058-3677, Excerpt No. 76 regarding rebuttable presumption and affirmative defense.

Commenter Name: Lorraine Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1
Comment Excerpt Number: 96

Comment: EPA has cited no legal authority for its use of affirmative defense requirements that inappropriately and unlawfully shift the burden to the facility to prove by a preponderance of the evidence that any excess emissions were caused by a true malfunction *and* that the facility meets all of the other specified factors in § 63.7501. EPA's affirmative defense places the facility in the position of proving its innocence, rather than EPA or other regulatory authority proving that the facility violated the CAA.

Response: See DCN EPA-HQ-OAR-2002-0058-3454-A1, Excerpt No. 8 and EPA-HQ-OAR-2002-0058-3677, Excerpt No. 76 regarding rebuttable presumption and affirmative defense.

Commenter Name: Lorraine Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1
Comment Excerpt Number: 97

Comment: EPA states that the affirmative defense may be raised to a "claim for civil penalties" but does not define "civil penalties". It is unclear, for example, whether this claim is meant to include a "civil administrative penalty" imposed by EPA under § 113(d) of the CAA? A "noncompliance" penalty sought under § 120 of the CAA? A "civil penalty" imposed by a court?

Response: See the responses to comments EPA-HQ-OAR-2002-0058-3454-A1, excerpt 8 and EPA-HQ-OAR-2002-0058-3677, excerpt 76 regarding rebuttable presumption and affirmative defense.

The affirmative defense applies to civil penalties, including civil administrative penalties and penalties under section 120, but does not apply to injunctive relief. **Commenter Name:** LESLIE SUE RITTS

Commenter Affiliation: National Environmental Development Association's Clean Air Project (NEDA/CAP)

Document Control Number: EPA-HQ-OAR-2002-0058-3529-A1

Comment Excerpt Number: 11

Comment: Subpar. (1) of the affirmative defense requires that the operator must demonstrate that excess emissions: (i) Were caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner, and (ii) *Could not have been prevented through careful planning, proper design or better operation and maintenance practices.* NEDA/CAP appreciates that EPA understands that it is not always possible to design equipment to avoid malfunctions and while this reveals an error in EPA's logic for considering malfunctions to be violations of the regulation, it is vital for the regulation to recognize unavoidable events. Nonetheless, NEDA/CAP objects to the regulatory requirement that shifts to the operator the burden of proving that equipment could not have been better designed; it turns the doctrine of "innocent until proven guilty" on its head. We therefore recommend that EPA delete the phrase "proper design" from Subpar. 1 of the affirmative defense.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 81 regarding affirmative defense provisions. See the response to comment EPA-HQ-OAR-2002-0058-3454-A1, excerpt 8 and EPA-HQ-OAR-2002-0058-3677, excerpt 76 regarding rebuttable presumption and affirmative defense.

Commenter Name: Vickie Woods

Commenter Affiliation: Division of Air Quality, North Carolina Department of Environment and Natural Resources (NCDENR)

Document Control Number: EPA-HQ-OAR-2002-0058-3663-A2

Comment Excerpt Number: 21

Comment: Where defendant has the burden of proof, for which its defense merits are objectively evaluated in administrative proceeding.

NC DAQ concurs with this approach for malfunctions. While NC DAQ recognizes that malfunctions occur and that certain types of malfunctions may be expected to occur periodically over a unit's life, NC DAQ agrees that the facility operator is obligated to provide proof that the malfunction was unavoidable, that the period of operation in malfunction was minimized and that emissions were minimized to the extent possible during the period of malfunction.

Response: See the responses to comments EPA-HQ-OAR-2002-0058-3454-A1, excerpt 8 and EPA-HQ-OAR-2002-0058-3677, excerpt 76 regarding rebuttable presumption and affirmative defense.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and

Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 77

Comment: Even if the proposed affirmative defense were not unreasonably vague and restrictive, as discussed in the following portion of these comments, being able to assert a defense obviously is not the same as complying with emission limitations that are properly set in accordance with CAA section 112. Although a source believes it qualifies for the affirmative defense, it may be considered to have violated the standards—and may have to report violations, certify noncompliance, etc.—until there has been an enforcement proceeding and the source has successfully asserted the affirmative defense. The affirmative defense places the source in the position of proving its innocence, rather than EPA or another enforcement authority having to prove that the source violated the CAA.

Response: See the responses to comments EPA-HQ-OAR-2002-0058-3454-A1, excerpt 8 and EPA-HQ-OAR-2002-0058-3677, excerpt 76 regarding rebuttable presumption and affirmative defense.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 80

Comment: The affirmative defense content provisions of proposed §63.7501(a) are unworkable and should be revised if not deleted.

On page 80615 of this proposal, EPA requests comment on the affirmative defense provisions. As we have indicated in previous comments on various rules, these provisions are so broad that they provide no practical value to affected parties. We explain our concern in more detail below.

The affirmative defense is based on the presumption that all malfunctions are violations without providing for any due process. If the affirmative defense is finalized, EPA should separate it from that presumption and make clear that a source's use of the affirmative defense is not an admission by the source that the malfunction was a violation.

Response: See the responses to comments EPA-HQ-OAR-2002-0058-3454-A1, excerpt 8 and EPA-HQ-OAR-2002-0058-3677, excerpt 76 regarding rebuttable presumption and affirmative defense.

Commenter Name: Kerry Kelly

Commenter Affiliation: Waste Management (WM)

Document Control Number: EPA-HQ-OAR-2002-0058-3681-A2

Comment Excerpt Number: 27

Comment: Although EPA acknowledges that malfunctions occur in well operated and maintained facilities equipped with the best technologies, EPA's affirmative defense concept

essentially presumes that malfunctions never occur. Under the rule as written, any emissions occurring above the limits set using emission data obtained exclusively during normal operation (emphasis added) are considered deviations, regardless of the underlying root cause of the emissions. The reality is that malfunctions infrequently occur even on the best designed, maintained and operated units. Therefore, a facility should not be presumed guilty of having a deviation in the first place if it has experienced a legitimate malfunction.

Response: See the responses to comments EPA-HQ-OAR-2002-0058-3454-A1, excerpt 8 and EPA-HQ-OAR-2002-0058-3677, excerpt 76 regarding rebuttable presumption and affirmative defense.

Commenter Name: Mark Anthony

Commenter Affiliation: Alyeska Pipeline Service Company

Document Control Number: EPA-HQ-OAR-2002-0058-3684-A2

Comment Excerpt Number: 6

Comment: Alyeska strongly agrees with the APIINPRA comments regarding the heavy handed treatment of malfunctions in the proposed rule. The proposed text implies a presumption of guilt and imposes an unreasonable burden on the facility for each incident that may occur. The simple fact is that malfunctions will occur and no amount of planning or expense can completely eliminate them. Alyeska agrees that if a malfunction occurs and an emission limit is exceeded that the agency (either EPA or the Title V delegated agency) should be provided notification of the event including a description of the event and the corrective actions taken at the time. However, Alyeska believes that the level of information necessary to "assert the affirmative defense" should only be necessary 1) if a facility has a history of having repetitive "similar type" exceedences, and 2) the information is specifically requested by the agency. The EPA and delegated state agencies should take an enforcement discretion approach instead of treating every incident as an enforcement case.

Response: See the responses to comments EPA-HQ-OAR-2002-0058-3454-A1, excerpt 8 and EPA-HQ-OAR-2002-0058-3677, excerpt 76 regarding rebuttable presumption and affirmative defense.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 78

Comment: It is unclear how the affirmative defense will apply to enforcement actions by state and local governments, or to private citizen enforcement actions under CAA section 304. The March 21, 2011 final rule preamble speaks only in terms of application of the affirmative defense in an EPA enforcement action.⁴⁴ An affirmative defense should clearly state that it is applicable to enforcement actions by states or citizen-suit plaintiffs, as well.

[Footnote 44: 76 FR 15613]

Response: See the response to comment EPA-HQ-OAR-2002-0058-3510-A1, excerpt 97 regarding affirmative defense and civil penalties. See the response to comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 76 regarding citizen enforcement.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 98

Comment: It is unclear how the affirmative defense would apply to enforcement actions by state and local governments, or to private citizen enforcement actions brought under § 304 of the CAA. While in no way endorsing EPA's affirmative defense provision, ACC believes that if retained by the Agency after reconsideration, the provision should clearly state that it is applicable to *any* enforcement action.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 78 regarding affirmative defense and enforcement actions.

105A. Civil Penalties

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 52

Comment: The statute makes clear how the courts are to assess civil penalties, whether a case is brought by EPA or a citizen. 42 U.S.C. § 7413(e). Congress plainly intended citizens to be able to enforce emission standards under the CAA using the full range of civil enforcement mechanisms available to the government, and, in the HAP context, subject only to the limitation that government not be "diligently prosecuting" its own civil enforcement action, CAA § 304(b)(1)(B), 42 U.S.C. § 7604(b)(1)(B). EPA's rule proposal, by shifting this careful balance and contravening these mandates, violates the CAA.

Response: The EPA does not agree that the affirmative defense provisions should be modified in the form of a "rebuttable presumption". The EPA also believes that the burden of proof, if a violation of a standard occurs, appropriately lies with the owner/operator of a facility.

The EPA also agrees that the conditions during a malfunction event must be taken into account and believes that the affirmative defense provisions will support this review. For malfunctions, the EPA is finalizing the proposed affirmative defense language for violations of the numerical emission limits that are caused by malfunctions. The EPA recognizes that even equipment that is properly designed and maintained can fail and that such failure can cause a violation of the relevant emission standard. The EPA is including an affirmative defense in the final rule as we have in other recent section 111, section 112, and section 129 rules so as to balance the tension, inherent in many types of air regulation, to ensure adequate compliance while simultaneously recognizing that despite the most diligent of efforts, emission limits may be exceeded under circumstances beyond the control of the source. The EPA must establish emission standards that

“limit the quantity, rate, or concentration of emissions of air pollutants on a continuous basis.” 42 U.S.C. § 7602(k)(defining “emission limitation and emission standard”). See generally *Sierra Club v. EPA*, 551 F.3d 1019, 1021 (D.C. Cir. 2008) (emissions limitations under must both continuously apply and meet minimum stringency requirements, even during periods of startup, shutdown and malfunction). Thus, the EPA is required to ensure that emissions limitations are continuous. The affirmative defense for malfunction events meets this requirement by ensuring that even where there is a malfunction, the emission limitation is still enforceable through injunctive relief.

While “continuous” limitations, on the one hand, are required, there is also caselaw indicating that in some situations it is appropriate for the EPA to account for the practical realities of technology. For example, in *Essex Chemical v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973), the D.C. Circuit acknowledged that in setting standards under CAA section 111 “variant provisions” such as provisions allowing for upsets during startup, shutdown and equipment malfunction “appear necessary to preserve the reasonableness of the standards as a whole and that the record does not support the ‘never to be exceeded’ standard currently in force.” See also, *Portland Cement Association v. Ruckelshaus*, 486 F.2d 375 (D.C.Cir. 1973). Though intervening caselaw such as *Sierra Club v. EPA* and the CAA 1977 amendments calls into question the relevance of these cases today, they support the EPA’s view that a system that incorporates some level of flexibility is reasonable. The affirmative defense simply provides for a defense to civil penalties for excess emissions that are proven to be beyond the control of the source. By incorporating an affirmative defense, the EPA has formalized its approach to upset events. In a Clean Water Act setting, the Ninth Circuit required this type of formalized approach when regulating “upsets beyond the control of the permit holder.” *Marathon Oil Co. v. EPA*, 564 F.2d 1253, 1272-73 (9th Cir. 1977). But see, *Weyerhaeuser Co. v. Costle*, 590 F.2d 1011, 1057-58 (D.C. Cir. 1978) (holding that an informal approach is adequate). The affirmative defense provisions give the EPA the flexibility to both ensure that its emission limitations are “continuous” as required by 42 U.S.C. § 7602(k), and account for unplanned upsets and thus support the reasonableness of the standard as a whole.

Further, the EPA’s view is that the affirmative defense is consistent with CAA sections 113(e) and 304. Section 304 gives district courts jurisdiction “to apply appropriate civil penalties.” Section 113(e)(1) identifies the factors that the Administrator or a court shall take into consideration in determining the amount of a penalty to be assessed only after it has been determined that a penalty is appropriate. The affirmative defense regulatory provision is not relevant to the amount of any penalty to be assessed under section 113(e) because if a court determines that the affirmative defense elements have been established, then a penalty is not appropriate and penalty assessment pursuant to the section 113(e)(1) factors does not occur.

In exercising its authority under section 111 to establish emission standards (at a level that meets the stringency requirements of section 111), the EPA necessarily defines conduct that constitutes a violation. The EPA’s view is that the affirmative defense is part of the emission standard and defines two categories of violation. If there is a violation of the emission standard and the source demonstrates that all the elements of the affirmative defense are met, only injunctive relief is available. All other violations of the emission standard are subject to injunctive relief and penalties. The CAA does not require that all violations be treated equally.

The EPA's judgment is that the affirmative defense criteria capture the appropriate considerations in determining whether penalties are appropriate when a violation occurs as the result of a malfunction. As noted above, the affirmative defense criteria overlap to some extent with the penalty assessment criteria set forth in section 113(e), but are not identical. For example, size of business is one of the factors listed in section 113(e), but is not reflected in EPA's affirmative defense. This reflects the EPA's view that when a violation is caused by a malfunction, the size of the business is not relevant to whether penalties should be excused. If the violation was unavoidable and could not have been prevented, the EPA's view is that it would be unfair to impose a penalty no matter the size of the business. The EPA disagrees that the affirmative defense provision will hamper citizen enforcement. First, injunctive relief is still available and the threat of penalties would not deter violations in cases where all of the conditions of the affirmative defense have been satisfied because the affirmative defense criteria ensure that all reasonable steps were taken to prevent a malfunction that causes excess emissions. Further, litigating whether a source has met the affirmative defense will not burden citizen groups any more or less than would litigating the appropriate penalty amount in the penalty assessment stage of a citizen suit enforcement action, because the 113(e) penalty assessment criteria and the affirmative defense criteria are similar and in fact overlap. For example, the requirement that the Administrator or the court consider "good faith efforts to comply" is bound to generate the type of fact-intensive disputes that the commenter complains of. In addition, several of the affirmative defense criteria are exactly the type of criteria the Administrator or Court might consider in determining whether a source made "good faith efforts to comply." For example, to take advantage of the affirmative defense, the source must prove by a preponderance of the evidence that, among other things, the excess emissions "were caused by an unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner" and "could not have been prevented through careful planning, proper design or better operation and maintenance practices" and "did not stem from any activity or event that could have been foreseen and avoided, or planned for." Thus, the EPA does not expect the affirmative defense provision to significantly alter the burden of bringing a citizen enforcement action. For those cases that do proceed to trial, even in the absence of this affirmative defense, sources generally raise equitable arguments to argue for a low penalty and citizens often rebut such arguments. Therefore, as a practical matter, the EPA does not expect the affirmative defense provision to materially affect the practice of CAA enforcement.

In exercising its authority under section 112 to establish emission standards (at a level that meets the stringency requirements of section 112), the EPA necessarily defines conduct that constitutes a violation. The EPA's view is that the affirmative defense is part of the emission standard and defines two categories of violation. If there is a violation of the emission standard and the source demonstrates that all the elements of the affirmative defense are met, only injunctive relief is available. All other violations of the emission standard are subject to injunctive relief and penalties. The CAA does not require that all violations be treated equally. Further, a citizen suit claim under section 304 allows citizens to commence a civil action against any person alleged to be in violation of "an emission standard or limitation under this chapter." The CAA, however, allows the EPA to establish such "enforceable emission limitations." Thus, the citizen suit provision clearly contemplates enforcement of the standards that are defined by the EPA. As a result, where the EPA defines its emissions limitations and enforcement measures to allow a source the opportunity to prove its entitlement to a lesser degree of violation (not subject to

penalties) in narrow, specified circumstances, as the EPA did here, penalties are not “appropriate” under section 304.

The EPA’s view is that an affirmative defense to civil penalties for exceedances of applicable emission standards during periods of malfunction appropriately balances competing concerns. On the one hand, citizen enforcers are concerned about additional complications in their enforcement actions. On the other hand, industrial sources are concerned about being penalized for violations caused by malfunctions that could not have prevented and were otherwise appropriately handled (as reflected in the affirmative defense criteria). The EPA has utilized its Section 301(a)(1) authority to issue regulations necessary to carry out the Act in a manner that appropriately balances these competing concerns.

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 53

Comment: The affirmative defense that EPA proposes to allow in case of malfunctions goes directly against congressional intent in two ways. First, Congress expressed a clear intent as to how judges should determine the size of civil penalties whenever they are sought and thus Congress 20 flatly barred EPA from limiting when civil penalties can be assessed. See *Chevron, U.S.A., Inc. v. Natural Res. Def. Council, Inc.*, 467 U.S. 837, 842-43 (1984). In this proposal, EPA acts outside of its delegated authority to limit civil penalties available in citizen suits or its own enforcement actions. Second, the proposal will impermissibly chill citizen participation, and the ability to win an effective, deterrent remedy, in CAA enforcement actions.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3511-A1, excerpt 52 regarding civil penalties.

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 55

Comment: The CAA grants EPA minimal discretion that only applies to administrative penalties, allowing EPA to "compromise, modify, or remit, with or without conditions, any administrative penalty which may be imposed under [subsection 113(d)]." 42 U.S.C. § 7413(d)(2)(B). However, there is no similar grant of authority to EPA to compromise, modify or limit civil penalties that a court may impose under section 113(e) or section 304. Section 304(a), 42 U.S.C. § 7604(a), grants courts the sole authority "to apply appropriate civil penalties" in citizen suits. The explicit reference to EPA's ability to modify penalties in one subsection and its absence in the other subsection of the same provision can only be understood as an intentional decision by Congress that EPA cannot contravene by rule.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3511-A1, excerpt 52 regarding civil penalties.

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 56

Comment: Citizen participation in CAA enforcement also will be hampered, in violation of citizens' rights to protect themselves from pollution and in direct conflict with congressional intent. The affirmative defense would likely be used on a routine basis by polluters seeking to avoid penalties, just as the malfunction exemption was. As a result, citizens who seek civil penalties against polluters in order to protect themselves and achieve the Act's goals may be forced to engage in fact-intensive disputes over the cause of emission violations and adequacy of responsive measures - an outcome Congress intended to prevent with the simple straightforward enforcement and penalty provisions in the Clean Air Act. As a result, enforcement of the Act could suffer, for civil penalties provide a powerful deterrent to violators as Congress intended.

Thus, the affirmative defense also runs counter to two clearly expressed intentions of Congress: (1) the burden it places on citizens makes it less likely that they will enforce the Act, *see, e.g., Pennsylvania v. Del. Valley Citizens' Council for Clean Air*, 478 U.S. 546, 560 (1986); and (2) several of the factors at issue in the affirmative defense undercut Congress's intent that citizen suit enforcement should avoid re-delving into "technological or other considerations," *NRDC v. Train*, 510 F.2d 692, 700 (D.C. Cir. 1974). Both result from the technical burden EPA imposes on citizens with the affirmative defense, and both render the defense impermissible.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3511-A1, excerpt 52 regarding civil penalties.

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 57

Comment: There is simply no need for an affirmative defense to penalties 21 to be written into the regulations and cause the harm that will result. EPA has discretion to decide what cases to prosecute, to consider settlements, and to request civil penalties in a case-by-case manner, as long as it acts consistent with the Clean Air Act to protect clean air as its top priority, see 42 U.S.C. § 7401. Promulgating this affirmative defense is equivalent to giving polluters "get out of jail free" cards for serious emission exceedances and MACT violations. Polluters are likely to claim that any violation of the standard is due to a malfunction in order to evade the requirements. Allowing polluters to evade financial penalties - which are the real teeth of the standards - through this type of measure is likely to lead to polluters simply ignoring or factoring potential standard violations into their cost of doing business, rather than actually trying to prevent malfunctions and violations of the standards as a way to avoid financial losses from the application of penalties.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3511-A1, excerpt 52 regarding civil penalties.

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 54

Comment: The affirmative defense is fatally flawed because EPA cannot decide when civil penalties will not be allowed. The CAA itself spells out the only limits that Congress intended to impose on citizens' ability to seek and recover penalties in enforcement suits under CAA § 304, 42 U.S.C. § 7604. See 42 U.S.C. § 7413(e). By attempting to impose additional agency-created limits, EPA exceeds its authority.

Congressional intent on civil penalties is clear—they are a remedy available to citizen plaintiffs, and the Act gives judges a list of factors to consider in assessing them. As such, EPA cannot interpret the statute to contravene that intent. By attempting to rewrite this provision, via regulation, EPA has done just that.

Response: See DCN EPA-HQ-OAR-2002-0058-3511-A1, Excerpt 52 regarding civil penalties.

The EPA has determined that CAA section 112 does not require that emissions that occur during periods of malfunction be factored into development of CAA section 112 standards. As the EPA further explained, accounting for malfunctions would be difficult, if not impossible, given the myriad different types of malfunctions that can occur across all sources in the category and given the difficulties associated with predicting or accounting for the frequency, degree, and duration of various malfunctions that might occur. Setting work practice standards under section 112 presents the same issues as setting numerical emission limits given the varied nature of malfunctions. Thus EPA does not agree with commenter's suggestion that EPA apply work practices for malfunction events. EPA recognizes that even equipment that is properly designed and maintained can sometimes fail and that such failure can sometimes cause an exceedance of the relevant emission standard. (See, e.g., State Implementation Plans: Policy Regarding Excessive Emissions During Malfunctions, Startup, and Shutdown (Sept. 20, 1999); Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions (Feb. 15, 1983)). EPA, therefore, added an affirmative defense to civil penalties for exceedances of numerical emission limits that are caused by malfunctions. The affirmative defense criteria are not requirements that a source must meet. In an action to enforce a violation of a standard caused by a malfunction, a source can choose to assert an affirmative defense. The affirmative defense is not relevant to malfunctions that do not result in violations of emission standards.

EPA disagrees with comments that criticize the affirmative defense criteria as being overly vague or unduly restrictive and complex. The EPA believes that courts are well equipped and often do evaluate and apply the type of criteria set forth in the affirmative defense. Many of the conditions were modeled after the conditions of the affirmative defense in the EPA's SIP SSM policy, which several states have adopted into their SIPs. (See, e.g., State Implementation Plans: Policy Regarding Excessive Emissions During Malfunctions, Startup, and Shutdown (Sept. 20, 1999); Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions (Feb. 15, 1983)). We do not have any indication that parties to enforcement proceedings have had any significant difficulties applying the terms of these SIP affirmative defenses. In addition, the EPA's view is that use of consistent terms in establishing affirmative defense regulations and

policies across various CAA programs will promote consistent implementation of those rules and policies.

EPA explained its view that a formal approach of an affirmative defense was preferable to an informal enforcement discretion approach for the following reasons: “First, the existence of a formal process better informs the public of the policy and factual issues which will underline enforcement of the standards. Second, affected industries which are making good-faith efforts to meet the standards will on the whole welcome a regularized means of informing the Agency in detail of the circumstances surrounding unavoidable emission excesses. Third, the Agency expects to benefit substantially from the information it will gain about the operation of the processes in question, for both future enforcement and standard setting.” 37 Fed. Reg. 17,214, 17,214-15 (Aug. 25, 1972). The affirmative defense is not an informal enforcement discretion approach of the type that EPA rejected in 1972 and provides the benefits associated with the formalized approach that EPA identified in its 1972 proposal. *See, Mont. Sulphur & Chem. Co. v. United States EPA*, 2012 U.S. App. LEXIS 1056 (5th cir. Jan 19, 2012)(in rejecting industry argument that reliance on the affirmative defense was not adequate, court stated “[h]owever, here the EPA does not rely on enforcement discretion alone, but specifically promulgates an affirmative defense in the FIP, which clearly defines the requirements to avoid penalties.”).

Recordkeeping and Reporting Requirements

13Z. Out of Scope: Recordkeeping and Reporting Requirements

Commenter Name: Michael Bradley

Commenter Affiliation: The Clean Energy Group

Document Control Number: EPA-HQ-OAR-2002-0058-3495-A1

Comment Excerpt Number: 10

Comment: The Clean Energy Group appreciates EPA's clarification that the Agency will not enforce initial notification requirements that have passed while the major source rule was stayed.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Arthur N. Marin

Commenter Affiliation: Northeast States for Coordinated Air Use Management (NESCAUM)

Document Control Number: EPA-HQ-OAR-2002-0058-3506-A1

Comment Excerpt Number: 6

Comment: Under the current and proposed rules, emission sources make their own determination about whether they are exempt from the boiler rules, but are not required to maintain records to support their determination. This creates an untenable situation for state enforcement staff who must determine whether a given unit is subject to the rules. Without adequate recordkeeping requirements, agencies will find it impossible to enforce these rules. Having emission sources maintain these records will assure that enforcement agencies can accurately assess the applicability determinations. Records should include the reasoning for

determining whether each unit is exempt from the requirements of the area source rule, e.g., whether it can be classified as a residential or temporary boiler. Similarly, sources should be required to maintain records of fuel use by units. This will assist enforcement officials in determining the compliance and exemption status of sources.

To address these issues, NESCAUM recommends that EPA insert language requiring sources asserting exemptions from the area and major source boiler rules to maintain records to support their exemption determination. In addition, NESCAUM recommends that sources be required to maintain records of fuel use for each unit.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 141

Comment: The Boiler MACT requires several plans to be submitted by facilities using various compliance options. An emissions averaging plan must be submitted at least 180 days prior to the date that the facility intends to demonstrate compliance using emissions averaging. A site-specific fuel analysis plan must be submitted at least 60 days prior to the initial performance test. There are likely to be hundreds of such submissions, since fuel analysis is anticipated to be widely used as a component of demonstrating compliance with numerical emission limits. It is highly unlikely all these plans can be reviewed before the initial compliance date and, unless the source is deviating from the methodologies specified in the rule, there is no reason for such a review. Thus, we recommend that approval only be required where the source is requesting to use an alternative analytical methodology. EPA should also make it clear in the final rule that if the permitting authority does not respond to the facility with approval or disapproval of the plan prior to the compliance demonstration, then the plan is considered approved.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Sarah Hedrick

Commenter Affiliation: Verso Paper Corp.

Document Control Number: EPA-HQ-OAR-2002-0058-3537-A2

Comment Excerpt Number: 9

Comment: Pulp and paper manufacturing facilities in the US must be efficient and globally costcompetitive.

The proposed rule's data collection (Section 63.7555 recordkeeping) and reporting requirements in Section 63.7550 include redundant reporting burdens. Redundant requirements include having to re-submit performance test and fuel analysis results which have already been submitted to the delegated authority. This is labor intensive and overly burdensome. Facilities cannot compete globally when encumbered with such costly, excessive, and unreasonable regulatory obligations.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Sarah Hedrick

Commenter Affiliation: Verso Paper Corp.

Document Control Number: EPA-HQ-OAR-2002-0058-3537-A2

Comment Excerpt Number: 10

Comment: Section 63.7550 specifies compliance reporting requirements. Section 63.7550(c)(5) requires a summary of annual performance test results and an analysis of fuel sampling. This information would have been previously sent to the delegated authority as required in section 63.7575. This is an additional, burdensome requirement for facilities with limited resources. The requirement should be removed from this section.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Sarah Hedrick

Commenter Affiliation: Verso Paper Corp.

Document Control Number: EPA-HQ-OAR-2002-0058-3537-A2

Comment Excerpt Number: 11

Comment: Section 63.7550(d) also has redundant performance test reporting requirements which should be removed from this section.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: John M. Cullen

Commenter Affiliation: Masco Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3661-A2

Comment Excerpt Number: 14

Comment: Initial notification requirements in 63.7545(b) for existing boilers and process heaters are not appropriate for natural gas-fired boilers and the rules should be clarified to exclude boilers that do not have emission limits.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 153

Comment: The proposal requires submission of an Initial Notification no later than 120 calendar days after a facility becomes subject to rule , even if an initial notification was previously submitted. We see no reason for having to file another initial notice since the only information it provides is that certain facilities are subject to the subpart. If initial notifications were submitted in 2004 or in response to the 2011 rule, why is it necessary to submit additional notifications? EPA and permitting authorities were notified of BPH NESHAP applicability and, in many cases, have already reflected that applicability in permits. A new initial notice submittal serves no purpose and should only be required if a facility was not previously subject to the rule and has not previously submitted an initial notice.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Janice E. Nolen

Commenter Affiliation: American Lung Association

Document Control Number: EPA-HQ-OAR-2002-0058-3679-A2

Comment Excerpt Number: 14

Comment: Public records for monitoring and compliance with emissions limits. The Lung Association recommends that the records and reports of monitoring and compliance measures for emissions limits be made easily and readily accessible to the public. The public has an established right to know about the emissions of toxic substances. For 25 years, EPA has required companies to make public information on toxic chemicals released into the community through the Toxic Release Inventory (TRI). We support a system similar to TRI, where facilities are required to report toxic emissions to the database and make data relating to those emissions available online.

EPA should require boiler operators to publicly disclose and report all monitoring data and compliance documentation—including with required work practices standards—and submit those data reports to EPA for public access online. These would include data and results from performance tests of facilities and emissions that occur during malfunctions of boiler equipment. Communities have a right to know what toxic air pollutants are emitted by boilers and incinerators, the quantities of each type of pollutant being emitted, when those emissions are occurring, particularly when the emissions exceed limits set by EPA.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: M.L. Steele

Commenter Affiliation: CraftMaster Manufacturing, Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3814-A1

Comment Excerpt Number: 24

Comment: §63.7545(h). Thirty days notice is required for a fuel switch that would result in the applicability of a different subcategory. If a change in biomass firing method by a unit capable of firing in more than one biomass subcategory would trigger this notice requirement, this is further justification for better guidance on the applicability of the biomass subcategories. 30-day notice

would not be practical for such a unit because changes in biomass firing method can occur on an hourly basis.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Gretchen Brewer

Commenter Affiliation: PT AirWatchers

Document Control Number: EPA-HQ-OAR-2002-0058-3825-A1

Comment Excerpt Number: 6

Comment: Fuel reporting requirements -- regular analysis reports with breakouts by fuel types and ratios are increasingly important as boilers are using shifting varieties and mixes of fuels, such as waste fuel oils, construction and demolition debris, tires (!), medical and agricultural wastes, and pretty much anything that can be burned. The given mix at any time profoundly affects the resulting pollution, and the effects that it has on those of use who have to breathe it.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Compliance

14A. Emissions Averaging: Output-Based Standards

Commenter Name: Lisa Jacobson

Commenter Affiliation: Business Council for Sustainable Energy (BCSE)

Document Control Number: EPA-HQ-OAR-2002-0058-3497-A1

Comment Excerpt Number: 1

Comment: *Clarifying that facilities may simultaneously adopt the alternative output-based compliance standard and average emissions.* BCSE members expressed concern in reaction to the March 21, 2011 rule's apparent prohibition against combining both an output-based emissions standard and emissions averaging. The Council commends EPA for correcting this oversight in the re-proposed rule by allowing averaging for units that elect to comply with the output-based standards and for providing clear direction on how a facility may opt simultaneously for output-based emissions limitations and emissions averaging. As EPA notes in the re-proposed rule, "there is no technical reason why averaging of output-based limits is inappropriate."

Response: The EPA thanks the commenter for their support. The commenter is referring to the addition of equations 1b and 3b in §63.7522 (Can I use emissions averaging to comply with this subpart?) of the December 2011 Reconsideration Proposal which were proposed to be added to clarify that averaging of the output-based limits was allowed.

Commenter Name: Peter Pagano

Commenter Affiliation: American Iron and Steel Institute (AISI)

Document Control Number: EPA-HQ-OAR-2002-0058-3490-A1

Comment Excerpt Number: 32

Comment: The emissions averaging provision should be expanded to provide operational flexibility and lowest compliance costs.

Affected parties may choose to comply with output-based emission limits in lieu of input-based standards for boilers that generate steam. Although the Reconsidered Rule does not provide for averaging, EPA recognizes that there is no technical reason why averaging of output-based limits should not be included. We agree and strongly encourage EPA to include emissions averaging in its output-based standards, as originally argued by the Council of industrial Boiler Owners.⁴¹

[Footnote]

(41) Comment attachment submitted by Robert D. Bessette, President, CIBO, EPA-HQOAR-2002-0058-2702; Revised Methodology for Estimating Cost and Emissions Impacts for Industrial, Commercial, Institutional Boilers and Process Heaters NESHAP- Major Source, EPA-HQ-OAR-2002-0058-3259.

Response: The EPA thanks the commenter for their support. See the response to comment EPA-HQ-OAR-2002-0056-3497-A1, excerpt 1 regarding output-based standards.

Commenter Name: Michael Bradley

Commenter Affiliation: The Clean Energy Group

Document Control Number: EPA-HQ-OAR-2002-0058-3495-A1

Comment Excerpt Number: 6

Comment: Additionally, EPA notes that, due to time constraints, the Agency did not finalize a process by which units complying with the output-based standards could utilize the emissions averaging provisions. In this rulemaking, EPA proposes to specifically allow units to use emissions averaging regardless of compliance with input- or output-based standards. EPA also proposes to include methodology to allow units that only generate electricity to comply with output-based standards. The Clean Energy Group supports this change to allow units complying with output-based standards to utilize all compliance flexibilities.

Response: The EPA thanks the commenter for their support. See the response to comment EPA-HQ-OAR-2002-0056-3497-A1, excerpt 1 regarding output-based standards.

Commenter Name: Michael L. Krancer

Commenter Affiliation: Pennsylvania Department of Environmental Protection (DEP)

Document Control Number: EPA-HQ-OAR-2002-0058-3507-A1

Comment Excerpt Number: 5

Comment: The EPA is also proposing to allow averaging for units that elect to comply with the output-based standards. The DEP supports EPA's proposal to allow averaging for the owners or operators of units that elect to comply with the output-based standards. We also agree that these standards are equivalent to the input-based standards and promote energy efficiency.

Response: The EPA thanks the commenter for their support. See the response to comment EPA-HQ-OAR-2002-0056-3497-A1, excerpt 1 regarding output-based standards.

Commenter Name: Vickie Woods

Commenter Affiliation: Division of Air Quality, North Carolina Department of Environment and Natural Resources (NCDENR)

Document Control Number: EPA-HQ-OAR-2002-0058-3663-A2

Comment Excerpt Number: 5

Comment: Boiler efficiency calculation changes; EPA is proposing to add equations to allow for emissions averaging of output-based emission limits; averaging of output based limits was not previously included, although there is no technical reason why averaging of output based limits is inappropriate, given output-based limits are equivalent to input-based limits and promote energy efficiency.

NC DAQ supports the addition of output based emission limits to promote energy efficiency. We believe this is consistent with other sections of the subpart promoting and requiring energy efficiency measures.

Response: The EPA thanks the commenter for their support. See the response to comment EPA-HQ-OAR-2002-0056-3497-A1, excerpt 1 regarding output-based standards.

Commenter Name: David Gardiner

Commenter Affiliation: The Alliance for Industrial Efficiency

Document Control Number: EPA-HQ-OAR-2002-0058-3683-A2

Comment Excerpt Number: 4

Comment: We Commend EPA for Allowing Facilities to Simultaneously Adopt the Alternative Output-Based Compliance Standard and Average Emissions.

As elaborated above, the Alliance for Industrial Efficiency appreciates that the December Rule includes an output-based limitation option, which provides incentives for undertaking energy efficiency measures, including CHP and WHR, and that energy efficiency measures undertaken by the regulated entity can be credited toward compliance with the Rule. We also commend EPA for allowing emissions averaging within the Rule. As we noted in our Petition for Reconsideration, we were concerned about the apparent inability to combine both an output-based emissions standard and average emissions in the March 21, 2011 Rule. This limitation would force facilities to choose between two approaches that would support energy efficiency improvements.

We commend EPA for correcting this oversight in the re-proposed rule by allowing averaging for units that elect to comply with the output-based standards and for providing clear direction on how a facility may opt simultaneously for output-based emissions limitations and emissions averaging. As EPA notes in the re-proposed rule, "there is no technical reason why averaging of output-based limits is inappropriate."

Response: The EPA thanks the commenter for their support. See the response to comment EPA-HQ-OAR-2002-0056-3497-A1, excerpt 1 regarding output-based standards.

Commenter Name: Douglas A. McWilliams

Commenter Affiliation: American Municipal Power

Document Control Number: EPA-HQ-OAR-2002-0058-3685-A2

Comment Excerpt Number: 50

Comment: EPA has included numerous compliance demonstration alternatives in the Proposed Rule. AMP appreciates EPA's efforts to provide flexibility to the regulated community and supports EPA's inclusion of the following optional compliance alternatives:

Output-based emission limits tied to an emission credit scheme.

Response: The EPA thanks the commenter for their support. See the response to comment EPA-HQ-OAR-2002-0056-3497-A1, excerpt 1 regarding output-based standards.

14B. Emissions Averaging: Fuel Switching to Natural Gas

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 53

Comment: The emissions averaging provisions should allow owners or operators of a solid fuel or liquid fuel boiler to repower (convert) that boiler to natural gas (gas 1) within the averaging process.

EPA, in response to input from stakeholders, solicits comment on a suggested approach to allow an existing unit that is converted to natural gas to be included in an emissions average with other similar existing units.

76 Fed. Reg. 80617. CIBO strongly supports allowing companies to convert coal-fired units to cleaner-burning gas fuels without revoking that unit's eligibility for emissions averaging with remaining coal-fired units. For some companies, switching boilers from coal to cleaner-burning natural gas will offer the best environmental and business outcome because it will (1) result in greater emission reductions than what will be achieved through a standard end-of-stack control option and (2) it will allow facilities to implement a more cost-effective solution, conserving their capital for productive use in growth projects that may assist with the nation's economic recovery.

Moreover, this approach is fully consistent with both the express language of §112, which gives EPA considerable discretion in establishing source subcategories, and §112's underlying intent, which is to promote a "maximum degree of reduction in emissions of the hazardous air pollutants while "taking into consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements." 42 U.S.C.

§7412(d). Given EPA's support for emissions averaging between coal-fired units where operators elect to invest in capital-intensive pollution control technologies, EPA should support emissions averaging where operators select fuel switching as the most effective compliance strategy. While natural gas conversion is not available to every facility in every region, where it is technically and economically feasible, it offers the ability to reduce emissions far below the levels available with end-of-stack controls alone. 12

[Footnote 12: Here, it is important to distinguish between a mandatory fuel switching policy, as would occur if EPA presumed fuel switching to be a universal option for the purpose of setting MACT floor and beyond-the-floor standards, and voluntary fuel switching as a compliance strategy option. EPA has correctly recognized that it would be inappropriate to consider fuel switching as a universally-available factor for the purposes of setting MACT floor and beyond-the-floor standards. Specifically, EPA's 2010 proposed rule included a lengthy discussion of the pros and cons of fuel switching as a basis for setting floor and beyond the floor standard, ultimately dismissing the approach based on: 1) uncertainties regarding whether such a strategy would result in a net reduction of HAP emissions on a category-wide basis; 2) whether fuel switching would be technically achievable on a category wide basis; and 3) whether alternative fuels like natural gas would be reasonably available to all units within a category. See 75 Fed. Reg. 32,019 ("After considering these factors, we determined that fuel switching was not an appropriate control technology for purposes of determining the MACT floor level of control for any subcategory. This decision was based on the overall effect of fuel switching on HAP emissions, technical and design considerations discussed previously in this preamble, and concerns about fuel availability"). EPA's conclusion remains sound with respect to setting subcategory-wide standards. As numerous commenters have noted in the administrative record, the significant diversity of engineering, technological, and fuel-availability infrastructure available to units within any given subcategory make fuel substitution an impractical, if not arbitrary and capricious, basis for setting industry-wide floor or beyond-the-floor standards]

Response: EPA interprets section 112(d) to provide discretion to establish provisions that allow for emissions averaging, with certain restrictions to ensure that averaging does not violate the requirements of section 112. See 59 Fed. Reg., 19402, 19425 (Apr. 22, 1994). EPA first notes that section 112 does not require that the Agency allow emissions averaging in all MACT rules, but rather provides the discretion to do so where appropriate. In the boiler MACT, EPA has established an emissions averaging provision that is consistent with similar provisions in other MACT rules. It has been EPA's longstanding position that emissions averaging is not appropriate between sources that are not subject to the same emissions standard, such as coal-fired and natural gas-fired boilers, which are subject to different standards. While we understand that switching boilers from coal to cleaner-burning natural gas can offer environmental benefits, allowing emissions from natural gas boilers to be averaged with emissions from coal boilers when determining compliance would be inconsistent with this long-standing interpretation of EPA's discretion under section 112. See 62 Fed. Reg. 52384, 52388 (Oct. 7, 1997) and 77 Fed. Reg. 9304, 9384 (Feb. 16, 2012) (noting that emissions averaging in the MATS rule can only be used between EGUs in the same subcategory at a particular facility). In addition, such an approach would allow averaging among multiple sources, which would again be inconsistent with EPA's long-standing interpretation of its discretion to establish averaging provisions under section 112. *Id.* (referring to averaging within the same facility). The affected source as defined in the Boiler MACT is the collection of boilers and process heaters at a single facility within the

same subcategory. Each subcategory has its own emissions standards. As explained in the preamble to EPA's earlier establishment of emissions averaging programs, if averaging were permitted between units subject to different standards (such as coal-fired and natural gas-fired boilers), it is likely that one of the sources' emissions would violate the standard that applies to it. See 59 Fed. Reg. at 19427. The commenters provide no explanation as to how the long-standing restrictions that EPA has applied to averaging provisions will be met if EPA allows averaging between coal-fired boilers and boilers converted to combust natural gas. For these reasons, EPA is not revising the proposed rule to allow such averaging.

Commenter Name: Jessica Bridges

Commenter Affiliation: United States Clean Heat & Power Association (USCHPA)

Document Control Number: EPA-HQ-OAR-2002-0058-3501-A1

Comment Excerpt Number: 21

Comment: We are supportive of the goal to create flexibility that averaging could bring to fuel switching situations.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 53.

Commenter Name: Michael L. Krancer

Commenter Affiliation: Pennsylvania Department of Environmental Protection (DEP)

Document Control Number: EPA-HQ-OAR-2002-0058-3507-A1

Comment Excerpt Number: 21

Comment: The EPA is soliciting comment on the potential benefit of switching to cleaner fuels such as natural gas, which are environmentally beneficial, for purposes of averaging emissions with units of the original unit design.

The DEP believes that units that are retrofitted to switch to natural gas should be allowed to average emissions with units of the original unit design; this approach is environmentally beneficial. In addition, the DEP agrees with the petitioners that allowing averaging across subcategories when fuel-switching has been used to achieve compliance and would encourage fuel-switching to cleaner fuels.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 53.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 139

Comment: *THE EMISSIONS AVERAGING PROVISIONS SHOULD ALLOW OWNERS OR OPERATORS OF A SOLID FUEL OR LIQUID FUEL BOILER TO REPOWER (CONVERT) THAT BOILER TO NATURAL GAS (GAS 1) WITHIN THE AVERAGING PROCESS.*

On page 80617 of the Reconsidered Proposal, EPA, in response to input from stakeholders, solicits comment on a suggested approach to allow an existing unit that is converted to natural

gas to be included in an emissions average with other similar existing units. EPA's request for comment is shown below: *Stakeholders asked the EPA to consider, for units that are retrofitted to switch to natural gas as a compliance option, allowing those units to average emissions with units of the original unit design. These parties suggested that continuing to allow such averaging would be consistent with EPA's general approach of specifying emission standards for affected facilities, but otherwise allowing the facilities to comply however they see fit. They also pointed out that this may allow for more effective controls overall. For example, they suggested that without allowing for averaging of units that switch to cleaner fuels as a compliance option, natural gas conversion is a less attractive option than if such averaging was allowed, because a facility would not have the ability to offset emissions using that unit. In this case, these stakeholders believe that installing controls that result in fewer emissions reductions than switching to natural gas may be a perverse outcome. They suggested that continuing to allow averaging across subcategories in cases where fuel switching has been used to achieve compliance would instead encourage fuel switching to cleaner fuels, which is environmentally beneficial. The EPA is requesting comment on the potential benefit of this suggested approach, and how such an approach could be justified and incorporated into the rule.*

ACC strongly supports allowing companies to convert coal-fired units to cleaner-burning gas fuels without revoking that unit's eligibility for emissions averaging with remaining coal-fired units. For some companies, switching boilers from coal to cleaner-burning natural gas will offer the best environmental and business outcome because it will (1) result in greater emission reductions than what will be achieved through a standard end-of-stack control option and (2) it will allow facilities to implement a more cost-effective solution, conserving their capital for productive use in growth projects that may assist with the nation's economic recovery.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 53.

Commenter Name: Robin Mills Ridgway

Commenter Affiliation: Purdue University

Document Control Number: EPA-HQ-OAR-2002-0058-3668-A2

Comment Excerpt Number: 1

Comment: Purdue thanks EPA for continuing to incorporate emissions averaging into the rule. In addition, Purdue supports the proposal discussed in the preamble to allow units switched to natural gas for Boiler MACT compliance to be used in emissions averaging with other boilers of the same category as the fuel switched boiler was prior to Boiler MACT compliance. To determine the emission value of the fuels switched unit to be used in the averaging equation, Purdue suggests the use of the method detection limits for the averaged pollutants.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 53.

Commenter Name: Steve Gossett

Commenter Affiliation: Eastman Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3669-A2

Comment Excerpt Number: 36

Comment: M.1 Other Issues Open for Comment: Emissions Averaging for Repowered Boilers

Comment Summary: The emissions averaging provisions should allow owners or operators of a solid fuel or liquid fuel boiler to repower (convert) that boiler to natural gas (gas 1) within the averaging process.

Eastman strongly supports allowing companies to convert coal-fired units to cleaner-burning gas fuels without revoking that unit's eligibility for emissions averaging with remaining coal-fired units. For some companies, switching boilers from coal to cleaner-burning natural gas will offer the best environmental and business outcome because it will (1) result in greater emission reductions than what will be achieved through a standard end-of-stack control option and (2) it will allow facilities to implement a more cost-effective solution, conserving their capital for productive use in growth projects that may assist with the nation's economic recovery.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 53.

Commenter Name: Steve Gossett

Commenter Affiliation: Eastman Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3669-A2

Comment Excerpt Number: 37

Comment: This approach is fully consistent with both the express language of section 112, which gives EPA considerable discretion in establishing source subcategories, and section 112's underlying intent, which is to promote a "maximum degree of reduction in emissions of the hazardous air pollutants while "taking into consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements." 42 U.S.C. §7412(d). Given EPA's support for emissions averaging between coal-fired units where operators elect to invest in capital-intensive pollution control technologies, EPA should support emissions averaging where operators select fuel switching as the most effective compliance strategy. While natural gas conversion is not available to every facility in every region, where it is technically and economically feasible, it offers the ability to reduce emissions far below the levels available with end-of-stack controls alone. 1

[Footnote 1: Here, it is important to distinguish between a mandatory fuel switching policy, as would occur if EPA presumed fuel switching to be a universal option for the purpose of setting MACT floor and beyond-the-floor standards, and voluntary fuel switching as a compliance strategy option. EPA has correctly recognized that it would be inappropriate to consider fuel switching as a universally-available factor for the purposes of setting MACT floor and beyond-the-floor standards. Specifically, EPA's 2010 proposed rule included a lengthy discussion of the pros and cons of fuel switching as a basis for setting floor and beyond the floor standard, ultimately dismissing the approach based on: 1) uncertainties regarding whether such a strategy would result in a net reduction of HAP emissions on a category-wide basis; 2) whether fuel switching would be technically achievable on a category wide basis; and 3) whether alternative fuels like natural gas would be reasonably available to all units within a category. See 75 Fed. Reg. 32,019 ("After considering these factors, we determined that fuel switching was not an appropriate control technology for purposes of determining the MACT floor level of control for any subcategory. This decision was based on the overall effect of fuel switching on HAP emissions, technical and design considerations discussed previously in this preamble, and concerns about fuel availability"). EPA's conclusion remains sound with respect to setting

subcategory-wide standards. As numerous commenters have noted in the administrative record, the significant diversity of engineering, technological, and fuel-availability infrastructure available to units within any given subcategory make fuel substitution an impractical, if not arbitrary and capricious, basis for setting industry-wide floor or beyond-the-floor standards.]

Response: See the response to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 53.

Commenter Name: Steve Gossett

Commenter Affiliation: Eastman Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3669-A2

Comment Excerpt Number: 52

Comment: Sec. 63.7522 Can I use emissions averaging to comply with this subpart?

(a) As an alternative to meeting the requirements of §63.7500 for particulate matter, hydrogen chloride, or mercury on a boiler or process heater-specific basis, if you have more than one existing boiler or process heater in any subcategory subject to a numerical emission standard in Table 2 to this subpart located at your facility, you may demonstrate compliance by emissions averaging if you satisfy the requirements in paragraphs (b) through (m).

(b) You may not include new boilers or process heaters in an emissions average.

(c) For purposes of this section, an existing boiler or process heater that is part of any subcategory listed in Table 2 to this subpart as of December 23, 2011 may be included in an emissions average group with other existing units within these subcategories even if the boiler or process heater is converted to be part of the *unit designed to burn gas 1 subcategory* after December 23, 2011. Such a converted boiler or process heater shall not be required to conduct subsequent annual performance tests as required by §63.7515(b). Such a unit shall be subject to the other applicable requirements in this subpart for units designed to burn gas 1.

(d) For a group of two or more existing boilers or process heaters that each vent to a separate stack, you may average particulate matter, hydrogen chloride, or mercury emissions among existing units to demonstrate compliance with the limits in Table 2 to this subpart as specified in paragraph (b)(1) through (3) of this section, if you satisfy the requirements in paragraphs (e) through (g) of this section.

(e) For each existing boiler or process heater in the averaging group, the emission rate achieved during the initial compliance test for the HAP being averaged must not exceed the emission level that was being achieved on [DATE 60 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE Federal Register] or the control technology employed during the initial compliance test must not be less effective for the

HAP being averaged than the control technology employed on [DATE 60 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE Federal Register].

(f) For all boilers or process heaters included in an emissions average, the owner or operator shall:

(1) Calculate and record monthly debits for all boilers and process heaters that are controlled to a level less stringent than the applicable emission standard from Table 2 to this subpart. Equations in paragraph (g) of this section shall be used to calculate debits.

(2) Calculate and record monthly credits for all boilers and process heaters that are over-controlled to compensate for the debits. Equations in paragraph (h) of this section shall be used to calculate credits.

(3) After 12 complete calendar months of operation, and at the end of each subsequent calendar month, following the compliance date specified in §63.7495, demonstrate that the 12-month moving total credits calculated according to paragraph (h) of this section are greater than or equal to debits calculated for the same 12-month moving period according to paragraph (g) of this section.

(i) The owner or operator may choose to include more than the required number of credit-generating boilers and process heaters in an average in order to increase the likelihood of being in compliance.

(ii) The initial demonstration in the implementation plan for emissions averaging required in § 63.7522(i) that credit-generating boilers and process heaters will be capable of generating sufficient credits to offset the debits from the debit-generating boilers and process heaters must be made under representative operating conditions. After the compliance date, actual operating data will be used for all debit and credit calculations.

(4) Record and report 12-month moving credits and debits in the compliance reports required in §63.7550(c) of this subpart.

(g) Debits are calculated as follows:

(1) If you are complying with emission limits on a heat input basis, debits are generated by the difference between the actual emissions from a boiler or process heater that is uncontrolled or is controlled to a level less stringent than the applicable emission standard from Table 2 to this subpart, and the emissions allowed for the boiler or process heater by the applicable emission standard from Table 2 to this subpart. Debits shall be calculated as follows:

The overall equation for calculating source-wide debits is:

n

$$\text{Debits} = \sum_{i=1}^n (E_r - E_l) H_b \text{ Eq 1a}$$

i=1

Where:

E_r = Emission rate (as determined during the most recent compliance demonstration or from continuous emissions monitoring systems) of particulate matter, hydrogen chloride, or mercury from unit, i , in units of pounds per million Btu of heat input. Determine the emission rate for particulate matter, hydrogen chloride, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for hydrogen chloride or mercury using the applicable equation

in §63.7530(c). Alternative equations and sampling and analytical plans for determining emission rate by fuel analysis may be proposed to and approved by the applicable delegated authority as part of the implementation plan for emissions averaging required in to §63.7522(i). If you are taking credit for energy conservation measures from a unit according to §63.7533, use the adjusted emission level for that unit, E_{adj} , determined according to §63.7533 for that unit.

E_l = Emission limit from Table 2 to this subpart for unit, i , in units of pounds per million Btu of heat input.

H_b = The heat input for that calendar month to unit, i , in units of million Btu. If you are not capable of monitoring heat input, use the following equation to determine H_b :

$$H_b = S_a \times C_{fi}$$

Where:

S_a = Actual steam generation for that calendar month, by boiler or process heater, i , in units of pounds.

C_{fi} = Conversion factor, as calculated during the most recent compliance test, in units of million Btu of heat input per pounds of steam generated for boiler or process heater, i .

n = number of units participating in the emissions averaging option.

(2) If you are complying with emission limits on steam generation (output) basis, debits are generated by the difference between the actual emissions from a boiler or process heater that is uncontrolled or is controlled to a level less stringent than the applicable emission standard from Table 2 to this subpart, and the emissions allowed for the boiler or process heater by the applicable emission standard from Table 2 to this subpart. Debits shall be calculated as follows:

The overall equation for calculating source-wide debits is:

n

$$\text{Debits} = \sum_{i=1}^n (E_r - E_l) \text{ So Eq 1b}$$

$i=1$

Where:

E_r = Emission rate (as determined during the most recent compliance demonstration or from continuous emissions monitoring systems) of particulate matter, hydrogen chloride, or mercury from unit, i , in units of pounds per million Btu of steam output. Determine the emission rate for particulate matter, hydrogen chloride, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for hydrogen chloride or mercury using the applicable equation in §63.7530(c). Alternative equations and sampling and analytical plans for determining emission rate by fuel analysis may be proposed to and approved by the applicable delegated authority as part of the implementation plan for emissions averaging required in to §63.7522(i). If you are taking credit for energy conservation measures from a unit according §63.7533, use the adjusted emission level for that unit, E_{adj} , determined according to §63.7533 for that unit.

El= Emission limit from Table 2 to this subpart for unit, i, in units of pounds per million Btu of heat input.

So = Maximum steam output capacity of unit, I, in units of million Btu per hour, as defined in §63.7575.

n = number of units participating in the emissions averaging option.

(h) Credits are calculated as follows:

(1) If you are complying with emission limits on a heat input basis, credits are generated by the difference between the emissions that are allowed for boiler or process heater by the applicable emission standard from Table 2 to this subpart and the actual emissions from a boiler or process heater that is uncontrolled or is controlled to a level less stringent than the applicable emission standard from Table 2 to this subpart. Credits shall be calculated as follows:

The overall equation for calculating source-wide credits is:

n

Debits = $D \sum_{i=1} (El - Er) H_b$ Eq 2a

i=1

Where:

D= Discount factor=0.9 for all credit generating boilers or process heaters.

El= Emission limit from Table 2 to this subpart for unit, i, in units of pounds per million Btu of heat input.

Er = Emission rate (as determined during the most recent compliance demonstration or from continuous emissions monitoring systems) of particulate matter, hydrogen chloride, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for particulate matter, hydrogen chloride, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for hydrogen chloride or mercury using the applicable equation in §63.7530(c). Alternative equations and sampling and analytical plans for determining emission rate by fuel analysis may be proposed to and approved by the applicable delegated authority as part of the implementation plan for emissions averaging required in to §63.7522(i). If you are taking credit for energy conservation measures from a unit according §63.7533, use the adjusted emission level for that unit, Eadj, determined according to §63.7533 for that unit.

Hb = The heat input for that calendar month to unit, i, in units of million Btu. If you are not capable of monitoring heat input, use the following equation to determine Hb:

$H_b = S_a \times C_f$

Where:

Sa = Actual steam generation for that calendar month, by boiler or process heater, I, in units of pounds.

C_{fi} = Conversion factor, as calculated during the most recent compliance test, in units of million Btu of heat input per pounds of steam generated for boiler or process heater, i.

n = number of units participating in the emissions averaging option.

(2) If you are complying with emission limits on a steam generation (output) basis, credits are generated by the difference between the emissions that are allowed for boiler or process heater by the applicable emission standard from Table 2 to this subpart and the actual emissions from a boiler or process heater that is uncontrolled or is controlled to a level less stringent than the applicable emission standard from Table 2 to this subpart. Credits shall be calculated as follows:

The overall equation for calculating source-wide credits is:

n

$$\text{Debits} = D \sum_{i=1} (E_i - E_r) S_{o_i} \quad \text{Eq 2b}$$

i=1

Where:

D= Discount factor=0.9 for all credit generating boilers or process heaters.

E_i= Emission limit from Table 2 to this subpart for unit, i, in units of pounds per million Btu of heat input.

E_r = Emission rate (as determined during the most recent compliance demonstration or from continuous emissions monitoring systems) of particulate matter, hydrogen chloride, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for particulate matter, hydrogen chloride, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for hydrogen chloride or mercury using the applicable equation in §63.7530(c). Alternative equations and sampling and analytical plans for determining emission rate by fuel analysis may be proposed to and approved by the applicable delegated authority as part of the implementation plan for emissions averaging required in to §63.7522(i). If you are taking credit for energy conservation measures from a unit according to Sec. 63.7533, use the adjusted emission level for that unit, E_{adj}, determined according to Sec. 63.7533 for that unit.

S_o = Maximum steam output capacity of unit, I, in units of million Btu per hour, as defined in §63.7575.

n = number of units participating in the emissions averaging option.

(i) You must develop, and submit to the applicable delegated authority for review and approval, an implementation plan for emission averaging according to the following procedures and requirements in paragraphs (i)(1) through (4) of this section.

(1) You must submit the implementation plan no later than 180 days before the date that the facility intends to demonstrate compliance using the emission averaging option.

(2) You must include the information contained in paragraphs (i)(2)(i) through (viii) of this section in your implementation plan for all emission sources included in an emissions average:

(i) The identification of all existing boilers and process heaters in the averaging group, including for each either the applicable HAP emission level or the control technology installed as of [DATE 60 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE Federal Register] and the date on which you are requesting emission averaging to commence;

(ii) The process parameter (heat input or steam generated) that will be monitored for each averaging group;

(iii) The specific control technology or pollution prevention measure to be used for each emission boiler or process heater in the averaging group and the date of its installation or application. If the pollution prevention measure reduces or eliminates emissions from multiple boilers or process heaters, the owner or operator must identify each boiler or process heater;

(iv) The test plan for the measurement of particulate matter, hydrogen chloride, or mercury emissions in accordance with the requirements in Sec. 63.7520;

(v) The operating parameters to be monitored for each control system or device consistent with §63.7500 and Table 4, and a description of how the operating limits will be determined;

(vi) If you request to monitor an alternative operating parameter pursuant to §63.7525, you must also include:

(A) A description of the parameter(s) to be monitored and an explanation of the criteria used to select the parameter(s); and

(B) A description of the methods and procedures that will be used to demonstrate that the parameter indicates proper operation of the control device; the frequency and content of monitoring, reporting, and recordkeeping requirements; and a demonstration, to the satisfaction of the applicable delegated authority, that the proposed monitoring frequency is sufficient to represent control device operating conditions; and

(vii) A demonstration that compliance with each of the applicable emission limit(s) will be achieved under representative operating load conditions. Following each compliance demonstration and until the next compliance demonstration, you must comply with the operating limit for operating load conditions specified in Table 4 to this subpart.

(viii) Any requested alternative equation and sampling and analytical plans for determining emission rate by fuel analysis for use in calculating credits and debits pursuant to §63.7522(g) and (h).

(3) The delegated authority shall review and approve or disapprove the plan according to the following criteria:

(i) Whether the content of the plan includes all of the information specified in paragraph (i)(2) of this section; and

(ii) Whether the plan presents sufficient information to determine that compliance will be achieved and maintained.

(4) The applicable delegated authority shall not approve an emission averaging implementation plan containing any averaging between emissions of differing pollutants.

(j) For a group of two or more existing affected units, each of which vents through a single common stack, you may average particulate matter, hydrogen chloride, or mercury emissions to demonstrate compliance with the limits for that pollutant in Table 2 to this subpart if you satisfy the requirements in paragraph (k) or (l) of this section.

(k) For a group of two or more existing units in the same subcategory, each of which vents through a common emissions control system to a common stack, that does not receive emissions from units in other subcategories or categories, you may treat such averaging group as a single existing unit for purposes of this subpart and comply with the requirements of this subpart as if the group were a single unit.

(l) For all other groups of units subject to the common stack requirements of paragraph (j) of this section, including situations where the exhaust of affected units are each individually controlled and then sent to a common stack, the owner or operator may elect to:

(1) Conduct performance tests according to procedures specified in Sec. 63.7520 in the common stack if affected units from other subcategories vent to the common stack. The emission limit (El in Equations 1a, 1b, 2a, and 2b) for the group is determined by the use of Equation 3 of this section.

$$N \text{ n El} = \Sigma (\text{Eli} \times \text{Hi}) \div \Sigma \text{Hi} \text{ Eq. 3}$$

i=1 i=1

Where:

El = HAP emission limit, pounds per million British thermal units (lb/MMBtu).

Eli = Appropriate emission limit from Table 2 to this subpart for unit i, in units of lb/MMBtu.

Hi = Heat input from unit i, MMBtu.

(2) Conduct performance tests according to procedures specified §63.7520 in the common stack. If affected units and non-affected units vent to the common stack, the non-affected units must be shut down or vented to a different stack during the performance test unless the facility determines to demonstrate compliance with the non-affected units venting to the stack; and

(3) Meet the applicable operating limit specified §63.7540 and Table 8 to this subpart for each emissions control system (except that, if each unit venting to the common stack has an applicable opacity operating limit, then a single continuous opacity monitoring system may be located in the common stack instead of in each duct to the common stack).

(m) The common stack of a group of two or more existing boilers or process heaters in the same subcategory subject to paragraph (j) of this section may be treated as a separate stack for purposes of

paragraph (f) of this section and included in an emissions averaging group subject to paragraph (f) of this section.

§63.7541 How do I demonstrate continuous compliance under the emissions averaging provision?

(a) Following the compliance date, the owner or operator must demonstrate compliance with this subpart on a continuous basis by meeting the requirements of paragraphs (a)(1) through (5) of this section.

(1) For each calendar month, comply with requirements specified in §63.7522(f) to demonstrate that 12-month moving total credits calculated according to paragraph (h) of this section are greater than or equal to debits calculated for the same 12-month moving period.

(2) You must maintain the applicable opacity limit according to paragraphs (a)(2)(i) and (ii) of this section.

(i) For each existing unit participating in the emissions averaging option that is equipped with a dry control system and not vented to a common stack, maintain opacity at or below the applicable limit.

(ii) For each group of units participating in the emissions averaging option where each unit in the group is equipped with a dry control system and vented to a common stack that does not receive emissions from non-affected units, maintain opacity at or below the applicable limit at the common stack.

(3) For each existing unit participating in the emissions averaging option that is equipped with a wet scrubber, maintain the 30-day rolling average parameter values at or below the operating limits established during the most recent performance test.

(4) For each existing unit participating in the emissions averaging option that has an approved alternative operating plan, maintain the 30-day rolling average parameter values at or below the operating limits established in the most recent performance test.

(5) For each existing unit participating in the emissions averaging option venting to a common stack configuration containing affected units from other subcategories, maintain the appropriate operating limit for each unit as specified in Table 4 to this subpart that applies.

(b) Any instance where the owner or operator fails to comply with the continuous monitoring requirements in paragraphs (a)(1) through (5) of this section is a deviation.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 53.

Commenter Name: Pamela Lacey

Commenter Affiliation: American Gas Association (AGA)

Document Control Number: EPA-HQ-OAR-2002-0058-3672-A2

Comment Excerpt Number: 7

Comment: As explained in comments filed in this docket by the Business Council for Sustainable Energy (BCSE), the proposed rule would encourage and facilitate conversions from coal or oil to natural gas and would encourage the use of energy efficient combined heat and power (CHP). AGA is a member of BCSE and we support the BCSE comments.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 53.

Commenter Name: Robert Ellerhorst

Commenter Affiliation: Michigan State University

Document Control Number: EPA-HQ-OAR-2002-0058-3674-A2

Comment Excerpt Number: 8

Comment: U.S. EPA is requesting comments to allow emissions from retrofitted units that switched to cleaner fuels (i.e. natural gas) to be averaged with emissions from units that remain of the original unit design (i.e. solid fuel, oil-fired) that operate at the same facility. MSU believes that this type of emissions averaging is a beneficial option for existing sources for pollutants such as mercury, hydrogen chloride and particulate matter. Without allowing for the averaging of units that switch to cleaner fuels with other existing units at the campus, the use of fuel switching as a compliance option becomes expensive and burdensome as it would not be possible to offset emissions using the converted unit. However, allowing units where fuel switching has occurred to be averaged across subcategories would encourage fuel switching on older, higher emitting units. Therefore, as stated above, MSU is in support of allowing emissions averaging across subcategories in situations where fuel switching is involved.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 53.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 54

Comment: EPA's policy should not discourage or penalize companies that adopt fuel switching as a voluntary compliance strategy. Yet, EPA's proposed rule does just that. Currently, the rule would restrict emissions averaging to boilers in the same subcategory (*see* §63.7522(b)). Under our understanding of the proposed rule, a solid or liquid fuel boiler converted to natural gas could not be part of an emissions average with other solid or liquid fuel boilers at a site because that boiler would no longer belong to the same subcategory of boilers with which it would be averaged. This situation is further complicated by EPA's proposal to subcategorize solid and liquid fuel boilers even more narrowly, a step that will reduce the opportunities for averaging and decreases compliance options with little environmental benefit.

Such bureaucratic limits and distinctions put form over substance and are nonsensical from both a legal and policy perspective. EPA's mandate under §112 is to promote a maximum degree of reduction in emissions of the hazardous air pollutants "taking into consideration compliance

costs, and any non-air quality health and environmental impacts and energy requirements." EPA should not mandate which technologies companies select to lower their net emissions from EPA existing sources, particularly where EPA's policy results in *less* pollution control. EPA should eliminate the restriction on averaging across subcategories and focus on reducing emissions.

Response: We disagree that the rule discourages or penalizes companies that adopt fuel switching to natural gas as a compliance strategy. The final rule establishes a work practice standard for natural gas boilers instead of numeric emission limits, as explained in the record for the March 2011 final rule. The commenter further claims that EPA has "further complicated" the situation by proposing additional subcategories, but does not allege that or explain how it believes the additional subcategories are unwarranted. As explained in [cite to earlier response], EPA's long-standing position when establishing emissions averaging in MACT rules has been that averaging between units in different subcategories subject to different emissions standards is not appropriate.

Commenter Name: Steve Gossett

Commenter Affiliation: Eastman Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3669-A2

Comment Excerpt Number: 38

Comment: EPA's policy should not discourage or penalize companies that adopt fuel switching as a voluntary compliance strategy. Yet, EPA's proposed rule does just that. Currently, the rule would restrict emissions averaging to boilers in the same subcategory (*see* §63.7522(b)). Under Eastman's understanding of the proposed rule, a solid or liquid fuel boiler converted to natural gas could not be part of an emissions average with other solid or liquid fuel boilers at a site because that boiler would no longer belong to the same subcategory of boilers with which it would be averaged. This situation is further complicated by EPA's proposal to subcategorize solid and liquid fuel boilers even more narrowly (*see* comments elsewhere), a step that will reduce the opportunities for averaging and decreases compliance options with little environmental benefit.

Such bureaucratic limits and distinctions put form over substance and are nonsensical from both a legal and policy perspective. EPA's mandate under section 112 is to promote a maximum degree of reduction in emissions of the hazardous air pollutants "taking into consideration compliance costs, and any non-air quality health and environmental impacts and energy requirements." EPA should not mandate which technologies companies select to lower their net emissions from existing sources, particularly where EPA's policy results in *less* pollution control. EPA should eliminate the restriction on averaging across subcategories and focus on reducing emissions.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 54.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 55

Comment: Alternatively, EPA can eliminate the unintended impact of its cross-subcategory policy by using its considerable statutory authority to develop subcategories that allow fuel switching and other innovative emissions reduction strategies. As the Agency itself has acknowledged, EPA has broad discretion to establish such categories and subcategories as it deems appropriate, *Id.* §7412(c)(5), and to distinguish among classes, types, and sizes of sources within a category or subcategory in establishing standards. *Id.* §7412(d)(1). There is nothing in the statute, or in ensuing case law interpreting EPA's discretion, that would prevent the Agency from setting categories and subcategories based on their operational characteristics at a specific point in time. *See, e.g.,* Utility MACT at 411; *Northeast Maryland Waste Disposal Authority v. EPA*, 358 F.3d 936, (D.C. Cir. 2004) ("[The Clean Air Act] gives the EPA broad discretion to differentiate among units in a category. . . , provided the EPA indicated why such a subcategorization was appropriate."); *Davis County Solid Waste Mgmt. v. EPA*, 101 F.3d 1395, 1411 (D.C. Cir. 1996) ("Class is an ambiguous term. It is not defined in the Clean Air Act, and the dictionary definition -- "a group, set, or kind marked by common attributes" -- could hardly be more flexible.").

Using this flexibility, EPA should revise the subcategories used for the MACT rule to establish that, for purposes of emissions averaging, an existing unit belongs to the subcategory within which it fits as of the rule proposal date (December 23, 2011). Suggested regulatory language is shown below:¹³

§63.7522(a): As an alternative to meeting the requirements of 63.7500 for particulate matter, hydrogen chloride, or mercury on a boiler or process heater-specific basis, if you have more than one existing boiler or process heater in any subcategory, you may demonstrate compliance by emissions averaging, if your averaged emissions are not more than 90 percent of the applicable emission limit, according to the procedures of this section. For purposes of this section, an existing boiler or process heater that is part of any subcategory listed in Table 2 to this subpart as of December 23, 2011 may be included in an emissions average group with other existing units within these subcategories even if the boiler or process heater is converted to be part of the unit designed to burn gas 1 subcategory after December 23, 2011. Such a converted boiler or process heater shall not be required to conduct subsequent annual performance tests as required by §63.7515(b) but such a unit shall be subject to the other applicable requirements in this subpart for units designed to burn gas 1. You may not include new boilers or process heaters in an emissions average.

[Footnote 13: As reflected in the recommended language, an existing natural gas unit should not be able to convert to a solid fuel boiler (burning at least 10 percent solid fuel) and using this as a strategy for compliance.]

Response: As the commenter notes, EPA has broad discretion to decide whether to subcategorize sources within a source category based on differences in class, type, or size pursuant to CAA section 112(d)(1). The EPA maintains that, normally, any basis for subcategorization must be related to an effect on HAP emissions that is due to the difference in class, type, or size of the units. *See* 76 Fed. Reg at 25036-37. If sources can achieve the same level of emissions reductions notwithstanding such differences, the purposes of section 112 are better served by requiring a similar level of control for all units in the category or subcategory. *See* *Lignite Energy Council v. EPA*, 198 F.3d 930, 933 (D.C. Cir. 1999). In this case, the emissions from a converted (to natural gas) coal-fired boiler will not be different than those from

a boiler designed for and originally operated using natural gas combustion, and the commenter has not provided any information to demonstrate otherwise. Therefore, the EPA disagrees with the commenter's suggestion that the Agency should exercise its discretion to establish a separate subcategory for units converted to natural gas, as compared to those that first operated using natural gas.

Commenter Name: Steve Gossett

Commenter Affiliation: Eastman Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3669-A2

Comment Excerpt Number: 39

Comment: Alternatively, EPA can eliminate the unintended impact of its cross-subcategory policy by using its considerable statutory authority to develop subcategories that allow fuel switching and other innovative emissions reduction strategies. As the Agency itself has acknowledged, EPA has broad discretion to establish such categories and subcategories as it deems appropriate, *Id.* §7412(c)(5), and to distinguish among classes, types, and sizes of sources within a category or subcategory in establishing standards. *Id.* §7412(d)(1). There is nothing in the statute, or in ensuing case law interpreting EPA's discretion, that would prevent the Agency from setting categories and subcategories based on their operational characteristics at a specific point in time. *See, e.g.,* Utility MACT at 411; *Northeast Maryland Waste Disposal Authority v. EPA*, 358 F.3d 936, (D.C. Cir. 2004) ("[The Clean Air Act] gives the EPA broad discretion to differentiate among units in a category. . . , provided the EPA indicated why such a subcategorization was appropriate."); *Davis County Solid Waste Mgmt. v. EPA*, 101 F.3d 1395, 1411 (D.C. Cir. 1996) ("Class is an ambiguous term. It is not defined in the Clean Air Act, and the dictionary definition -- "a group, set, or kind marked by common attributes" -- could hardly be more flexible.").

Using this flexibility, EPA should revise the subcategories used for the MACT rule to establish that, for purposes of emissions averaging, an existing unit belongs to the subcategory within which it fits as of the rule proposal date (December 23, 2011). Suggested regulatory language is shown below:²

§63.7522(a): As an alternative to meeting the requirements of 63.7500 for particulate matter, hydrogen chloride, or mercury on a boiler or process heater-specific basis, if you have more than one existing boiler or process heater in any subcategory, you may demonstrate compliance by emissions averaging, if your averaged emissions are not more than 90 percent of the applicable emission limit, according to the procedures of this section. For purposes of this section, an existing boiler or process heater that is part of any *subcategory listed in Table 2 to this subpart* as of December 23, 2011 may be included in an emissions average group with other existing units within these subcategories even if the boiler or process heater is converted to be part of the *unit designed to burn gas 1 subcategory* after December 23, 2011. Such a converted boiler or process heater shall not be required to conduct subsequent annual performance tests as required by §63.7515(b) but such a unit shall be subject to the other applicable requirements in this subpart for units designed to burn gas 1. You may not include new boilers or process heaters in an emissions average.

[Footnote 2: As reflected in the recommended language, an existing natural gas unit should not be able to convert to a solid fuel boiler (burning at least 10 percent solid fuel) and using this as a strategy for compliance.]

Response: See the response to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 55.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 56

Comment: The Agency has expressed its concern that it may lack authority to allow averaging across subcategories or that such allowance would be inconsistent with its policy in providing emissions averaging options in other rules. However, as discussed in the preamble to the HON (Hazardous Organic NESHAP for the Synthetic Organic Chemicals Manufacturing Industry (SOCMI) (Federal Register, April 22, 1994, starting on page 19425)), the rule EPA cites as precedent for emissions averaging, EPA has itself acknowledged its wide discretion to define "source" broadly. Indeed, in the case of the HON, EPA defined the source category to include all emission points relating to SOCMI production at a facility – a range of emission points and technologies far more diverse than the differences between coal-fired and converted coal-to-gas boilers. The HON allows all emission points that have numerical emission standards to participate in an emissions average. Process vents, storage vessels, transfer rack, and wastewater streams are all allowed in the emissions average and they all have differing emission standards. Only equipment leaks, which have no defined allowable emission level, are excluded.

To be clear, CIBO proposes that units sub-categorized as solid or liquid fuel boilers or process heaters on December 23, 2011, and thereafter converted to fire gas 1 fuels, will remain sub-categorized as solid or liquid fuel boilers or process heaters, only for purposes of emissions averaging. While the conversion of a solid or liquid fuel boiler or process heater to gas 1 will not change the unit's sub-categorization for purposes of emissions averaging, the boiler or process heater would be required to comply with work practice standards and other recordkeeping and reporting requirements applicable to gas 1 boilers or process heaters.

Response: We specifically disagree that broader averaging is consistent with the statute as explained in the preamble to the HON NESHAP. Moreover, the commenter ignores the fact that the HON specifically declined to allow averaging between sources subject to different emissions standards, as are coal-fired and natural gas-fired boilers. See 62 Fed. Reg. at 52388. Moreover, as EPA explained in the HON: "The fundamental problem with the broader averaging approach, beyond sources in the same subcategory, is that it allows averaging among multiple sources. The HON has defined the affected source, for the purposes of that standard, as the collection of SOGMI emission points within a major source. Many major sources containing such points will also contain other points not covered by the HON standard but to be covered by later, different MACT standards. Each of these standards will have a separate floor, and the statute requires that each standard be no less stringent than its floor. *If averaging were allowed between sources covered by two separate standards, it is likely that one of the sources involved in the average would be emitting HAP's at a level that violates the standard applicable to it.* Thus, averaging

between multiple sources in different subcategories is not legally defensible.” 59 Fed. Reg. at 19427 (emphasis added).

The affected source under the Boiler MACT is the collection of all existing boilers and process heaters within the same subcategory, and each subcategory within the Boiler MACT has separate standards based on separate floors, including coal-fired and natural gas-fired boilers. Consistent with EPA’s long-standing position, emissions averaging is not allowed between different affected sources (i.e., subcategories). Moreover, the commenter emphasizes that, while it believes that boilers converted to natural gas should be treated as being in the same subcategory as before such conversion, the converted boiler should be in a separate subcategory for the purpose of setting MACT standards – and further, that the appropriate standard for natural gas-fired boilers (including boilers converted to natural gas) is the work practice standard that EPA has adopted. EPA believes the commenter’s position contains an internal inconsistency that cannot be reconciled. Specifically, the commenter provides no basis for establishing a separate subcategory based on differences in class, type, or size for one purpose (standard-setting) while not doing so for another (emissions averaging), and does not explain why a different subcategorization approach for different purposes for the same units is not arbitrary.

Commenter Name: Steve Gossett

Commenter Affiliation: Eastman Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3669-A2

Comment Excerpt Number: 41

Comment: To be clear, Eastman proposes that units sub-categorized as solid or liquid fuel boilers or process heaters on December 23, 2011, and thereafter converted to fire gas 1 fuels, will remain sub-categorized as solid or liquid fuel boilers or process heaters, only for purposes of emissions averaging. While the conversion of a solid or liquid fuel boiler or process heater to gas 1 will not change the unit’s sub-categorization for purposes of emissions averaging, the boiler or process heater would be required to comply with work practice standards and other recordkeeping and reporting requirements applicable to gas 1 boilers or process heaters.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 56.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 57

Comment: EPA’s decision to propose work practice standards for gas 1 units is based on its determination that the application of measurement technology to this particular class of sources is not practicable due to technological and economic limitations (*see* §112(h)(2)(B) of the Act). This decision was driven, in part, by the extremely low numerical emission limits that EPA would have proposed if it had made MACT floor determinations. The measurement methods are technically limited such that some of the detection limits are above the numerical standards that would have been applicable. There was also an element of cost as many of the sources in this class of units have no means to obtain a representative sample for the measurement methodologies. Concerns about how to characterize the emissions profile from a converted boiler

could be addressed by using a default value equal to three times the detection limit of the reference test method (3xDL) for use in the emissions averaging calculation. This would enable sources to realize the environmental benefits of converting to natural gas (gas 1) without trying to test for pollutants with very low emission rates. However, if an owner/operator determined it to be feasible and desirable, they could alternatively conduct one time emissions testing with the natural gas/other gas 1 fuels to determine actual emission rates and use those if they are above detection levels. Further, as we have stated, such a converted unit would otherwise comply with the requirements for a gas 1 boiler or process heater.

Response: The EPA acknowledges this comment and thanks the commenter for their suggestion on how to address the emission profile from a converted coal-fired boiler.

Commenter Name: Steve Gossett

Commenter Affiliation: Eastman Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3669-A2

Comment Excerpt Number: 42

Comment: EPA's decision to propose work practice standards for gas 1 units is based on its determination that the application of measurement technology to this particular class of sources is not practicable due to technological and economic limitations (see section 112(h)(2)(B) of the Act). This decision was driven, in part, by the extremely low numerical emission limits that EPA would have proposed if it had made MACT floor determinations. The measurement methods are technically limited such that some of the detection limits are above the numerical standards that would have been applicable. There was also an element of cost as many of the sources in this class of units have no means to obtain a representative sample for the measurement methodologies. Concerns about how to characterize the emissions profile from a converted boiler could be addressed by using a default value equal to three times the detection limit of the reference test method (3xDL) for use in the emissions averaging calculation. This would enable sources to realize the environmental benefits of converting to natural gas (gas 1) without trying to test for pollutants with very low emission rates. However, if an owner/operator determined it to be feasible and desirable, they could alternatively conduct one time emissions testing with the natural gas/other gas 1 fuels to determine actual emission rates and use those if they are above detection levels. Further, as we have stated, such a converted unit would otherwise comply with the requirements for a gas 1 boiler or process heater.

As both the case law and prior EPA precedent demonstrate, EPA has all the latitude it needs under the Clean Air Act to allow emissions averaging across all units at a given facility that are subject to Subpart DDDDD, so long as they have an applicable numeric emission limit. Our suggested revisions would establish the numeric emission limit for an existing solid or liquid fired unit converted to gas1 based on the emission limit applicable to the unit prior to conversion.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 57.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 58

Comment: As both the case law and prior EPA precedent demonstrate, EPA has all the latitude it needs under the Clean Air Act to allow emissions averaging across all units at a given facility that are subject to Subpart DDDDD, so long as they have an applicable numeric emission limit. Our suggested revisions would establish the numeric emission limit for an existing solid or liquid fired unit converted to gas 1 based on the emission limit applicable to the unit prior to conversion. In reality, choosing to convert a solid- or liquid-fired unit to fire natural gas/gas 1 fuels is one among many control technologies that a source could evaluate as it seeks to find the most cost-effective approach to comply with the rule. Some member companies have already invested a considerable amount of resources into studying exactly that question: What is the most cost-effective compliance strategy? One member company performed in-depth engineering evaluations of a wide variety of technologies to identify the most rational approach for the simultaneous control of HAPs, SO₂ (for the NAAQS), NO_x (for ozone season controls), and greenhouse gases from its coal fired units. If that company concluded that co-firing 50% natural gas with 50% coal was the optimal MACT control technology for some of its boilers, EPA would allow that company to average the emissions from those 50/50 units along with the emissions of similar units firing 100% coal. Likewise, if it concluded that co-firing 90% natural gas with 10% coal was the optimal MACT control technology for some of its boilers, EPA would allow it to average the emissions of those 90/10 units with similar units firing 100% coal. It is inconceivable why EPA would not then allow that company to convert a coal unit to fire 100% natural gas and average with similar units firing coal provided that the company demonstrated to its own satisfaction that such co-firing and full conversion approaches are technically feasible and commercially advantaged. Yet EPA's arbitrarily narrow interpretation of emissions averaging stands as the greatest impediment to such a solution.

Converting a solid- or liquid-fired unit to natural gas should be treated by EPA as one among the many control technologies that a source may elect to adopt to comply with the rule. Such a reading would not require that a converted unit be "re-subcategorized"; rather, EPA should only require that the unit use a default three times the detection limit of the applicable reference method (3xDL) for use in emissions averaging calculations to demonstrate its emissions profile (or actual test results if feasible and above detection limits at the owner/operators discretion). This would allow EPA to maintain the integrity of its original Gas 1 subcategory and the legal precedents which resulted in its reasonable conclusion to require work practice standards for units in that subcategory. But it would also allow sources the flexibility to adopt, if the source so chooses, to install a firing system technology to comply with the rule, rather than a back-end equipment technology.

Response: The agency has considered all but disagrees with most of the commenters' assertions and notes that the commenters provide no data to support their assertions regarding the comparative cost-effectiveness of various control technologies. Further, as explained response to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 53, we do not believe emissions averaging between units in different subcategories is appropriate. Finally, the commenter appears to suggest that units converted to natural gas should be subject to the numeric emissions limits for the type of boiler from which the unit was converted (e.g., solid or liquid fuel). However, the commenter does not provide any explanation or analysis as to whether or how such a numeric limit would represent MACT for units converted to natural gas, or even for the commenter's suggested subcategory of units that combust (for example) solid fuel plus units converted from solid fuel to natural gas, as would be required by section 112(d).

Commenter Name: Steve Gossett
Commenter Affiliation: Eastman Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3669-A2
Comment Excerpt Number: 43

Comment: In reality, choosing to convert a solid- or liquid-fired unit to fire natural gas is one among many control technologies that a source like Eastman could evaluate as it seeks to find the most cost-effective approach to comply with the rule. Eastman has invested a considerable amount of resources into studying exactly that question: What is the most cost-effective compliance strategy. Eastman performed in-depth engineering evaluations of a wide variety of technologies to identify the most rational approach for the simultaneous control of HAPs, SO₂ (for the NAAQS), NO_x (for ozone season controls), and greenhouse gases from its coal fired units. If Eastman concluded that co-firing 50% natural gas with 50% coal was the optimal MACT control technology for some of its boilers, EPA would allow Eastman to average the emissions from those 50/50 units along with the emissions of similar units firing 100% coal. Likewise, if Eastman concluded that co-firing 90% natural gas with 10% coal was the optimal MACT control technology for some of its boilers, EPA would allow Eastman to average the emissions of those 90/10 units with similar units firing 100% coal. It is inconceivable why EPA would not then allow Eastman to convert a coal unit to fire 100% natural gas and average with similar units firing coal. Eastman has demonstrated to its own satisfaction that such co-firing and full conversion approaches are technically feasible, yet it is EPA's arbitrarily narrow interpretation of emissions averaging which stands as the greatest impediment to such a solution.

Converting a solid- or liquid-fired unit to natural gas should be treated by EPA as one among the many control technologies that a source may elect to adopt to comply with the rule. Such a reading would not require that a converted unit be "re-subcategorized"; rather, EPA should only require that the unit use a default three times the detection limit of the applicable reference method (3xDL) for use in emissions averaging calculations to demonstrate its emissions profile (or actual test results if feasible and above detection limits at the owner/operators discretion). This would allow EPA to maintain the integrity of its original Gas 1 subcategory and the legal precedents which resulted in its reasonable conclusion to require work practice standards for units in that subcategory. But it would also allow sources the flexibility to adopt, if the source so chooses, to install a firing system technology to comply with the rule, rather than a back-end equipment technology.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 58.

Commenter Name: Steve Gossett
Commenter Affiliation: Eastman Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3669-A2
Comment Excerpt Number: 51

Comment: Attachment 1

Example of How Allowing Coal-to-Gas Conversion to Emissions Average In Boiler MACT Achieves Far Superior Environmental Results

Case A: Base Case:

A facility has two pulverized coal-fired boilers with a design rating of 315 mmBtu/hr and two older stoker boilers with a design rating of 200 mmBtu/hr. All four burn the same bituminous coal supply containing 1.5 percent sulfur and emit 0.6 lb/mmBtu NO_x. The boilers all have ESPs for particulate matter control and have no control device for acid gases or mercury. The table [see table in Attachment 1 of submittal] shows how the emission rates for these boilers compare to the Boiler MACT final rule:

Case B: Control to Boiler MACT Standards:

To comply with the Boiler MACT, the facility would have to (1) replace the ESPs with fabric filters (2) install a dry injection system to reduce HCl emissions by 56 percent with sorbent, and (3) install an activated carbon injection system to reduce mercury emissions by 56 percent. In this scenario, the sorbent injection system, designed to meet the HCl standard, gets marginal SO₂ reductions of 10 percent.

Case C: Coal-to-Gas Conversion on Two Boilers and Use of Emissions Averaging:

The facility is considering converting the two pulverized coal boilers to natural gas by installing natural gas burners and burner control system. No other major changes are required to the boiler itself (boiler, economizer, fans, feed water, etc.). This approach will cost far less than 50 percent of the replacement cost of the boilers, so this will not constitute a new or reconstructed unit. The facility is considering this option to avoid a large capital investment in air pollution controls so that it can make further capital investments in its growth strategy. The facility has access to an existing natural gas pipeline that can supply this demand and the facility may select this alternative even though it expects its annual operating costs to increase.

This option is far superior to Case B because natural gas (1) has essentially no sulfur, mercury, or chlorine contaminants, (2) natural gas boilers emit lower levels of particulate matter, (3) natural gas burners will emit much less NO_x (0.25 lb/mmBtu compared to 0.6 lb/mmBtu), and (4) combustion of natural gas emits much less greenhouse gases than does combustion of coal (see attached chart).

Comparison of Options: Figure 3 [see submittal for Figure 3] shows the potential benefits of allowing converted coal units to be included in emissions averaging.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 58.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 128

Comment: Under the best of circumstances, a major retrofit of a boiler takes years from project start to finish. EPA has estimated that the installation of an activated carbon injection control system on one combustion unit – a comparatively simple installation – takes about 15 months.³⁵ However, EPA expects a range of control devices will be used to meet the standards, including

fabric filters, activated carbon injection, electrostatic precipitators, wet scrubbers, replacement burners, and combustion controls.³⁶ Further, the sheer number of boilers impacted by the rule will make finding – and then scheduling – the design and construction resources almost impossible. EPA estimates that there are approximately 14,111 units located at 1,704 facilities covered by this rule, and more than 2,000 of these units fire fuels other than gas. 76 Fed. Reg. 80622. Given that EPA has set emissions standards that only a small percentage of non-gas fired existing units can currently meet, almost every single existing unit subject to an emission standard will need to be retrofitted. Boiler owners will need to hire consultants to assist them in designing and performing the retrofit. Thus, across the multitude of industries impacted by this rule, boiler owners will be scrambling to find the very few qualified consultants who can perform the retrofits necessary to make boilers compliant with this stringent rule. There are a limited number of consulting companies with the expertise to assist in such retrofits, and they will likely be unable to assist all of the boiler owners in less than three years, especially when the electric utility industry will be competing for the same resources in order to comply with their own MACT standard. There will be a similar scarcity in equipment vendors, construction contractors, construction equipment (e.g., heavy lifting cranes), skilled labor (e.g., boilermakers), and other critical suppliers. Companies may even be unable to secure the basic building materials and control equipment (e.g., baghouses and scrubbers).

[Footnote 35: EPA, Engineering and Economic Factors Affecting the Installation of Control Technologies for Multipollutant Strategies (2002).]

[Footnote 36: EPA, Regulatory Impact Analysis: National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters, 3-1 (April 2010) ("The control analysis considered fabric filters, carbon bed adsorbers, and activated carbon injection to be the primary control devices for mercury control, electrostatic precipitators for units meeting mercury limits but requiring additional control to meet the PM limits, wet scrubbers to meet the HCl limits, tune-ups, replacement burners, and combustion controls for CO and organic HAP control....")]

Response: Three years is the maximum compliance time authorized under the statute. *See* CAA section 112(i)(3)(A). If sources are unable to comply within 3 years, the owner or operator may seek a 1 year extension of the compliance period from its Title V permitting authority if the source needs the additional time to install controls necessary to comply with the final rule. *See* CAA section 112(i)(3)(B).

Commenter Name: Mary Sullivan Douglas

Commenter Affiliation: National Association of Clean Air Agencies (NACAA)

Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1

Comment Excerpt Number: 53

Comment: EPA has solicited comment on an industry proposal to allow units that switch to natural gas as a compliance option to average emissions with similar units that do not switch to natural gas. NACAA does not see how this concept could be authorized under the Act.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3534-A1, excerpt 53.

14C. Compliance Dates

Commenter Name: Michael Draper

Commenter Affiliation: United Brotherhood of Carpenters and Joiners of America

Document Control Number: EPA-HQ-OAR-2002-0058-3818-A2

Comment Excerpt Number: 1

Comment: I urge you to provide a one year categorical extension of the compliance deadline for Boiler MACT regulations to exceed the existing three year deadline. As you know, Boiler MACT regulations are extremely complex and will touch the lives and livelihoods of thousands of individuals working across our nation's manufacturing industry.

Due to the complicated nature and widespread impact of these rules, many facilities will be forced to implement costly and speedy changes to comply. Specifically, existing Boiler MACT regulations will create enormous demand for both the necessary pollution control equipment and the skilled labor workforce to install such equipment. Not only are these updates costly, but the workforce of skilled laborers to meet this demand is incredibly limited.

Furthermore, in the face of such urgency to comply with Boiler MACT regulations, all affected facilities will be vying for the same resources at the same time. During this timeframe, access to both resources and labor will be limited and strained.

As you can certainly understand, these shortages will result in skyrocketing prices, which will be passed on to customers on the back end by American utilities. We, unfortunately, cannot even pass them along - but facilities within the forest products industry will be forced to absorb them. In addition, this scarcity of resources will lead many to look outside of the United States, creating jobs abroad that could be given to hardworking Americans.

As you can see, this type of shortage would lead to many unnecessary complications. Such a race for compliance would certainly lead to scarcity of resources, loss of American jobs, and an undeniable gridlock in permit offices as an insurmountable number of permits clog up the pipeline.

Response: Section 112(i)(3) provides that EPA must establish a compliance date for existing sources that provides for compliance with emissions standards as expeditiously as practicable, but no later than three years after the effective date of the emissions standard. This provision does not provide EPA authority to categorically extend the compliance date due to factors such as the potential implementation of other MACT standards. Moreover, EPA believes that sources can comply with the numeric emissions limits within three years. Therefore, for the reasons explained in the preamble, EPA is establishing a compliance date for existing sources subject to numeric limits that is three years from the date of publication of today's final action. The EPA disagrees with the commenters that the 3-year compliance deadline is too short considering the number of sources that will be competing for the resources and materials from engineering consultants, permitting authorities, equipment vendors, construction contractors, financial institutions, and other critical suppliers. Section 112(i)(3)(B) allows EPA and state permitting authorities, on a case-by-case basis to grant an extension permitting an existing source up to one additional year to comply with standards if such additional period is necessary for the installation

of controls. This provision should assist those sources for which the 3-year deadline will not provide adequate time to to comply with the requirements of the standard.

The CAA allows CAA Title V permitting authorities the discretion to grant extensions to the compliance time of up to one year if needed for installation of controls. If an existing source is unable, despite best efforts, to comply within 3 years, a permitting authority has the discretion to grant such a source up to a 1-year extension, on a case-by-case basis, if such additional time is necessary for the installation of controls. Permitting authorities should be familiar with the operation of the 1-year extension provision because EPA has established regulations to implement the provision and the provision applies to all NESHAP. *See* 40 CFR 63.6(i)(4)(A). We believe that the permitting authorities have the discretion to use this extension authority to address a range of situations in which installation schedules may take more than 3 years. The EPA believes that building replacement power constitutes the “installation of controls” at a facility to meet the regulatory requirements.

Commenter Name: Lee Zeugin and Lauren Freeman
Commenter Affiliation: Utility Air Regulatory Group (UARG)
Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1
Comment Excerpt Number: 14

Comment: Units needing to install new control equipment to meet the requirements of the revised rule will be hard pressed to meet the MACT limits within the three years specified in the Act. Their task is only complicated by the fact that the recently promulgated EGU MACT rule will put competing demands on control equipment suppliers and installation contractors.

Response: Regarding the commenter's concerns on a reasonable implementation schedule, see the response to comment EPA-HQ-OAR-2002-0058-3818-A2, excerpt 1.

Commenter Name: Paul Noe
Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.
Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1
Comment Excerpt Number: 19

Comment: It will be extraordinarily difficult – if not impossible – for all of the entities with existing boilers to make the changes necessary to comply with this rule in three years. Put simply, the normally Herculean task of performing a boiler retrofit in three years will be made impossible by factors such as the enormous competition for critical resources and the likely gridlock in many state permitting processes that the broad application of this rule and other new rules for utility boilers will create. Many boiler owners will be simply unable to secure equipment and assistance and/or to obtain the state/local permits needed to retrofit their units within three years.

For many reasons, an extended compliance deadline is critical for the regulated community to comply with the uniquely complex and costly Boiler MACT rules, including:

- enormous demands for equipment and skilled labor converging simultaneously from multiple rules requiring billions in investment that will likely force outsourcing equipment fabrication overseas;
- continuing confusion about whether sources are boilers or incinerators and what standards apply when some determinations will depend on responses to the non-hazardous secondary materials (NHSM) petition process;
- within Boiler MACT, uncertainty of which specific subcategory will apply to a combustion unit given definition changes and related uncertainty of the final limits for the subcategory that ultimately is applicable;
- the need for a carefully calibrated control strategy to address multiple regulations and avoid conflicts between control options;
- the need for major capital planning at a time of uniquely challenging economic conditions;
- engineering and permitting logjams due to overwhelmed state staffs;
- complex installation and testing processes to ensure compliance;
- the breadth of sources covered by the Boiler MACT rules; and
- competitive pressures on U.S. manufacturers and the fragile state of our economy.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3818-A2, excerpt 1.

Commenter Name: Dirk J. Krouskop

Commenter Affiliation: MeadWestvaco Corporation (MWV)

Document Control Number: EPA-HQ-OAR-2002-0058-3493-A1

Comment Excerpt Number: 7

Comment: For many reasons, an extended compliance deadline is critical for the regulated community to comply with the uniquely complex and costly Boiler MACT rules, including:

- enormous demands for equipment and skilled labor converging simultaneously from multiple rules requiring billions in investment that will likely force outsourcing equipment fabrication overseas;
- continuing confusion about whether sources are boilers or incinerators and what standards apply when some determinations will depend on responses to the NHSM petition process;
- the need for a carefully calibrated control strategy to address multiple regulations and avoid conflicts between control options;
- the need for major capital planning at a uniquely challenging time;
- engineering and permitting logjams due to overwhelmed state staffs;
- complex installation and testing processes to ensure compliance;
- the breadth of sources covered by the Boiler MACT rules; and
- competitive pressures on U.S. manufacturers.

EPA has extended the compliance timeline in previous MACTs, it would seem appropriate to do so for this standard as it is unique in its impact to virtually all manufacturing.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3818-A2, excerpt 1.

Commenter Name: David A. Buff, Golder Associates Inc.

Commenter Affiliation: Florida Sugar Industry (FSI)

Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1

Comment Excerpt Number: 55

Comment: For many reasons, an extended compliance deadline is critical for the regulated community to comply with the uniquely complex and costly Boiler MACT, including:

- Enormous demands for equipment and skilled labor converging simultaneously from multiple rules requiring billions in investment that will likely force outsourcing equipment fabrication overseas;
- Continuing confusion about whether sources are boilers or incinerators, and what standards apply, when some of these determinations will depend on EPA's responses to petitions for "non-waste" determinations;
- The need for a carefully designed control strategy to address multiple regulations and avoid conflicts between control options;
- The need for major capital planning under uniquely challenging economic circumstances;
- Engineering and permitting logjams due to overwhelmed state staffs;
- Complex installation and testing processes to ensure compliance;
- The breadth of sources covered by the Boiler MACT rules; and
- Competitive pressures on U.S. companies and the fragile state of the national economy.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3818-A2, excerpt 1.

Commenter Name: Stephen E. Woock

Commenter Affiliation: Weyerhaeuser Company

Document Control Number: EPA-HQ-OAR-2002-0058-3523-A1

Comment Excerpt Number: 10

Comment: We agree with EPA that the compliance deadline should be reset to at least three years after promulgation of the rule finalizing the re-proposals. We also believe EPA should adopt longer compliance deadlines because of the technical achievability issues and the economic concerns that will impact our ability to meet the typical 3 year compliance deadline for MACT rules. We refer EPA to the AF&PA et al. comments that address the statutory and legal bases for extending the deadline.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3818-A2, excerpt 1.

Commenter Name: Stephen E. Woock
Commenter Affiliation: Weyerhaeuser Company
Document Control Number: EPA-HQ-OAR-2002-0058-3523-A1
Comment Excerpt Number: 11

Comment: We request EPA consider longer timelines in light of the economic conditions impacting wood products facilities since the onset of the recession and associated "housing bust" has severely undermined markets for wood products. In particular, we are most concerned with affordability of investments in one of the most prevalent biomass boiler types –stokers burning "wet" biomass– at lumber and other forest products mills, especially for controls that would be necessary to meet the particulate matter (PM) limits. While we question generally whether boiler design is consistently a rational basis for differentiating among subcategories for PM3, EPA's new proposal to establish subcategories for PM among boiler types burning solid fuels would exacerbate the economic concerns by making the "wet" biomass stoker limit more stringent than the solid fuel limit in the March 2011 final rule and by creating uneven winners and losers. This could be offset to some degree by providing longer time for evaluating and installing controls as the nascent economic recovery builds, which would enhance the likelihood of affording investments in this struggling sector. Otherwise many of these facilities will be at risk of closing since sustainable business practices cannot support investment where no return can be generally anticipated.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3818-A2, excerpt 1.

Commenter Name: Douglas A. McWilliams
Commenter Affiliation: American Municipal Power
Document Control Number: EPA-HQ-OAR-2002-0058-3685-A2
Comment Excerpt Number: 10

Comment: Approximately 1600 boilers will be required to reduce emissions to comply with the expected final Boiler MACT rule. EPA estimates that investments in control equipment will cost more than \$5 billion. As noted in the comments submitted by Paul Noe of the American Forest and Paper Association, submitted on behalf of a group of industry representatives (hereinafter "AF&PA Industry Comments") these costs are significantly underestimated and are more likely to exceed \$14 billion. In a challenging economy, justifying and acquiring the necessary capital for these improvements will require lengthy negotiations with banks and other financial institutions. Facilities requiring control upgrades will be required to devote significant resources to capital planning purposes. This burden is particularly acute for municipal utilities that do not have personnel dedicated exclusively to environmental compliance planning. Municipally-owned utilities must work through their local council or other political organization to initiate capital planning, solicit and approve bids, finalize compliance plans and allocate necessary funding, which adds significant time to an already complicated compliance planning process. For the City of Orrville, the entire process from initial planning to installation of control equipment is expected to take 4.5 years, assuming no significant adverse public reaction or delays.¹⁷

[[Footnote 17: *See Declaration of Harm, Boiler MACT Major Source Administrative Stay* (Apr. 22, 20 11) (included as Attachment A). [See submittal for Attachment A.]]

Response: See the response to comment EPA-HQ-OAR-2002-0058-3818-A2, excerpt 1.

Commenter Name: Douglas A. McWilliams

Commenter Affiliation: American Municipal Power

Document Control Number: EPA-HQ-OAR-2002-0058-3685-A2

Comment Excerpt Number: 11

Comment: The 1600 sources expected to require new control equipment or retrofits will also place an enormous demand on state permitting and regulatory authorities, engineering design firms, stack testing companies, and fabricators. Sources subject Boiler MACT will not only be competing with each other for access to qualified engineers and equipment they will also be competing with sources subject to the updated NO_x and SO₂ NAAQS, the Cross-State Air Pollution Rule, the Utility MACT, and various Risk and Technology Review sector rules. Given these realities, it is appropriate for EPA to establish the latest compliance date allowed by law.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3818-A2, excerpt 1.

Commenter Name: Richard D. Garber

Commenter Affiliation: Boise Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3686-A2

Comment Excerpt Number: 10

Comment: EPA should provide sources with an alternative to the three-year compliance timeline.

Given the vast number of affected industries, public institutions, utilities and emission units that will be required to engineer, purchase and install new control equipment and implement other process modifications (more than 1600 major source boilers), a 3-year compliance timeline, in many cases, is impracticable.

As stated previously, Boiler MACT, CISWI, and NHSM rules are complex requirements demanding a thorough review of final regulations before a compliance implementation plan can be prepared for a given facility. A critical path timeline is provided below based on information Boise engineers have obtained in conversations and proposals from boiler manufacturers, equipment suppliers, and vendors.

(Conceptual Compliance Timeline)

- Begin 36-month compliance timeline with final promulgation of Boiler MACT, CISWI, and NHSM final rule language
- Months 0-3 -final rule evaluation, fuel testing for determination of fuel or waste under final NHSM rule, identify gaps between existing control equipment and final regulatory requirements
- Months 3-6 - begin design engineering, complete air emissions review and begin preparation of Title V air permit modification applications, and initiate request for vendor guarantees

- Months 6-9 -obtain vendor design guarantees, complete regulatory analyses, emissions modeling, state and federal air regulatory applicability review, control technology review; address regulatory permitting issues and submit Title V air permit application to state and federal permit authorities
- Months 6-24 (12-18 month average) it may be necessary in some cases to obtain a PSD permit due to increases in NOx emissions or other pollutants caused by fuel switches and the inverse relationship between CO and NOx pollutants. PSD permits are complex and the following steps are routinely necessary to obtain a final permit from state and/or federal air permit authorities, including: application review, "completeness" determination, BACT/LAER and regulatory review, modeling review, Title V permit, preparation, negotiation and modification, 30-day public notice, 45-day EPA review, response to comments, and permit issuance.
- Months 12-18- once air permit modification has received preliminary agency review and completeness determination, expected at approximately month 12, company may initiate (inherent risk of stranded funds) final detailed design engineering with suppliers and engineering design firms, expected to take 6 months
- Months 18-30 - once the Title V air permit modification (if necessary) is placed on public notice, company may initiate placement of order, expected at approximately month 18, company may be willing to take risk and place equipment orders (significant risk of stranded funds). Pressure parts, boiler generator tubes, and large fabricated equipment such as electrostatic precipitators and boiler grates have a lead time of 9-12 months from placement of orders (Jansen, B&W), assuming fabrication shop availability.
- Month 24 - receipt of final Title V air permit modification. Beginning of actual construction cannot commence until final signed permit is obtained.
- Months 24-30 - on site construction (preparatory) work begins to include: receipt of ordered equipment, site preparation and foundation work, scheduling of manpower and detailed construction engineering plans to coincide with a major mill outage. Outage must occur prior to compliance deadline and must coincide with available customer, vendor and manpower availability. Furthermore, seasonal cold temperatures preclude shutdowns during certain time periods at many locations in the midwest and northeast locations.
- Months 30-36- receipt of all equipment on site, mill outage scheduled, project construction completed prior to 36 month compliance deadline.
- Additional time needs -for new equipment demonstration and completion of preliminary emissions engineering tests an additional 60-90 days is needed after the final construction, startup, and compliance testing prior to the 36-month compliance deadline.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3818-A2, excerpt 1.

Commenter Name: Dakota Gasification Company Great Plains Synfuels Plant

Commenter Affiliation: David W. Peightal

Document Control Number: EPA-HQ-OAR-2002-0058-3424

Comment Excerpt Number: 9

Comment: In the event of promulgation of any new MACT or other competing EPA standards being promulgated, DGC would prefer more time than the proposed three years in order to safely and adequately assess and address all impacts of the rule or other competing EPA rules, such as the new Ambient Air Quality Standards. This assessment would subsequently involve consideration of the availability of resources (internal and external), engineering involvement, technology options, and new equipment installation. EPA should consider the number of sources affected by this rule and the availability of advanced technological equipment that would be required by those affected sources. In addition, some sources would need adequate time to plan, design, engineer, purchase equipment and materials and then to construct and install equipment. Skilled manpower may be impacted in areas that are in short supply and could be affected by seasonal issues in extreme cold climates which potentially increase contractor and operational personnel safety risk, not to mention additional environmental risk to expedite the changes.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3818-A2, excerpt 1.

Commenter Name: Traylor Champion

Commenter Affiliation: Georgia-Pacific LLC (GP)

Document Control Number: EPA-HQ-OAR-2002-0058-3465-A1

Comment Excerpt Number: 13

Comment: GP supports EPA's proposal to reset the compliance clock for the Boiler MACT rule.

Our company has been actively engineering options to comply with the anticipated standards but final designs and compliance options cannot be selected until a final standard has been established. With hundreds of millions of dollars expected to be necessary to comply with this rule, expenditures of this magnitude cannot possibly be committed until final standards are promulgated. As noted below, complying with the promulgated standards will be difficult, if not impossible to achieve within the normal three-year compliance period.

GP has 84 solid fuel and oil-fired boilers subject to Boiler MACT and it is anticipated that all but 2 of these boilers will require the addition of one or more add-on devices or modifications/upgrades to combustion systems to meet the proposed limits. The normal duration of GP major capital projects from initial concept to completion is three-years, consisting of one-year for technology review and vendor/equipment selection, one-year for engineering and equipment manufacturing, and one-year for construction, startup, commissioning and compliance testing. There are a number of factors that will make it very difficult to get all 82 units in compliance within the proposed three-year time frame.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3818-A2, excerpt 1.

Commenter Name: Traylor Champion

Commenter Affiliation: Georgia-Pacific LLC (GP)

Document Control Number: EPA-HQ-OAR-2002-0058-3465-A1

Comment Excerpt Number: 14

Comment: Internal – The GP corporate engineering group is currently staffed to manage 2-3 major boiler projects at a time. Even if external engineering resources are hired to augment internal resources, we would still need GP engineering/project management to manage and supervise the external resources. Mill staffs at a large pulp and paper mill can typically manage 1-2 ongoing boiler projects at a time, but some of the mills will have as many as 5 boilers that will be impacted by Boiler MACT. Attempting to manage 82 projects concurrently will be difficult or impossible and in addition will increase the cost of compliance due to errors and inefficiency.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3818-A2, excerpt 1.

Commenter Name: Traylor Champion

Commenter Affiliation: Georgia-Pacific LLC (GP)

Document Control Number: EPA-HQ-OAR-2002-0058-3465-A1

Comment Excerpt Number: 15

Comment: External – There are limited engineering, manufacturing and construction resources to design, manufacture and install the required control equipment. All of industry will be placing demands on these resources at the same time. This situation is worse than it normally would be due to the fact that the economy is coming out of a major recession and many of these companies have significantly reduced their workforce.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3818-A2, excerpt 1.

Commenter Name: Traylor Champion

Commenter Affiliation: Georgia-Pacific LLC (GP)

Document Control Number: EPA-HQ-OAR-2002-0058-3465-A1

Comment Excerpt Number: 16

Comment: Utility MACT – The utility version of Boiler MACT is going into effect at essentially the same time as Boiler MACT. Since utilities and industry share the same engineering, manufacturing and construction resource base, we will be competing with the utilities for these resources. The inherent larger size of utility projects will make it difficult for industrial companies to compete.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3818-A2, excerpt 1.

Commenter Name: Traylor Champion

Commenter Affiliation: Georgia-Pacific LLC (GP)

Document Control Number: EPA-HQ-OAR-2002-0058-3465-A1

Comment Excerpt Number: 17

Comment: Outage scheduling – Large pulp and paper mills with multiple boilers typically stagger boiler outages throughout the year due to resource constraints and to minimize the impact on production. In facilities with multiple boilers requiring addition of control devices, it will be necessary to complete some of the installations as much as 12-15 months prior to the compliance

deadline which will significantly compress the normal schedule duration and place additional stress on limited resources.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3818-A2, excerpt 1.

Commenter Name: Dirk J. Krouskop

Commenter Affiliation: MeadWestvaco Corporation (MWV)

Document Control Number: EPA-HQ-OAR-2002-0058-3493-A1

Comment Excerpt Number: 5

Comment: MWV believes that the three year compliance timeline outlined by EPA is insufficient to ensure that adequate well conceived control systems will be employed. EPA proposes to reset the compliance deadline for existing affected sources to three years after the date of publication of the Final Reconsideration Rule in the Federal Register. MWV supports this proposal but doesn't believe it goes far enough. It would be inappropriate for EPA to expect sources to comply with this set of rules within 3 years of the original date of March, 20 11 after more than one year of reconsideration. MWV believes that it will be extremely difficult to install the necessary equipment across our fleet of boilers within the three year timeline. MWV has been developing compliance strategies for each of its impacted boilers over the past three years and as the requirements continue to change major and minor adjustments to the strategy continue to be made. To properly engineer, permit, procure, install and learn to operate the equipment within three years may be achievable for one unit, but it is not reasonable to expect the same for multiple units across multiple facilities.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3818-A2, excerpt 1.

Commenter Name: Dirk J. Krouskop

Commenter Affiliation: MeadWestvaco Corporation (MWV)

Document Control Number: EPA-HQ-OAR-2002-0058-3493-A1

Comment Excerpt Number: 6

Comment: MWV is concerned that the overlap of requirements from these rules with existing provisions that existing units face and are expected to encounter in future regulatory actions will result in an unworkable set of requirements. EPA has the freedom in its regulatory approach to consider only the impact of this set of rules (includes the major and area source rule, non-hazardous secondary materials rule and solid waste incinerator rule). MWV does not have that luxury. MWV must consider the impact of this set of rules, existing requirements and control technologies, as well as impacts on water and waste regulations. MWV must also factor in future requirements that could potentially apply such as more stringent ambient air quality standards or transport rules. These impacts are real considerations for MWV and require broader strategic decisions than merely compliance with this rule. For this reason alone, EPA should allow for additional time to comply than the three years that have been proposed.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3818-A2, excerpt 1.

Commenter Name: Timothy Serie
Commenter Affiliation: American Coatings Association (ACA)
Document Control Number: EPA-HQ-OAR-2002-0058-3502-A1
Comment Excerpt Number: 14

Comment: ACA generally supports the following proposed changes in the Boiler MACT rule:

Extending the compliance date for existing sources to three years after the date of publication of the final reconsideration of the rule; although ACA urges EPA to be flexible and allow affected sources more than three years to comply with the rules, if needed

Response: See the response to comment EPA-HQ-OAR-2002-0058-3818-A2, excerpt 1.

Commenter Name: Lorraine Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1
Comment Excerpt Number: 129

Comment: In order to retrofit a boiler, the owner will need to line up the capital necessary to pay for the retrofit. In these difficult economic times, just securing the necessary capital may take months, if not years, assuming the capital can be obtained from lending sources. In addition, the owner will need to go through the relevant permitting process(es), which will similarly take months, if not years. Finally, once the finances are secure and the permitting is complete, the owner will actually need to perform the retrofit. The design, procurement, installation, and shakedown of a retrofit project (e.g., installing a scrubber on a large boiler) can easily take more than three years. An example of a rulemaking that involved control retrofits over an extended compliance period is the implementation of the 1-hour ozone SIP requirements in Houston, Galveston, and Brazoria Counties in Texas. Due to the magnitude of the NO_x emissions reductions required and the number of sources affected, emission reduction projects were implemented over a 6-year timeframe (2001-2007), with a total capital investment of over \$3 billion. As the Boiler MACT will involve more significant emission controls retrofits, it is appropriate to allocate a longer compliance timeframe.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3818-A2, excerpt 1.

Commenter Name: Lorraine Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1
Comment Excerpt Number: 130

Comment: In addition, the timing of the retrofit work needs to be carefully planned, particularly for boilers that provide the primary and/or base load energy supply for their facilities. A facility owner will only shut down a boiler when everything is properly staged to ensure minimal disruption of the facility's operation. In addition to ensuring that the design work is completed and the control equipment and other supplies are on-site and ready for installation, the facility owner needs to make sure that the full suite of consultants and laborers are available for the

installation. Based on a discussions with a number of potentially affected companies, the turnaround or shutdown cycles for boilers and process heaters at many of the facilities can vary from 1 to 5 years, making this type of precise staging exceedingly difficult to do in a three year period without substantial business interruption.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3818-A2, excerpt 1.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 131

Comment: Finally, in many instances, the installation of pollution control equipment and associated charges to boiler must be permitted under state air pollution statutes and/or construction codes (building permits, etc.). The proposed rule will result in an increase in the number of permit applications, potentially swamping the state and local agencies. Even in those areas where the rule may not result in significant increases in permitting work, the normal delays associated with permitting may make meeting the three year compliance deadline impossible.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3818-A2, excerpt 1.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 132

Comment: In its lengthy discussion in the preamble to this Reconsideration Proposal, EPA has accurately highlighted most of the reasons why the compliance date needs to be revised in the final reconsidered rule. *Id.* ACC strongly supports the Agency providing the maximum compliance time frame allowed by the CAA for sources to come into compliance with a complex, costly and widely applicable rule.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3818-A2, excerpt 1.

Commenter Name: Alicia Meads

Commenter Affiliation: National Association of Manufacturers (NAM)

Document Control Number: EPA-HQ-OAR-2002-0058-3515-A1

Comment Excerpt Number: 1

Comment: Impractically truncate capital planning time. These proposed rules do not provide enough time for capital planning and compliance, given the complexity of the rules and competition for a limited pool of qualified domestic vendors and installers for emission controls and boilers. Additional time is needed to allow businesses to synch up compliance with these rules with compliance on upcoming National Ambient Air Quality Standard rules.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3818-A2, excerpt 1.

Commenter Name: Alicia Meads

Commenter Affiliation: National Association of Manufacturers (NAM)

Document Control Number: EPA-HQ-OAR-2002-0058-3515-A1

Comment Excerpt Number: 11

Comment: The EPA proposes to set the compliance deadline for existing affected sources at three years after the date of publication of the Final Rule in the Federal Register. 76 Fed. Reg. At 80,605. It will be extraordinarily difficult – if not impossible – for all of the entities with existing boilers to make the changes necessary to comply with this rule in the three year timeframe that the EPA proposes. Put simply, the task of performing a boiler retrofit in three years will be made nearly impossible by the competition for critical resources and the likely gridlock in many state permitting processes that the broad application of this rule will create. Many boiler owners will be simply unable to secure equipment and assistance and/or to obtain the state/local permits needed to retrofit their units within three years.

Even under the best of circumstances, a major retrofit of a boiler takes years from project start to finish. The EPA has estimated that the installation of an activated carbon injection control system on one combustion unit – a comparatively simple installation – takes about 15 months.³ However, the EPA expects a range of control devices will be used to meet the standards, including fabric filters, carbon bed adsorbers, activated carbon injection, electrostatic precipitators, wet scrubbers, replacement burners, and combustion controls.⁴

Further, the sheer number of boilers impacted by the rule will make finding – and then scheduling – the design and construction resources almost impossible. The EPA estimates that approximately 5,500 boilers would need to meet emission limits under the rules.⁵ Many, if not all, of these boilers would need to be retrofitted. Boiler owners will need to hire engineers to assist them in designing and performing the retrofit. Thus, across the various industry sectors impacted by this rule, boiler owners will be competing for qualified engineers to design, permit and perform the retrofits necessary to make boilers compliant with this stringent rule. There will be a similar scarcity in equipment vendors, construction contractors, construction equipment (e.g, heavy lifting cranes), skilled labor (e.g., boilermakers), and other critical suppliers. Companies may even be unable to secure the basic building materials and control equipment(e.g., baghouses and scrubbers).

In order to retrofit a boiler, the owner will need to line up the capital necessary to pay for the retrofit. In these difficult economic times, just securing the necessary capital may take significant time. In addition, the owner will need to go through the relevant permitting process(es), which will take a number of months. Finally, once the finances are secure and the permitting is complete, the owner will actually need to perform the retrofit. The design, procurement, installation, and shakedown of a retrofit project (e.g., installing a scrubber on a large boiler) can easily take multiple years.

[Footnote 3: EPA, *Engineering and Economic Factors Affecting the Installation of Control Technologies for Multipollutant Strategies* (2002).]

[Footnote 4: EPA, *Regulatory Impact Analysis: National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters*, 3-1 (April

2010) ("The control analysis considered fabric filters, carbon bed adsorbers, and activated carbon injection to be the primary control devices for mercury control, electrostatic precipitators for units meeting mercury limits but requiring additional control to meet the PM limits, wet scrubbers to meet the HCl limits, tune-ups, replacement burners, and combustion controls for CO and organic HAP control, and carbon injection for dioxin/furan control.")]

[Footnote 5: <http://www.epa.gov/airquality/combustion/docs/20111202presentation.pdf>.]

Response: See the response to comment EPA-HQ-OAR-2002-0058-3818-A2, excerpt 1.

Commenter Name: Alicia Meads

Commenter Affiliation: National Association of Manufacturers (NAM)

Document Control Number: EPA-HQ-OAR-2002-0058-3515-A1

Comment Excerpt Number: 12

Comment: The timing of the retrofit work needs to be carefully planned, particularly for boilers that provide the primary and/or base load energy supply for their facilities. A facility owner will only shut down a boiler when everything is properly staged to ensure minimal disruption of the facility's operation. Based on a discussions with a number of potentially affected companies, the turnaround or shutdown cycles for boilers at many of the facilities is so long as to make this type of precise staging exceedingly difficult to do in a three year period without substantial business interruption.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3818-A2, excerpt 1.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 23

Comment: Since the boiler rules establish limits on multiple pollutants, multiple controls will be required, and trade-offs posed by the various controls must be considered. For example, presence of SO₃ can have a significant negative impact on the Hg removal that is achieved by activated carbon injection, and use of catalysts for NO_x and CO control can oxidize SO₂ in flue gas to SO₃. However, presence of SO₃ in flue gas tends to improve PM collection efficiency of ESPs by lowering ash resistivity. Fuels with higher sulfur or chloride contents will combine with available mercury to form particulates that are more easily captured in particulate control devices, while boilers burning fuels with low sulfur and chloride contents will emit any mercury present in the fuel in its elemental form, which is harder to capture. Injection of sorbent to control HAPs prior to a PM control device may increase PM emissions over baseline. Weighing these many considerations will increase the time required to formulate and evaluate control strategy, and a strategy cannot be finalized prior to the promulgation of the rules. The standard three year compliance timeframe does not recognize or address these pollutant interactions and control implications and their impact on compliance approaches or required compliance timing.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3818-A2, excerpt 1.

Commenter Name: Steve Gossett
Commenter Affiliation: Eastman Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3669-A2
Comment Excerpt Number: 34

Comment: Comment Summary: We fully support EPA's proposal to re-set the three-year compliance period and urge EPA to seek methods similar to Utility MACT to grant extensions beyond the additional year provided under the Clean Air Act.

Discussion: Eastman supports EPA's intent to "reset" the three year compliance period and to exercise its enforcement discretion with regards to the administrative requirements that followed from the court's vactur of EPA's administrative stay of the final rule (Jackson, L. Letter to Senator Ron Wyden. 18 January 2012). Eastman is uniquely impacted by this rule by virtue of having ten coal-fired units at the company's Tennessee Operations (TNO) potentially subject to the rule. Eastman recognized that complying with the MACT rule in three or four years, and simultaneously with the other rulemakings underway on overlapping timeframes (e.g. SO2 NAAQS, Regional Haze SIP, and CISWI), etc.), would be extremely challenging and could potentially expose the company to significant business risk if no actions were taken until the rule was finalized. Eastman therefore proactively committed a significant amount of time and resources into planning a coordinated response to this rule before the rule was finalized based on our best guess as to the rule's final outcome. This effort to "hit the ground running", which included technical analysis and optimization of pollution control technologies as well as development of detailed project and life cycle cost estimates and construction schedules, was essential to understanding the overall business risk to the company. One of the key learnings that resulted from these investigations was the duration of the overall project at a site of exceptional complexity such as TNO. Given reasonable assumptions about the duration of detailed engineering, equipment lead times, pre-outage fabrication and site preparation, and unit shutdowns for pollution control tie-ins and commissioning, Eastman concluded that it would take between 39 and 42 months from the rule's finalization to get the first unit converted & in full compliance with the new rule. Given that Eastman has ten units potentially subject to the rule, each of which will require nominally four to six weeks of conversion and commissioning; and given that TNO is complex integrated site that requires nominally fourteen steam generating boilers in service to remain operational; and given that the statute allows 36 to 48 months to be in compliance; it is self-evident that Eastman cannot convert all its potentially subject units without dramatically increasing its business risk.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3818-A2, excerpt 1.

Commenter Name: Steve Gossett
Commenter Affiliation: Eastman Chemical Company
Document Control Number: EPA-HQ-OAR-2002-0058-3669-A2
Comment Excerpt Number: 35

Comment: Eastman recognizes that EPA lacks the authority to grant additional time because the statue establishes the compliance period to be three years from the final rule's publication in the federal register, with a provision for a fourth year. However, Eastman noted with great

interest that EPA has chosen to exercise its enforcement discretion subsequent to the court's vacatur of the EPA's administrative stay of this rule, as well as the ongoing debate around the Utility MACT Rule (MATS) and the President's authority under Section 112 to exempt stationary sources from compliance for two years where the President determines that "the technology to implement such standard is not available". Having already demonstrated its commitment to responsible environmental stewardship by investing many millions of dollars in engineering before the rule has even been finalized, EPA should recognize that Eastman is attempting to position itself to comply with all possible haste. Eastman contends that the air pollution control industry's ability to manufacture the equipment required to comply with this rule for all sources nationwide, and sources ability to deploy the construction labor necessary to install it, is going to be seriously challenged due to the concurrent timing of the Industrial Boiler MACT rule with the Utility MACT rule. When these strains on the supply of engineering, equipment, and construction labor are considered alongside the impending additional demands due to CSAPR, Regional Haze and the NAAQS for SO₂, Eastman is not convinced that the required hardware and labor will be available within the statutory deadline. As one of the nation's largest exporters, competing daily against foreign competitors both at home and abroad, Eastman encourages EPA to exercise as much discretion as it is allowed under the statute to enable sources to balance the goals of environmental stewardship against the considerable business risk incurred by rushing the implementation of this rule.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3818-A2, excerpt 1.

Commenter Name: Traylor Champion

Commenter Affiliation: Georgia-Pacific LLC (GP)

Document Control Number: EPA-HQ-OAR-2002-0058-3465-A1

Comment Excerpt Number: 18

Comment: Control technologies – There are four different pollutants regulated by Boiler MACT – PM, CO, HCl, and Hg. The control of these pollutants can directly impact emissions of other pollutants or impact the performance of existing pollution control devices:

Pollutant interactions – The most notable is the relationship between NO_x and CO. The inverse relationship between NO_x and CO is well established. The generation of both pollutants is a function of combustion conditions in the furnace – excess air, time, temperature and turbulence. CO emissions are minimized by having high excess air and significant time at high temperature and turbulence. These same conditions maximize NO_x emissions. Most industrial boilers control NO_x emissions by controlling combustion conditions in the furnace utilizing a combination of techniques including low excess air, low NO_x burners, staged combustion, and flue gas-recirculation. The requirement to also control CO emissions may require development of a strategy for controlling one of the two by controlling combustion conditions and the other by back-end cleanup. If it turns out that the most cost effective solution is to control CO in the furnace and NO_x by back end clean-up, existing NO_x control systems will have to be replaced with SCR or SNCR which will take additional time to implement.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3818-A2, excerpt 1. Also address pollutant interactions.

Commenter Name: Traylor Champion
Commenter Affiliation: Georgia-Pacific LLC (GP)
Document Control Number: EPA-HQ-OAR-2002-0058-3465-A1
Comment Excerpt Number: 19

Comment: Interaction Between Control Technologies – Control of Hg may require utilization of activated carbon injection (ACI). The additional particulate loading in the gas stream will have to be collected by the PM control device. The net impact on PM emissions won't be known until the ACI system is operational and stack PM emissions are measured. In these situations, the optimal control strategy would be a staged implementation consisting of installation of new control technology to address the Boiler MACT pollutants followed by corrective action to address the impact on other pollutants or pollution control devices. The time constraints make this impractical and compliance costs may increase as a result.

The absorption efficiency of ACI in any given system is unknown. Degree of mixing, duct length (retention time), duct geometry, and amount of ACI introduced all play important roles in capture efficiency. ACI is much more effective on oxidized Hg vs elemental Hg. To reach any given level of Hg reduction, optimizing ACI usage and Hg oxidizers will require some time to get the right combination. Because the amount of ACI needed to accomplish the required HG+ absorption is unknown, it makes the design of the baghouse much more complicated. Simply overdesigning the baghouse and the ACI delivery system would waste precious resources.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3818-A2, excerpt 1.

Commenter Name: Mark Anthony
Commenter Affiliation: Alyeska Pipeline Service Company
Document Control Number: EPA-HQ-OAR-2002-0058-3684-A2
Comment Excerpt Number: 1

Comment: Our organization has been evaluating the timeframe necessary to comply with Boiler MACT, assuming the final rule is similar to the present vacated final rule and this proposed rule. The 3 year time line will be extraordinarily difficult to meet because the modifications required of the boiler facility to provide for controls is very challenging.³ After those changes the addition of emission controls will be equally difficult and time consuming. We are not optimistic we can meet a three year timeframe to perform this project. We are without other options for power for the VMT so any project is particularly challenging because it directly impacts the ability of the facility to perform its primary function of storing oil and loading it onto marine tankers.

[Footnote]

(3) The Valdez boiler facility is located on the side of a mountain with very little room for construction equipment and to make changes to provide the additional area for the emission controls to be added. The boiler facility is a very tightly configured facility that houses the boilers, power generation and vapor handling all within one constricted area. Valdez is a very remote location with limited facilities. Much of the construction must be accomplished during

the "peak" summer months. Acquiring contractors with the necessary skilled workers has historically been a challenge for large projects.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3818-A2, excerpt 1.

Commenter Name: Randall D. Quintrell

Commenter Affiliation: Georgia Paper & Forest Products Association

Document Control Number: EPA-HQ-OAR-2002-0058-3451-A1

Comment Excerpt Number: 7

Comment: The three year compliance window totally ignores the logistical challenges of implementation. This is particularly true when one considers the extremely stringent emission limits being proposed, the uncertainty that a particular technology may even achieve compliance with such limits on a particular unit, and the very large number of boilers that are affected by this rule that will stretch engineering, design and construction resources beyond realistic expectations and escalate costs due to scarcity of such resources within such a tight framework. The compliance deadline should rationally be set at no less than 5 years for all solid fuel boilers and all liquid fuel boilers, and EPA should move forward immediately to secure an extension of the deadline to 5 years for these units.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3818-A2, excerpt 1.

Commenter Name: Traylor Champion

Commenter Affiliation: Georgia-Pacific LLC (GP)

Document Control Number: EPA-HQ-OAR-2002-0058-3465-A1

Comment Excerpt Number: 20

Comment: GP urges EPA to reset the compliance clock with the reconsidered final rule, automatically provide for the one-year extension to the compliance date allowed by the CAA, and consider allowing up to five-years for compliance with the final rule.

As noted in the AF&PA comments, EPA has the option for accomplishing a significantly longer compliance deadline as a Presidential extension under §112(i)(3)(B) of the CAA.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3818-A2, excerpt 1.

Commenter Name: Wayne J. Galler

Commenter Affiliation: Georgia Industry Environmental Coalition

Document Control Number: EPA-HQ-OAR-2002-0058-3479-A1

Comment Excerpt Number: 1

Comment: GIEC strongly supports a longer than three years compliance time as the changes that will have to be made across all industry groups to upgrade boilers to meet the new standards cannot realistically be met in a three-year time frame. This is due to outside limitations on the availability of design engineering, construction and equipment installation contractors to complete the work for as many as 3,000 boilers that will require retrofits or upgrades nationwide.

We believe EPA should consider a five-year compliance schedule as discussed in the comments submitted by AF & PA.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3818-A2, excerpt 1.

Commenter Name: David A. Buff, Golder Associates Inc.

Commenter Affiliation: Florida Sugar Industry (FSI)

Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1

Comment Excerpt Number: 56

Comment: At a minimum, EPA should automatically allow an additional one year to comply, as provided in 40 CFR Part 63, Subpart A. Moreover, EPA should recognize that a one year extension is not sufficient in this case due to the large number of sources that will need to make modifications at their existing facilities. Accordingly, the compliance deadline for the upcoming boiler rules should be extended to five years to ensure affected facilities will be able to achieve the required emissions reductions prior to the compliance dates of the rules.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3818-A2, excerpt 1.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 10

Comment: We strongly support the proposed reset of the three year compliance time, but believe five years is needed for existing sources subject to numerical emission limits to comply with this proposal.

1. EPA is proposing to reset the compliance date for existing sources to 3 years after the date of publication of these amendments in the Federal Register.

We strongly support extending the existing source compliance date, since design, engineering, procurement and installation of controls will take a long time. Furthermore, facilities cannot be sure what will be required for many BPH since changes from this proposal are likely and thus the facilities cannot begin project activities until this proposal is finalized. In addition to the actual time needed to install controls, compliance time also needs to be extended due to the potential triggering of other rules and regulatory requirements, such as the NSPS standards for new steam generating units (boilers) and NSR/PSD or state construction permitting (e.g. due to NO_x increases) which delays construction until a permit is received. Finally, the coincident impact of the electric utility unit NESHAP, the area source and CISWI rules, the NSPS Ja rule, and a variety of other regulations impacting BPH, on the availability of combustion and combustion emission control resources and equipment will certainly extend the time to implement the controls required under this rule. [See submittal for referral to comments previously submitted on 2010 proposal.]

Response: See the response to comment EPA-HQ-OAR-2002-0058-3818-A2, excerpt 1.

Commenter Name: Gretchen Brewer
Commenter Affiliation: PT AirWatchers
Document Control Number: EPA-HQ-OAR-2002-0058-3825-A1
Comment Excerpt Number: 3

Comment: Proposed compliance date: Yes. Given that EPA's imminent rule changes have been well publicized, it is more than reasonable that boiler plans embarked upon after the original date of June 4, 2010 must be considered as new boilers. The technology to comply is well known to the industry and readily available, so they have every reason to go with the better technology.

We have been particularly concerned about this issue given the glut of plans for new boilers, as an example for biomass power generation, in which it is widely discussed by proponents whether they will "be able to beat" the new regulations. The wide publicity and protracted lead time of these regulations is more than sufficient for the owners of these facilities to incorporate the new emissions limits into their plans.

Response: The EPA thanks the commenter for their support. CAA section 112(a)(4) states that a new source is a stationary source if "the construction or reconstruction of which is commenced after the Administrator first proposes regulations under this section establishing an emissions standard applicable to such source." EPA first proposed the Boiler MACT standards under this particular rulemaking record on June 4, 2010, following the DC Circuit's vacatur of the previous major source boilers rule in 2007. While today's action revises certain new source standards, it is a reconsideration action and is premised on the same general rulemaking record. It is thus reasonable to view the date EPA "first proposes" standards for the area source category to be the June 4, 2010 date. Further, the commenter essentially advocates an approach whereby any time the Agency changes a new source standard, in any way, on reconsideration, the new source trigger date would change. Such a result is not consistent with Congress' intent in defining the term "new source" in section 112(a)(4), to be the date the Agency "first proposes" standards.

Commenter Name: Lenny Dupuis
Commenter Affiliation: Dominion Resources Services, Inc.
Document Control Number: EPA-HQ-OAR-2002-0058-3486-A1
Comment Excerpt Number: 10

Comment: We strongly support EPA's proposal to revise the compliance date for existing sources to 3 years after the date of official publication of the final reconsideration rule. This will provide affected units sufficient time to evaluate compliance strategies, develop compliance plans and install necessary controls. We also support the proposed 60 days after the date of official publication of the final reconsideration rule or upon startup, whichever is later, for new sources.

Response: The EPA thanks the commenter for their support.

Commenter Name: Annabeth Reitter
Commenter Affiliation: NewPage Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3662-A2
Comment Excerpt Number: 5

Comment: NewPage Corporation supports resetting the compliance dates.

Response: The EPA thanks the commenter for their support.

Commenter Name: Pamela Lacey
Commenter Affiliation: American Gas Association (AGA)
Document Control Number: EPA-HQ-OAR-2002-0058-3672-A2
Comment Excerpt Number: 5

Comment: We support your proposal to extend the compliance date for existing sources to three years after the date of publication of the final reconsideration rule and to extend the compliance date for new sources until 60 days after publication of the final rule for the reasons stated in the preamble. Id.

Response: The EPA thanks the commenter for their support.

Commenter Name: Heather Parent
Commenter Affiliation: Maine Department of Environmental Protection
Document Control Number: EPA-HQ-OAR-2002-0058-3691-A2
Comment Excerpt Number: 8

Comment: Maine DEP supports the EPA's extension of the deadline for achieving compliance with the rule and for performing initial compliance testing to give affected sources an adequate amount of time to make any necessary changes.

Response: The EPA thanks the commenter for their support.

Commenter Name: Lee Zeugin and Lauren Freeman
Commenter Affiliation: Utility Air Regulatory Group (UARG)
Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1
Comment Excerpt Number: 12

Comment: EPA proposes to revise the compliance date for existing units to three years after the date of publication of the final reconsideration rule and for new units until 60 days after the reconsideration rule is published. UARG agrees with and supports these extensions of the compliance dates for the revised rule.

Response: The EPA thanks the commenter for their support.

Commenter Name: Lee Zeugin and Lauren Freeman
Commenter Affiliation: Utility Air Regulatory Group (UARG)
Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1
Comment Excerpt Number: 15

Comment: EPA should reset the compliance clock and provide existing units three years and new units 60 days to comply with the IB MACT after the final reconsideration rule is published in the Federal Register.

Response: The EPA thanks the commenter for their support.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 123

Comment: EPA proposes to reset the compliance deadline for existing sources to 3 years from the effective date of the final reconsidered boiler major source rule. For new sources, EPA proposes to reset the compliance date to 60 days after promulgation of the final reconsidered rule.

EPA clearly has authority to reconsider and revise standards pursuant to §307 of the Clean Air Act. After such reconsideration and revision to the standards, “there will be circumstances where EPA changes a rule so extensively that the amended rule should be regarded as a new standard.”

Pesticide Active Ingredient (PAI) NESHAP, 67 Fed. Reg. 38200, 38201 (June 3, 2002). Sources need time to come into compliance with such “new standards.” *Id.*

Section 112(i)(3)(a) gives EPA the flexibility to allow existing sources up to 3 years to meet “any emissions standard”. As noted above, EPA used this authority in the revised PAI rule to establish a new compliance deadline for existing sources that was an additional 16 months from the deadline in the original final rule. *Id.* EPA took similar action in establishing a new compliance deadline after reconsideration and promulgation of revised standards in the Miscellaneous Organic Chemicals Manufacturing (MON) NESHAP, 71 Fed. Reg. 10439, 10440 (Mar. 1, 2006).

EPA’s reasoning in extending/resetting the compliance deadline in both the PAI and the MON is equally applicable to this rulemaking. In those NESHAP rules, EPA reasoned that § 112(i)(3) is ambiguous as to whether an initial compliance date applies to a rule that has been substantially revised. EPA asserted, and in the case of the MON ACC concurred in comments, that when provisions of a rule are changed to such a degree that the amended rule triggers a new effective date, this is a new “emission standard” requiring a new compliance deadline. Additionally, § 112(d)(6) requires EPA to review and if necessary revise § 112 standards no less than every 8 years. If the underlying standard is revised, it is axiomatic that a new compliance deadline would have to be established to allow sources to come into compliance with the revised rule.

Response: The EPA thanks the commenter for their support.

Commenter Name: Lee Zeugin and Lauren Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1

Comment Excerpt Number: 13

Comment: Compliance with the final rule has been greatly complicated by two events that occurred following the publication of the rule in the Federal Register: (1) the indefinite stay of the rule that EPA issued on May 18, 2011¹⁰ and (2) the subsequent vacatur of that stay by the U.S. District Court for the District of Columbia.¹¹ EPA's stay request caused many IB owners to suspend their efforts to comply with the 2011 IB MACT limits until they were sure of the exact details of the final limits. Their uncertainty was only heightened by EPA's statements about the numerous reconsideration petitions it had received and the possible revisions it may make in response to those petitions. Almost a year has passed since the rule was published in the Federal Register and IB owners still do not know what limits they will ultimately need to meet. Under these circumstances, it would be unfair to base the date of compliance on the March 21, 2011 publication date.

[Footnotes]

(10) 76 Fed. Reg. 28,662 (May 18, 2011).

(11) Order, *Sierra Club v. Jackson*, Civ. Action No. 11-1278(PLF) (U.S. Dist. Ct. D.C. Jan. 9, 2012).

Response: The EPA thanks the commenter for their support.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 124

Comment: The need for EPA to reset the compliance deadline in this rulemaking is all the more compelling because of some unique circumstances:

EPA administratively stayed the rule on May 18, 2011, two days before the rule was to become effective. See, 76 Fed. Reg. 28662 (May 18, 2011). EPA stayed the rules because it had already determined that significant requirements of the rule needed to be reconsidered and needed additional public comment. Additionally, the Agency received a number of petitions for reconsideration from interested parties, including ACC, asking the Agency to reconsider additional provisions. That stay remained in place until January 9, 2012, when it was vacated by a federal district court. *Sierra Club v. EPA*, No. 11-1278-PLF, 2012 U.S. Dist. LEXIS 2457, (D.D.C. Jan. 9, 2012).

Response: The EPA thanks the commenter for their support.

Commenter Name: Shannon S. Broome

Commenter Affiliation: Auto Industry Forum (AIF)

Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1

Comment Excerpt Number: 7

Comment: EPA proposes to begin the compliance period for affected sources subsequent to publication of the final reconsideration rules. See *CISWI and NHSM Rules Reconsideration Proposal*, 76 Fed. Reg. at 80,465, 80,489; *Boiler MACT Reconsideration Proposal*, 76 Fed. Reg.

at 80,616, 80,628. AIF supports this proposal because it is consistent with EPA's prior actions and it is necessary, in EPA's own words, "to enable facilities sufficient time to install controls and make compliance-related decisions." *Boiler MACT Reconsideration Proposal*, 76 Fed. Reg. at 80,616. Otherwise, affected sources, including those owned and/or operated by AIF member companies, would be left with insufficient time – e.g., less than 2 years under the Boiler MACT – to effectuate compliance with the final reconsideration rules.

Response: The EPA thanks the commenter for their support.

Commenter Name: Shannon S. Broome

Commenter Affiliation: Auto Industry Forum (AIF)

Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1

Comment Excerpt Number: 8

Comment: A. Tying the Compliance Date to Issuance of the Final Reconsideration Rules is Consistent with the Notice of Reconsideration and the Delay Notice: Resulting Uncertainty Limited Affected Sources' Ability to Make Appropriate Selections of Control Technologies and Carry Out Other Compliance Decisions.

As noted above, contemporaneously with the issuance of the three final rules, EPA immediately announced that it was reconsidering fundamental aspects of the final rules. EPA published the same day as the three final rules a Notice of Reconsideration, stating that it was "convening a proceeding for reconsideration of certain portions of [the] emissions standards." *Notice of Reconsideration*, 76 Fed. Reg. at 15,267. The Notice of Reconsideration appropriately recognized that the final rules that were issued required revision due to numerous technical, legal and policy issues that the Agency had not had sufficient time to address in its final rulemakings. By the same token, however, the notice created uncertainty on multiple levels as to the final limits and standards of the Boiler MACT and CISWI Rules.

First, it created uncertainty as to the final composition of "a number of issues" EPA enumerated in the Notice of Reconsideration. Those included fundamental aspects of the Boiler MACT and CISWI Rules, e.g., revisions to the proposed subcategories and to the fuel specification through which gas-fired boilers using a fuel other than natural gas ("NG") can qualify as Gas 1 units in the Major Source Boiler MACT. *See id.* Second, the Notice of Reconsideration created uncertainty as to which other elements not enumerated by EPA would become part of the reconsideration process and how reconsideration might alter the form of those elements as finalized on March 21, 2011. This is because EPA explicitly set forth that it was still "in the process" of determining the full extent of those subjects and that it was committed to including "all additional issues" appropriate for reconsideration, including those raised in any then-prospective petitions for reconsideration. Even to the extent that the Notice of Reconsideration enumerated certain, specific subjects as under reconsideration, it acknowledged that the list was only a portion of the subjects that EPA would ultimately reconsider. *See id.*

Indeed, the scope of the issues that EPA intended to reconsider was not identified until the December 23, 2011, reconsideration proposal, some 9 months later than the publication of the final rule (and a substantial portion of the way into the compliance planning period for affected sources). The Notice of Reconsideration, therefore, literally put affected sources, including those

owned and/or operated by AIF members, on notice that they should not – and, indeed, could not – initiate selections of control technologies or make other compliance decisions because elements of the Boiler MACT and CISWI Rules were subject to change.

The subsequent Delay Notice reinforced the notion that affected sources should postpone the start of internal compliance procedures because it expressly delayed the May 20, 2011, effective date of the Boiler MACT and CISWI Rules, pending the conclusion of judicial review or EPA’s reconsideration process. *See Delay Notice*, 76 Fed. Reg. at 28,662. In the notice, EPA again reiterated that a reconsideration proposal would be forthcoming and that the full extent of the subjects under reconsideration would not be known until issuance of that proposal. *See id.* at 28,663. In the Delay Notice, therefore, EPA induced reasonable reliance on the part of affected sources, including those owned and/or operated by AIF members, to put off making the necessary compliance decisions until further notice.

When weighing various energy strategies to comply with the Boiler MACT, automotive companies face a number of choices. For instance, facilities with coal-fired boilers must decide between several options for meeting the anticipated rules and optimizing energy usage, including adding control equipment to current boilers; converting less efficient steam-powered heaters to NG-fired units; and eliminating coal boilers altogether by either converting them to, or replacing them with, NG-fired units or resource-preserving, landfill gas-fired boilers. The control options associated with the CISWI rule will be even more numerous due to the higher emission restrictions involved. Uncertainty as to the final form of the regulations – including which controls, work practices, and emission standards will apply – inhibits automotive companies from judiciously making these involved energy policy decisions.

Response: The EPA thanks the commenter for their support.

Commenter Name: Shannon S. Broome

Commenter Affiliation: Auto Industry Forum (AIF)

Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1

Comment Excerpt Number: 9

Comment: Once the rules are finalized, implementation of the changes required to achieve compliance can require significant time, beginning with the company’s internal review process. First, the automotive company’s legal and technical personnel must analyze the newly promulgated requirements to determine the best course of action based on the company’s production requirements and its short- and long-term financial situation. After selecting a strategy, the technical staff must compile and present a budget and informational package to facilitate the managerial decision-making process. Next, the automaker’s management must review and approve the compliance strategy. Management approval is followed by compilation of a bid package and vendor list to assist the company in identifying the best equipment and value. The automaker then submits bid packages to identified bidders and, after several rounds of clarifications and negotiations, selects and hires a bidder. It can easily take 6-8 months after the rule is finalized to select a control option and hire an installation contractor, assuming a qualified vendor is available to begin work immediately. Under current regulatory timetables, this would give all affected sources slightly more than a year to design, build, install, and test required control equipment, an insufficient period of time.

Even after a company hires a vendor, it needs additional time to order and install equipment. The length of time depends on the types of equipment or controls chosen, and obtaining certain pieces of equipment sometimes involves significant lead times. In addition, as EPA acknowledges, only a limited number of vendors are qualified to fabricate and install the equipment that the Boiler MACT and CISWI and NHSM Rules will ultimately require.³ A short implementation window would result in flooding these vendors with bid requests and aggressive equipment delivery and installation demands, causing increased wait times and increasing compliance risk for owners and operators. Moreover, as EPA is aware, installation of controls or changes to a process to comply with a rule typically requires air construction permits to be issued under the state implementation plan ("SIP") and revision of Title V operating permits. Construction permit processing times can range from 3 months to over a year and revision of operating permits typically takes no less than 6 months but can take longer.

After the required permits are issued and the requisite equipment is delivered, the speed of installation can depend on the weather in northern climates (where many of AIF members' facilities are located), which inhibits the pouring of concrete foundations depending on the season. A start-up time follows equipment installation and then, generally, the vendor must test the equipment to demonstrate that it meets performance claims. Moreover, as EPA is aware, the rules, once finalized, will require some type of third-party equipment performance testing. Regulated entities will need to select those third-party testing companies by a process similar to vendor-selection process described above and, again, the regulated community would expect shortages of qualified testing vendors in any truncated or expedited rule-implementation window. If, as evaluated through the testing process, the equipment does not meet performance requirements, then it may need additional modification or adjustment.

In the reconsideration proposals, EPA recognizes in general terms the effect of the Notice of Reconsideration and the Delay Notice, describing the "resulting uncertainty" as having "limited the ability of affected sources to begin making appropriate selections of control technologies and other compliance decisions." *E.g., Boiler MACT Reconsideration Proposal*, 76 Fed. Reg. at 80,616. As described above, the compliance process for regulated entities like facilities owned and/or operated by AIF members is protracted and involves many interconnected steps. Given that the regulated community cannot begin the compliance process without knowing the final contours of the rules, any delay in EPA finalizing the Boiler MACT and CISWI Rules necessitates a corresponding delay in the beginning of the compliance period. Otherwise, affected sources, including those owned and/or operated by AIF members, will have insufficient time to comply. Therefore, AIF supports EPA's proposal for the compliance period to begin 60 days after it publishes the final reconsideration rules.

[Footnote 3: In the Boiler MACT Reconsideration Proposal, EPA notes that, even under the statutory maximum of 3 years, the availability of control equipment and vendors to facilitate installation of control technologies is likely to pose a problem, given the thousands of facilities across multiple, diverse industries that will become subject to the final reconsideration rules. *See Boiler MACT Reconsideration Proposal*, 76 Fed. Reg. at 80,616. The potential scarcity in availability of equipment and vendors promises to be exacerbated, as EPA recognizes, by the "large number of units requiring controls in conjunction with the parallel rulemaking for electric generating units that will require controls from many of the same vendors." *Id.*]

Response: The EPA thanks the commenter for their support.

Commenter Name: Shannon S. Broome
Commenter Affiliation: Auto Industry Forum (AIF)
Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1
Comment Excerpt Number: 10

Comment: EPA's Compliance Date Approach is also Consistent with the Fact that EPA Has Not Yet Finalized the Reconsideration Proposals: Until Then, EPA Will Not Resolve the Persistent Uncertainty as to the Content of the Final Rules.

As EPA acknowledges, even after issuance of the reconsideration proposals, affected sources' uncertainty as to the final form of the Boiler MACT and CISWI Rules persists because the reconsideration proposals put forward a number of substantive revisions to the definitions, subcategories, emission limits, work practice standards and other components of the rules. *See CISWI and NHSM Rules Reconsideration Proposal*, 76 Fed. Reg. at 80,465; *Boiler MACT Reconsideration Proposal*, 76 Fed. Reg. at 80,616. In the Boiler MACT Reconsideration Proposal, for example, EPA "proposed changes to emission limits for units in *every* subcategory." *Boiler MACT Reconsideration Proposal*, 76 Fed. Reg. at 80,616 (emphasis added). Revision to emission limits and standards across the subcategories will trigger different compliance responses and control selection than would have flowed from the final rules of March 21, 2011. Those proposed changes, coupled, for example, with the shift to work practice standards for dioxin/furan emissions for *all* subcategories, significantly impacts the ability of affected sources, including those owned and/or operated by AIF members, to develop and decide upon final compliance strategies while the reconsideration process remains ongoing. *See id.* As EPA notes, facilities must design emission controls to work properly when operated together, so they cannot initiate appropriate design of those controls (and make corresponding compliance decisions) until the final limits and standards are known and fixed. *See id.*

The fact that the Boiler MACT and CISWI and NHSM Rules all simultaneously remain in development adds a special level of complication to system analysis prior to the finalized rules. For example, in one process, a company must analyze a system to evaluate which materials the NHSM Rule might be interpreted as a "solid waste." This determination will dictate whether the equipment must ultimately meet the Boiler MACT or the CISWI Rule. In the case of the CISWI Rule, a particular process would likely require addition of an afterburner or recuperative oxidizer, selective catalytic reduction ("SCR"), a scrubber, activated carbon injection and a baghouse. If the material is considered a fuel and not subject to CISWI, however, it would have to meet the Boiler MACT requirements, which would likely involve only a scrubber and a baghouse. Moreover, uncertainty regarding the final limits required by the rule complicates decisions on the process order of the equipment layout. Determination of the final pollutant emission limits dictates, for instance, whether to use a SCR and spray dryer combination versus a multi-pollutant, Tri-NO_x system followed by an acid gas scrubber. The regulated community, including AIF members, simply cannot make these decisions until EPA finalizes the reconsideration proposals. Therefore, such persistent uncertainty delays the start of the implementation process.

Once EPA finalizes the Boiler MACT and CISWI Rules, the compliance strategy process for affected sources, including those owned and/or operated by AIF members, must begin anew. As EPA does not expect to finalize the reconsideration proposals until later this Spring, maintaining

the original compliance dates would provide affected sources with an insufficient amount of time to meet the standards of the forthcoming final reconsideration rules. For the Boiler MACT, for example, maintaining the original compliance date of March 21, 2014, would effectively provide affected sources with less than 2 years. Even under the maximum time of 3 years from the effective date allotted under Section 112 of the Clean Air Act ("CAA"), with which EPA sought to provide affected sources in the March 21, 2011, final rule, EPA characterized the compliance timetable as "pressing." *Delay Notice*, 76 Fed. Reg. at 28,663. AIF concurs. As EPA suggests in the reconsideration proposals, if the Agency does not key the compliance period to the final reconsideration rules, sources will have insufficient time to achieve compliance. EPA should finalize its proposal to begin the compliance period 60 days after publication of the final reconsideration rules.⁴

[Footnote 4: Consistent with its proposal as to affected sources, EPA proposes to delay the start of the compliance period for new sources until 60 days after publication of the final reconsideration rules. See *CISWI and NHSM Rules Reconsideration Proposal*, 76 Fed. Reg. at 80,465; *Boiler MACT Reconsideration Proposal*, 76 Fed. Reg. at 80,616. AIF supports this proposal for many of the same reasons articulated with respect to affected sources.]

Response: The EPA thanks the commenter for their support.

Commenter Name: Shannon S. Broome

Commenter Affiliation: Auto Industry Forum (AIF)

Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1

Comment Excerpt Number: 11

Comment: EPA Possesses the Authority to Set the Compliance Dates Based on the Effective Date of the Reconsideration Rules.

Section 112(i)(3)(A) of the CAA is the key statutory provision governing EPA's authority to establish compliance dates for emission standards. In pertinent part, it sets forth:

After the effective date of any emissions standards, limitation or regulation ...the Administrator shall establish a compliance date or dates for each category or subcategory of existing sources, which shall provide for compliance *as expeditiously as practicable, but in no event later than 3 years after the effective date of such standard* ...CAA § 112(i)(3)(A); 42 U.S.C. § 7412(i)(3)(A) (emphasis added). The plain language of § 112(i)(3)(A) directs EPA to establish a compliance date "no later than 3 years after the effective date" of any emission standard, limitation, or regulation. Here, consistent with that directive, for the Boiler MACT, EPA initially set a compliance date for the Boiler MACT of March 21, 2014, or 3 years after the March 21, 2011, publication of the final rule in the *Federal Register* and slightly less than 3 years after the initial effective date of May 20, 2011. Now, as discussed above, EPA proposes to start the 3-year compliance period beginning 60 days after publication of the final reconsideration rule. As discussed above, the rationale is that EPA proposes substantial revisions of the reconsideration proposals and that the Notice of Reconsideration, along with the Delay Notice, generated uncertainty as to the final form of the rules throughout the regulatory community. As a result of this process, affected sources have not been able to initiate the compliance process—the composition of the final rule remains unclear and those sources continue to operate in reliance on

EPA's representations that the effect of the Boiler MACT is stayed and that the 3-year compliance period will begin only after publication of the final reconsideration rule.

Looking first to the statute, while Section 112 provides that emission standards or other regulations promulgated under Section 112(d) "shall be effective upon promulgation," CAA § 112(d)(10); 42 U.S.C. § 7412(d)(10),⁵ the statute does not address what that means in the current context, in which EPA is revising – and doing so in a substantial way – a previously promulgated standard and promulgating a *new* standard. It does not state, when it directs EPA to establish a compliance date within 3 years of the "effective date," whether the effective date must be the date on which the emission standard is effective as first promulgated or as subsequently revised on reconsideration. EPA's final action will essentially act as a *new issuance* of an emissions standard, which itself will have a new "effective date." Under Section 112(i), therefore, EPA may, indeed must, determine the compliance date for existing sources based on that effective date.

[Footnote 5: Note that the Congressional Review Act had the effect of delaying this date by 60 days to allow time for congressional review. 5 U.S.C. § 801(a)(3)]

Response: The EPA thanks the commenter for their support.

Commenter Name: Shannon S. Broome

Commenter Affiliation: Auto Industry Forum (AIF)

Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1

Comment Excerpt Number: 12

Comment: Case law does not prohibit the Agency from taking this approach. The D.C. Circuit has not squarely taken up this issue; instead, it has merely considered EPA's authority to extend compliance deadlines beyond the 3-year statutory maximum. *See NRDC v. EPA*, 489 F.3d 1364, 1373-74 (D.C. Cir. 2007). Specifically, in *NRDC*, the D.C. Circuit vacated a portion of an EPA rulemaking that had *extended* the original compliance date by one year for sources in the low-risk subcategory of the MACT for plywood and composite wood products (40 C.F.R. § 63, Subpart DDDD). *See id.* The court held that EPA had not relied on Section 112(i)(3)(B) for this extension – the provision that addresses *extensions* – but instead had relied on Section 112(i)(3)(A), which addresses the compliance period keyed to the effective date of an emissions standard. *See id.* In *NRDC*, according to the court's holding, EPA went astray when it promulgated emission standards in 2004, setting a compliance deadline for 3 years later (2007) and *then* endeavored to *extend* the compliance deadline for 2008 – or 4 years after the effective date – based on a finalized reconsideration proposal but without undergoing the case-by-case extension process provided in Section 112(i)(3)(B). *See id.*

By contrast, here EPA is resetting the clock on the emissions standard because it is re-promulgating the action. In the case of the Boiler MACT, for example, EPA proposes the following amendments to § 63.7495, concerning "When do I have to comply with this subpart?":

(a) If you have a new or reconstructed boiler or process heater, you must comply with this subpart by [DATE 60 DAYS AFTER THE FINAL RULES IS PUBLISHED IN THE *Federal Register*] or upon startup of your boiler or process heater, whichever is later.

(b) If you have an existing boiler or process heater, you must comply with this subpart no later than [DATE 3 YEARS AFTER PUBLICATION OF THE FINAL RULE IN THE *Federal Register*], except as provided in § 63.6(i).

Boiler MACT Reconsideration Proposal, 76 Fed. Reg. at 80,628 (formatting in original). The reconsideration proposal, then, avoids the problem created by EPA's approach to extending the compliance deadlines in *NRDC* because it does not stretch the compliance deadlines beyond 3 years after the effective date. Instead, this proposal sets a new effective date of 60 days after publication of the final reconsideration rule and then fixes the compliance deadline to 3 years after that date. As a corollary, it fixes the date on which new or reconstructed sources must comply with the emission standards as 60 days after the final reconsideration rule, which adheres to the mandates of § 112(i). EPA's proposal, therefore, is consistent with the holding of *NRDC* and the statutory directive of § 112(i)(c)(A). EPA has the legal authority to finalize the proposed regulations as to the compliance period 6

[Footnote 6: In the alternative, at a minimum, EPA could invoke authority under Section 112(i)(3)(B) and create a streamlined case-by-case process for granting extensions of one year.]

Response: The EPA thanks the commenter for their support.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 2

Comment: EPA proposes to reset the compliance date for existing sources to 3 years after publication of the final reconsideration rule and for new sources, to the later of 60 days after publication of the final reconsideration rule or startup. 76 Fed. Reg. 80605. Sources need a substantial period to come into compliance and CIBO strongly supports resetting the dates. Internal planning for compliance with major rules requires involvement of personnel at all levels of the company, and in the case of this major rule, will require major capital projects at many facilities covered by this rule. CIBO has commented in earlier comments at length on the need for sufficient time for the complex undertaking of retrofitting a major boiler facility, including compliance planning, engineering design, capital approval, equipment purchase, installation and testing, all in advance of the compliance date.

Here, because EPA issued an immediate Notice of Reconsideration of the rule, sources understood as of the publication of the March 2011 Final Rule that there would be amendments to the rule that could very well alter compliance strategies. At the time, it was unclear whether the rule would change considerably from the final version, and with respect to which sources and emission limits. One significant element of the BMACT rule that would clearly undergo change, based in part on EPA's flawed or incomplete data, was the inventory of units in some subcategories, and their emission limits. In addition, several clear problems in the March 2011 Final NHSM rule made it clear that the definitions of NHSM and fuel were highly likely to be amended. Changes to correct data and likely revisions to the fuel definition would clearly affect the inventories of units in boiler subcategories and therefore floor calculations and emission limits. Under those circumstances, it would not have been rational for sources to develop

compliance strategies and begin the complicated, costly process of compliance with a rule that EPA had announced would be changed.

[Footnote 6:See EPA Letter to Sen. Wyden, Jan. 18, 2012. Appendix A of submittal.]

[Footnote 7:See EPA No Action Assurance letter, Feb 7, 2012. Appendix B of submittal.]

Response: The EPA thanks the commenter for their support.

Commenter Name: Russell A. Wozniak

Commenter Affiliation: The Dow Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3449-A1

Comment Excerpt Number: 1

Comment: Dow supports EPA's proposal to establish the compliance date for existing sources three years after publication of the final amended rule in the Federal Register.

EPA's proposed amendments during this reconsideration will impact the detailed compliance requirements for existing sources. Therefore, allowing existing sources a full three year period, except as provided in 40 CFR 63.6(e)(i), to comply with all of the requirements in the final rule is reasonable and supported by Dow.

Response: The EPA thanks the commenter for their support.

Commenter Name: Melvin E. Keener

Commenter Affiliation: Coalition for Responsible Waste Incineration (CRWI)

Document Control Number: EPA-HQ-OAR-2002-0058-3454-A1

Comment Excerpt Number: 18

Comment: CRWI supports resetting the compliance date to 3 years after publication of the final reconsideration.

CRWI supports EPA's decision to reset the compliance date to three years after the publication of the reconsideration final rule. EPA has proposed changes to standards for every subcategory. Once final, each facility will need the three years to revise their strategies for coming into compliance.

Response: The EPA thanks the commenter for their support.

Commenter Name: John C. Hendricks

Commenter Affiliation: American Electric Power (AEP)

Document Control Number: EPA-HQ-OAR-2002-0058-3455-A1

Comment Excerpt Number: 3

Comment: American Electric Power (AEP) agrees with EPA's proposal to extend the compliance date for this rule to 3-years after the publication of the final version of this reconsideration of the IB Boiler MACT Rule. Allowing this compliance schedule will provide

additional time to the facility owners to make the needed enhancements and installations needed to meet the requirements in this rule.

Response: The EPA thanks the commenter for their support.

Commenter Name: Claudia M. O'Brien, Latham & Watkins LLP

Commenter Affiliation: JELD-WEN, inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3485-A1

Comment Excerpt Number: 4

Comment: EPA has proposed to extend the compliance deadlines for existing sources to three years after publication of the final Boiler MACT reconsideration rule. JELD-WEN strongly supports this extension of the compliance deadline as the extension is both necessary and consistent with EPA's statutory authority.

JELD-WEN agrees with EPA that the deadline extension is required to enable sources to make compliance-related decisions and to install controls if needed. As EPA explained, the Boiler MACT reconsideration "proposed changes to the emission limits for units in every subcategory." From a practical standpoint, the different standards may change the type of controls needed for compliance or the design of the controls. EPA also rightly noted that the uncertainty caused by the reconsideration limited sources' ability to prepare for compliance. Leaving the existing compliance deadline in place from the March 2011 final rule would provide less than two years for sources to meet the standards, and sources still do not know what the *final* standards will be until the final reconsideration rule is published.

Response: The EPA thanks the commenter for their support.

Commenter Name: N.W. Bernstein & Associates, LLC

Commenter Affiliation: Eco Power Solutions (USA) Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3499-A1

Comment Excerpt Number: 1

Comment: The most important part of EPA's proposed HAPs rule revision for major source industrial boilers, and also in a sense the most legally challenged portion of the proposed reconsideration and revision of the Boiler Rule, is the "reset" of the schedule for compliance. Without a "reset," compliance must be achieved within three years from the date the original Boiler Rule was originally effective, May 20, 2011 (i.e. May 2014 – slightly more than two years from now), plus one year for source by source extensions (i.e. May 2015 at the latest).² It is critically important that the compliance date be reset not only for the reasons given by EPA in its proposed reconsideration of the original Boiler Rule, but additionally because without a reset, it will be virtually impossible for operators of industrial boilers that are major sources to achieve compliance without rushing to install conventional technology without any realistic opportunity to evaluate innovative multi-pollutant removal technology such as Eco Power's COMPLY 2000® and other new technologies.

[Footnote]

(2) The original Boiler Rule was published in the Federal Register on March 21, 2011, but did not become effective until May 20, 2011. 76 Fed. Reg. No. 54 at 14608.

Response: The EPA thanks the commenter for their support.

Commenter Name: N.W. Bernstein & Associates, LLC

Commenter Affiliation: Eco Power Solutions (USA) Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3499-A1

Comment Excerpt Number: 2

Comment: EPA has proposed to “reset” the compliance date for existing sources to the date three years after the date effective date of the final reconsideration of the Boiler Rule. 76 Fed. Reg. at 80,605, 80,616-17. EPA specifically requested comment on the proposed changes to the compliance dates. *Id.*, at 80,617. Part of the rationale provided by EPA for doing the “reset” is that when EPA announced its reconsideration and its attempted postponement of the effective date, it indicated that requirements were to change significantly and that the resulting uncertainty has limited the ability of affected sources to begin making selection of control technologies and compliance decisions. Moreover, even if significant changes were not being proposed, “an extended compliance date would likely be necessary to provide enough time for facilities to achieve compliance.” *Id.*, at 80,616.³

[Footnote]

(3) EPA also noted that the availability of control equipment and vendors to install control equipment for boilers is in question due to the demands of the EGU rulemaking which will require controls from many of the same vendors. *Id.*

Response: The EPA thanks the commenter for their support.

Commenter Name: David A. Buff, Golder Associates Inc.

Commenter Affiliation: Florida Sugar Industry (FSI)

Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1

Comment Excerpt Number: 54

Comment: The FSI supports EPA’s proposal to re-set the compliance deadline during the reconsideration process. Affected sources have not been able to begin detailed compliance planning because the final Boiler MACT Rule requirements are still uncertain. It will be extraordinarily difficult – if not impossible – for all of the entities with existing boilers to make the changes necessary to comply with the Boiler MACT rule in three years. The normally Herculean task of performing a boiler retrofit in three years will be made virtually impossible by the enormous competition for critical resources and the likely gridlock in many state permitting processes that the broad application of this rule and other new rules for utility boilers will create. Many boiler owners will be unable to secure equipment and assistance, as well as obtain the state/local permits needed to retrofit their units, within three years. The FSI sugar mills are acutely affected by these rules because each mill have as many as 6 (six) boilers, all of which must comply with the new EPA requirements by the compliance date. The members of the FSI have been trying to determine what they must do to comply with the Boiler MACT Rule, but it

has been very difficult to move forward with any capital projects because the EPA requirements for industrial boilers, CISWI units, and utility boilers have created a complex set of interrelated requirements and a "moving target" for compliance.

Response: The EPA thanks the commenter for their support.

Commenter Name: James Johnson

Commenter Affiliation: United States Beet Sugar Association (USBSA)

Document Control Number: EPA-HQ-OAR-2002-0058-3508-A1

Comment Excerpt Number: 9

Comment: In the reconsideration of the major source Boiler Rule, EPA proposed to reset the compliance

date for existing sources such that it would reflect a timeline three years after the date of publication of the eventual final rule. USBSA supports EPA's approach for adjusting this compliance deadline. CAA section 112(i)(3) allows for three years for compliance from the effective date of a final rule, and thus a revision to the compliance deadline in the rule is appropriate. There is currently a large amount of uncertainty in the regulated community surrounding the eventual shape of the Boiler Rules, and EPA's approach seeks to provide affected sources with at least the full three years intended by section 112(i)(3). Even with the adjustment to reflect the intent of section 112(i)(3), however, USBSA members will have difficulty meeting the rule's very tight timeframe for compliance.

Response: The EPA thanks the commenter for their support.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 126

Comment: Due to the vacatur of the stay, the regulated community has lost almost a year from the original compliance time frame. If EPA does not reset or extend the compliance date in the final reconsidered boiler major source rule, affected sources will have only about two years to undertake all of the actions and testing required to try to meet the existing compliance deadline. Given the complexity of this rule and all of the necessary actions that thousands of affected sources will have to take, meeting a 2 year compliance deadline is going to be impossible for most sources, even if the final reconsidered rule were to remain unchanged from the March 2011 final rule.

Response: The EPA thanks the commenter for their support.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 127

Comment: Exacerbating the compliance challenges that will be presented in the final reconsidered rule is the fact that EPA is promulgating the first NESHAP rule applicable to EGUs along the same time frame as this rule. As EPA correctly notes, the sheer volume of sources that will need to devise new compliance strategies and install new equipment pursuant to this rulemaking, the CISWI rulemaking, and the EGU rulemaking will outstrip the availability of the vendors who can do this work. 76 Fed. Reg. 80616.

Response: The EPA thanks the commenter for their support.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 18

Comment: EPA proposes to reset the compliance deadline for existing affected sources to three years after the date of publication of the Final Reconsideration Rule in the Federal Register. EPA promulgated a Boiler MACT rule in March 2011 but also announced that it would reconsider certain portions of the rule and then subsequently stayed the effective dates of the rule on May 18, 2011. A recent court decision vacated the stay, resulting in the original compliance timeline of 3 years from March 21, 2011 for existing sources becoming effective again. We support EPA's proposal to re-set the compliance timeline with the reconsideration rule, as affected sources have not had the ability to begin detailed compliance planning because the final requirements are uncertain. EPA recognizes in its January 18, 2012 letter from Administrator Lisa Jackson to Senator Ron Wyden that industry needs sufficient time to comply with these new standards.

Response: The EPA thanks the commenter for their support.

Commenter Name: Richard Krock

Commenter Affiliation: The Vinyl Institute

Document Control Number: EPA-HQ-OAR-2002-0058-3526-A1

Comment Excerpt Number: 12

Comment: EPA Should Extend the Compliance Deadline to Three Years After Promulgation of the Final Boiler MACT

On January 9, the U.S. District Court for the District of Columbia vacated EPA's May 18, 2011, stay of the Boiler MACT.¹⁷ This vacatur restored the compliance deadlines for affected sources set in the final Boiler MACT promulgated on March 21, 2011. These included notification requirements under the General Provisions in 40 C.F.R. Part 63, as well as the three-year deadline for complying with emission standards. The former is addressed in the proposed rule, which states that the notification requirements of the General Provisions must be met no later than 120 calendar days after the final rule is published in the Federal Register.¹⁸ This revision is necessary because EPA has added additional subcategories and clarified exemptions, and as a result the information that must be provided in the notification, namely "the types of emission points within the affected source subject to the relevant standard and types of hazardous air pollutants emitted," has changed.

[Footnotes]

(17) *Sierra Club v. Jackson*, No. 11-1278 (D.D.C. Jan. 9, 2012).

(18) 76 Fed. Reg. 80,646 (to be codified at 40 C.F.R. § 63.7545(b)).

Response: The EPA thanks the commenter for their support.

Commenter Name: Richard Krock

Commenter Affiliation: The Vinyl Institute

Document Control Number: EPA-HQ-OAR-2002-0058-3526-A1

Comment Excerpt Number: 13

Comment: EPA stated in the proposed rule that existing sources must comply with the Boiler MACT no later than three years after the publication of the final reconsidered rule.²⁰ The VI fully supports this updated compliance date. The reconsideration, stay, and subsequent vacatur have created significant regulatory uncertainty for affected sources, necessitating a "reset" of the compliance clock to allow existing sources the full statutory time to make necessary investments in emission controls. EPA is authorized to set the compliance date up to three years after the effective date of an emission standard.²¹ EPA has proposed revised emission standards for most but not all subcategories. Given that emission control technology must be designed as a whole, to address all regulated HAPs, EPA's revision of some emission limits has effectively changed the emission standards for all sources and subcategories. EPA therefore correctly set the compliance date for all emission standards to three years from the date of the final reconsidered Boiler MACT.

[Footnotes]

(21) 42 U.S.C. § 7412(i)(3)(A). *See also* *NRDC v. EPA*, 489 F.3d 1364, 1373-74 (D.C. Cir. 2007).

Response: The EPA thanks the commenter for their support.

Commenter Name: Vickie Woods

Commenter Affiliation: Division of Air Quality, North Carolina Department of Environment and Natural Resources (NCDENR)

Document Control Number: EPA-HQ-OAR-2002-0058-3663-A2

Comment Excerpt Number: 25

Comment: EPA is proposing compliance date for existing sources that is 3-years after date of publication of the final reconsideration rule.

NC DAQ supports this compliance date given the issues associated with this rule.

Response: The EPA thanks the commenter for their support.

Commenter Name: Bill Lane

Commenter Affiliation: American Home Furnishings Alliance (AHFA)

Document Control Number: EPA-HQ-OAR-2002-0058-3676-A2

Comment Excerpt Number: 8

Comment: AHFA strongly supports EPA’s decision to reset the compliance date for existing source boilers at three years after promulgation of a final reconsideration rule, rather than the current compliance date of March 21, 2014. A minimum of three years will be needed for our members to comply with the requirements of the final Boiler MACT rule. Even with three years notice, there is considerable uncertainty about the ability of boiler industry suppliers to meet demand for tuneups and control equipment engineering, installation, and testing.

Response: The EPA thanks the commenter for their support.

Commenter Name: N.W. Bernstein & Associates, LLC

Commenter Affiliation: Eco Power Solutions (USA) Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3499-A1

Comment Excerpt Number: 4

Comment: In *Natural Res. Def. Council v. EPA*, 489 F.3d 1363 (D.C.Cir. 2007), the D.C. Circuit rejected an effort by EPA to extend by one year the compliance date for emissions standards established in 2004 in light of what EPA characterized as substantial changes made in the 2006 version of the rule at issue. The Court relied on the plain language of the CAA, Subsection 112(i)(3)(A), that after the effective date of any [Section 112] emission standard, limitation or regulation, the Administrator shall establish a compliance date or dates: “which shall provide for compliance as expeditiously as practical but in no event later than 3 years after the effective date of *such standard*” *Id.*, at 1373 (emphasis in original).

The D.C. Circuit read the phrase “such standard” as meaning the effective date of a Section 112 emission standard. Accordingly, it rejected EPA’s argument that extensions of compliance should be allowed when EPA determines that substantial changes and amendments to the rule have been made. *Id.*, at 1374.

The reasoning of *Natural Res. Def. Council* was followed in *Sierra Club v. EPA*, 551 F.3d 1019 (D.C. Cir. 2008). In dealing with EPA’s attempt to exempt major sources from compliance with Section 112 emissions standards during startups, shutdowns, and malfunctions, the Court rejected EPA’s claim that it retained discretion: where “Congress explicitly enumerate[d] certain exceptions to a general prohibition, additional exceptions are not to be implied, in the absence of the contrary legislative intent.” *Id.*, at 1028 (quoting *Natural Res. Def. Council*, 489 F.3d at 1374).

Finally, the specific and somewhat limited rationale for the “reset” of the compliance deadlines as set forth by EPA in the preamble to the proposed revision to the original Boiler Rule is virtually the same rationale that was recently rejected in *Sierra Club v. Jackson*, Case No. 11-1278, 2012 WL 34509, at *16-20 (D.C. Cir. Jan 9, 2012). Accordingly, it is likely that environmental groups will contend that EPA’s actions in resetting the time clock are both unauthorized under the CAA and arbitrary and capricious under the APA.

Response: EPA thanks the commenter for their support of the reset of three years from publication of the final rule for existing sources. The three years from this final action on

reconsideration is "as expeditiously as practicable," because the sources are getting more stringent limits. Each of the subcategories with emission limits have at least one more stringent limit that will drive different control measures compared to the March 2011 final rule and the facilities will need time to finance and develop their control measures.

Commenter Name: Claudia M. O'Brien, Latham & Watkins LLP

Commenter Affiliation: JELD-WEN, inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3485-A1

Comment Excerpt Number: 5

Comment: The CAA permits EPA to extend the compliance deadline as it has proposed here. Section 112(i)(3)(A) requires EPA, upon promulgating "any emissions standard, limitation," to set a compliance schedule for any category or subcategory of existing sources, and mandates that the compliance deadline may be "no... later than 3 years after the effective date of such standard."¹⁸ Therefore, EPA's proposal of requiring existing sources to comply with the Boiler MACT within three years after the final rule is published complies with the statute.

The proposed extension here is distinguishable from the extension that the D.C. Circuit invalidated in *Natural Resources Defense Council v. EPA*,¹⁹ for EPA's wood products MACT rule. In that case, EPA finalized the wood products MACT in 2004, but amended the rule in 2006 to change definitions, "procedures for the low-risk demonstration process, and other permitting and timing issues" and to reset the compliance date from October 1, 2007 (within three years of the initial rule) to October 1, 2008? The court found that this compliance extension violated EPA's statutory authority because "the trigger for the three-year compliance period" is the effective date of the emissions standards-not the effective date of modifications to regulatory definitions, procedures, permitting, etc? That is not the case here. In the Boiler MACT reconsideration, EPA has proposed new emissions limitations and replaced dioxin/furan limitations with work practice standards for every source. As such, JELD-WEN strongly supports EPA's proposed extension to the compliance deadline.

[Footnote 18: 42 U.S.C. § 7412(i)(3)(A).]

[Footnote 19: 489 F.3d 1364 (D.C. Cir. 2007).]

[Footnote 20: 489 F.3d 1364 (D.C. Cir. 2007) at 1370.]

[Footnote 21: 489 F.3d 1364 (D.C. Cir. 2007) at 1373-74.]

Response: The EPA thanks the commenter for their support.

Commenter Name: Mary Sullivan Douglas

Commenter Affiliation: National Association of Clean Air Agencies (NACAA)

Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1

Comment Excerpt Number: 44

Comment: EPA has proposed to extend the compliance date for all sources and all limits. We agree that such an extension is appropriate where more stringent limits are imposed following reconsideration, since sources should not have to comply with standards that ratchet in

stringency after only one year. We note that EPA's stay pending reconsideration has been rejected by the Court and caution that an effort to provide an extended compliance deadline for sources whose emission limits are not made more stringent may invite litigation that affects an extension for sources facing more stringent limits. We further note that the CAA provides the option of an additional year for compliance where a source demonstrates a need for more time.

Response: The EPA thanks the commenter for their support to reset the compliance date three years from publication of this final rule for existing sources having more stringent standards. The commenter recommended caution against compliance deadlines for sources where emission limits are not more stringent. We agree that the three years from the final action on reconsideration is "as expeditiously as practicable," for the sources for which the numeric emissions limits are more stringent than in the March 2011 final rule. All of the subcategories that are subject to emission limits have at least 1 HAP limit (most have 2) that is more stringent as compared to the March 2011 final rule. Also, in this final rule, three of the March 2011 subcategories have split: biomass stoker subcategory split into wet biomass stoker and dry biomass stoker; biomass suspension subcategory split into suspension grate and suspension burner; and liquid subcategory split into heavy liquid and light liquid. All the subcategories subject to emission limits will be getting at least one more stringent limit compared to the March 2011 final rule and given that emission control technology is typically designed as a whole the facilities will need time to finance and develop their control measures. Thus, they need the full three years.

The emissions standards for the Gas 1 subcategory and for units less than 10 million Btu/hr are not more stringent than the March 2011 final rule. However, the reconsideration, stay, and subsequent vacatur have created significant regulatory uncertainty for affected facilities and that given that affected facilities have affected units in other subcategories in addition to Gas 1 and small units and that a facility's compliance strategy is generally designed as a whole, we are resetting the compliance date for existing units for all requirements.

Commenter Name: N.W. Bernstein & Associates, LLC
Commenter Affiliation: Eco Power Solutions (USA) Corporation
Document Control Number: EPA-HQ-OAR-2002-0058-3499-A1
Comment Excerpt Number: 5

Comment: EPA should properly set the compliance schedule in a way that is consistent with the CAA and the APA. EPA should exercise its authority under the APA, 5 U.S.C. §§ 551(5) and 553(c), to propose to "repeal" the original Boiler Rule promulgated on March 21, 2011 in its entirety, and then after receipt of comments on the proposal, proceed to repeal the original Boiler Rule in its entirety. Instead of reconsidering that rule, EPA should promulgate a new final Boiler Rule containing the corrected standards and containing compliance deadlines consistent with the three plus one year provisions of Section 112 of the CAA, starting on the effective date of the new rule.⁴

It is certainly true that,

"When an agency acts to rescind a standard it previously adopted, a reviewing court will subject that rescission to the same level of scrutiny applicable to the agency's original promulgation."

Association of Public-Safety Comm. Officials-Int'l, Inc. v. F.C.C., 76 F.3d 395, 398 (D.C. Cir.1996) (citing *Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 41, 103 S.Ct. 2856 (1983)).

To justify the rescission of the original Boiler Rule in its entirety and the promulgation of a new Boiler Rule, EPA needs to say more than simply “industry needs the time.” It needs also to point to societal benefits that will be lost if EPA does not act to rescind the original Boiler Rule and promulgate a new rule. A principal societal benefit of that approach will be the restoration of the opportunity that would otherwise be lost for the deployment of innovative multi-pollutant removal technologies that have numerous benefits. In capital-intensive industries involving long lead times, industrial companies operating major sources need time to evaluate new technology. They need also to try to adapt strategies that reflect the need to control multiple pollutants being covered by different EPA rulemakings.

[Footnote]

(4) What EPA should do is not to attempt to “postpone” or “reset” compliance dates that were triggered by the original promulgation of the Boiler Rule on March 21, 2011, as part of any “reconsideration” of certain provisions of final rule. Attempting to do so will likely run afoul of the plain language of the CAA and the above noted D.C. Circuit cases.

Response: The boiler MACT was issued pursuant to section 307(d) of the Clean Air Act to satisfy certain Agency obligations under section 112 of the Act. Section 307(d) expressly provides that sections 553 through 557 of the APA shall not apply to section 307(d) actions except as specifically provided in section 307(d). Further, the commenter points to nothing in section 551(5) of the APA (which simply defines the term “rule making”) or 553(c) (which addresses public participation requirements for APA rules) relevant to “repealing” the boiler MACT, and EPA sees nothing in those sections –even if they did apply to CAA section 307(d) actions – that would be relevant. Further, the commenter provides no explanation for its view that revising the compliance deadline as part of today’s action is inconsistent with the Act or with DC Circuit caselaw. As explained above, EPA is establishing a compliance date for existing sources that requires compliance as expeditiously as practicable and is consistent with the requirements of section 112(i)(3).

Commenter Name: David Gardiner

Commenter Affiliation: The Alliance for Industrial Efficiency

Document Control Number: EPA-HQ-OAR-2002-0058-3683-A2

Comment Excerpt Number: 2

Comment: We Commend EPA for Recognizing that Coal-Fired Facilities Seeking to Incorporate Clean and Efficient Combined Heat and Power or Waste Heat Recovery Are Eligible for a One-Year Compliance Extension.

CHP and WHR developers and environmental engineering firms have worried that three years would not be sufficient time for boiler owners to design, permit and install a CHP or WHR system. EPA regulations clearly recognize the potential delays for boiler owners seeking to install add-on pollution controls, allowing those boiler owners to petition for a one-year extension if necessary for the installation of such controls.³ In the re-proposed rule, EPA

clarifies that the installation of a CHP or WHR system could, in fact, support a request for a compliance extension. We thank EPA for this clarification and believe that treating CHP and WHR as controls in this manner may encourage facilities to pursue these technologies, which will ultimately lead to greater fuel savings and emission reductions. We look forward to working with EPA and with regulated entities to alert them to this provision and encourage them to pursue industrial efficiency projects.

[Footnote 3: See 40 CFR 63.6 (Authorizing the Administrator or delegated state authority to “grant an extension allowing the source up to 1 additional year to comply with the standard, if such additional period is necessary for the installation of controls”).]

Response: The EPA thanks the commenter for their support for clarifying that Combined Heat and Power (CHP) and Waste Heat Recovery (WHR) are eligible for a 1-year extension.

Commenter Name: Lisa Jacobson

Commenter Affiliation: Business Council for Sustainable Energy (BCSE)

Document Control Number: EPA-HQ-OAR-2002-0058-3497-A1

Comment Excerpt Number: 2

Comment: *Clarifying that coal-fired facilities seeking to incorporate clean and efficient combined heat and power (CHP) or waste heat recovery (WHR) are eligible for a one-year compliance extension.* CHP and WHR developers and environmental engineering firms have worried that three years would not be sufficient time for boiler owners to design, permit and install a CHP or WHR system. EPA regulations clearly recognize the potential delays for boiler owners seeking to install add-on pollution controls, allowing those boiler owners to petition for a one-year extension if necessary for the installation of such controls.² In the re-proposed rule, EPA clarifies that the installation of a CHP or WHR system could, in fact, support a compliance extension request.³ We thank EPA for this clarification and believe that treating CHP and WHR as controls in this manner may encourage facilities to pursue these technologies, which will ultimately lead to greater fuel savings and emission reductions.

[Footnote 2: See 40 CFR 63.6 (Authorizing the Administrator or delegated state authority to “grant an extension allowing the source up to 1 additional year to comply with the standard, if such additional period is necessary for the installation of controls”).]

[Footnote 3: See U.S. EPA, 76 Fed. Reg. 80598, 80671, “National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters,” Dec. 23, 2011 (Table 10 to Subpart DDDDD of Part 63) (“Facilities may request extensions of compliance for the installation of combined heat and power or waste heat recovery as a means of complying with this subpart”).]

Response: The EPA thanks the commenter for their support.

Commenter Name: Shawn Good

Commenter Affiliation: Pennsylvania Chamber of Business and Industry

Document Control Number: EPA-HQ-OAR-2002-0058-3671-A2

Comment Excerpt Number: 1

Comment: Compliance timetables and non-enforcement of violations of the March 2011 rules should be clarified in light of the vacated stay.

The recently vacated stay of the effective date for the initial final Major Source ICI Boiler Rule and CISWI Rule has introduced much uncertainty for businesses that are now faced with compliance deadlines, some already past, which cannot be met. In the revised final rule, EPA should clarify that compliance timetables will be based on the effective date established by the re-promulgated final rules, rather than the initial March 2011 promulgation date, meaning compliance deadlines will fall in 2015 (assuming a 2012 re-promulgation effective date) instead of 2014. Furthermore, as already indicated in the February 7, 2012 "no action" memo from Gina McCarthy at EPA, the revised final rule should reaffirm that technical violations of the March 2011 regulations will not be subject to enforcement.

Response: In the final rule, we are finalizing the proposed resetting of the compliance date to three years after publication of this reconsideration final rule.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 1

Comment: EPA should stay the effect of the March 2011 Boiler MACT rule and issue additional guidance or no enforcement assurance to address compliance exposure faced by sources during the period before EPA issues a Final Reconsideration Rule.

EPA had delayed the effective dates of the March 2011 Final Boiler MACT and CISWI rules.⁴ However, on January 9, 2012, the U.S. District Court for the District of Columbia vacated EPA's Delay Notices,⁵ and any compliance obligations for sources covered by the Boiler MACT and CISWI rules became effective immediately. EPA recognized that the vacatur triggered some compliance obligations, and on January 18, 2012 EPA announced in a letter to Senator Wyden⁶ its plan to address the implications of the vacatur. Then on February 7, 2012, EPA issued a No Action Assurance memorandum that addresses some – but not all – of the implications of the vacatur.⁷ EPA's memorandum assures sources in a limited scope of circumstances that their failure to have met a deadline to file an initial notification would not be the basis of an enforcement action brought by EPA, given that the deadline fell during the period when the Boiler MACT and CISWI rules were not in effect. In the letter to Senator Wyden, EPA asserts that for any "permitting or compliance challenges" arising from the vacatur, EPA will issue a stay for 90 days or longer, and in the event of lawsuits arising from the vacatur, EPA is "confident" that it has the legal tools to address those matters. Notwithstanding its assurances, EPA's memorandum does not alleviate many pressing continuing compliance concerns faced by sources because the rules remain in effect.

[Footnote 5: Opinion, *Sierra Club v. EPA*, No. 11-1278 (DDC Jan. 9, 2012).]

Response: This comment is in regards to the No Action Assurance letter issued by the EPA and is out-of-scope with the proposed rulemaking.

Commenter Name: Chris M. Hobson
Commenter Affiliation: Southern Company
Document Control Number: EPA-HQ-OAR-2002-0058-3520-A1
Comment Excerpt Number: 15

Comment: Some fossil fuel fired electric generating units may convert to biomass fired electric generating units after the compliance date for existing sources. Thus the deadline for completing the initial compliance demonstration for these existing sources should be no later than 180 days after becoming an affected source, not 180 days after the compliance date specified in 63.7495.

Response: We agree with the commenter that the proposed reconsideration rule does not address the situation when a fossil fuel-fired utility boiler switches from coal to biomass and switches from being subject to MATS to being subject to Boiler MACT. In the final rule, we have added subparagraphs to §63.7490, §63.7495, and §63.7510 to clarify that the deadline for completing the initial compliance demonstration for existing EGU sources to be no later than 180 days after becoming an affected source under the Boiler MACT.

Commenter Name: Bart Sponsellar
Commenter Affiliation: Wisconsin Department of Natural Resources (DNR)
Document Control Number: EPA-HQ-OAR-2002-0058-3527-A1
Comment Excerpt Number: 3

Comment: We believe that compliance dates for all requirements, including tune-ups, should be no sooner than March 21, 2014 — the maximum time allowed under the Clean Air Act. EPA needs to consider that sources will be planning and applying resources to fulfill multiple requirements. Under these circumstances sources need flexibility to determine where best to apply resources, whether for emission limitations, tune-ups, or energy assessments. The rule should not mandate the priority or approach in reducing emissions. EPA must also realize that the same equipment providers and vendors will be needed by sources affected by either the major or area source rules as well as the EGU boiler MACT. We also believe EPA has flexibility to provide an additional year for performing energy assessments because implementation is voluntary. If it aids in compliance, a source will pursue energy improvement measures prior to March 21, 2014.

Response: The commenter is referring to the proposed change to the compliance date for conducting the tune-up in the Boiler Area Source Rule, subpart JJJJJ, which is out-of-scope for this rulemaking. We disagree with the commenter that the EPA has the flexibility to provide an extra year for performing the energy assessments. Section 112(i)(3)(B) of the Clean Air Act clearly state that the Administrator "may issue a permit that grants an extension permitting an existing source up to 1 additional year to comply with standards under subsection (d) if such additional period is necessary for the installation of controls."

Commenter Name: John M. Cullen
Commenter Affiliation: Masco Corporation
Document Control Number: EPA-HQ-OAR-2002-0058-3661-A2
Comment Excerpt Number: 5

Comment: EPA has proposed to extend the deadline from one year to two years from the original promulgation date (March 21, 2011) for sources to complete initial compliance demonstrations of the tune-up requirements for regulated boilers, so that the initial compliance demonstration date for a boiler tune-up would be March 21, 2013. EPA also seeks comment on whether to extend the initial compliance date for an additional year, or three years from promulgation (i.e. March 21, 2014). Masco supports extending the initial compliance date for the additional year. Such a change would harmonize the compliance dates for existing sources. The additional time would also serve to ensure that regulated sources are provided with adequate time to retain contractors for boiler tune-ups, and implement recordkeeping, personnel training and compliance programs to comply with the rule

Response: The commenter is referring to the proposed change to the compliance date in the Boiler Area Source Rule, subpart JJJJJ, which is not part of this rulemaking. Thus, the comment is out-of-scope with this rulemaking.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 9

Comment: Because of the significant changes being made to the existing BPH NESHAP, the applicability date used to distinguish new and existing sources must be changed to December 23, 2011, the date of the current proposal.

EPA has not proposed to change the date that identifies whether a source is new or existing from that in the current BPH NESHAP. That date, June 4, 2010, is the publication date of the original proposed rule. The current proposal significantly changes the requirements imposed and even the subcategories to which a boiler or process heater may be assigned. Since this is the first time these particular emission limits have been proposed, section 114(a)(4) of the CAA requires that the date that establishes what units are considered new sources and what units are considered existing sources must be changed to the date of the current proposal, December 23, 2011. Because the proposed changes to the major source BPH NESHAP are so extensive (as shown by the fact that EPA published this proposal as a total replacement for the existing final rule, rather than proposing only amendments), we recommend the change in applicability date needs to be made across the board. Even for the Gas 1 subcategory, where relatively little change is proposed, there are still significant changes in requirements and the many sources that meet the other gas 1 criterion will be now be in the gas 1 subcategory, rather than the gas 2 subcategory.

Response: We disagree with the commenter that the applicability date for the new unit definition should be reset from June 4, 2010 to December 23, 2011. The definition of a "New source" in section 63.2 clearly states that "New source means any affected source the construction or reconstruction of which is commenced after the Administrator first proposes a relevant emission standard under this part establishing an emission standard applicable to such source," EPA first proposed emissions standards for new major source boilers on June 4, 2010, and proposed to revise some of those standards in December 2011.

Commenter Name: Dirk J. Krouskop
Commenter Affiliation: MeadWestvaco Corporation (MWV)
Document Control Number: EPA-HQ-OAR-2002-0058-3493-A1
Comment Excerpt Number: 8

Comment: In the proposed rule, EPA has made the determination that it is appropriate to require compliance within three years of promulgation of this rule. As noted above, MWV does not believe this timeline is sufficient, but MWV does appreciate EPA's recognition that the timeline should be reset. MWV believes that it is appropriate to use this same logic to reset the date for new unit definition from June 4, 2010 to December 23, 2011.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 9.

Commenter Name: Matthew Todd
Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)
Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2
Comment Excerpt Number: 13

Comment: Additional time is needed for some new sources subject to numerical emission limits to comply with this rule.

Under this proposal, new sources subject to numerical emission limits have 60 days to come into compliance and 180 days to complete the performance testing and demonstrations needed to demonstrate such compliance.

Because the applicability date is being maintained at June 4, 2010, there will be "new sources" for which construction will have begun or may even have been completed. Yet, in some cases, these new sources will be unable to comply within 60 days, because they were designed on the basis of the June 2010 proposal or March 21, 2011 final rule. Paragraph 63.6(b)(3) of the part 63 General Provisions, which is applicable to this rulemaking per Table 10 of the proposal, deals with this situation and allows 3 years for compliance if the final standard is more stringent than the proposed standard, as long as the source complies with the proposal. This will be a critical allowance for some new source boilers and process heaters and we therefore recommend that the compliance time language in §§63.7495, 63.7510, and 63.7525 specifically reference §63.6(b)(3).

Response: The compliance date for new affected sources in the final rule is the effective date of the final rule which is the date of publication or upon startup whichever is later. We agree with the commenter that paragraph 63.6(b)(3) of the General Provisions is applicable and have revised 63.7495(a) to add "except as provided in §63.6(b)(3)." In the final rule, §63.7500(a)(1) has been revised to what emission limits new affected sources constructed between June 4, 2010 and May 20, 2011 may comply with as well as those new affected sources constructed between May 20, 2011 and the effective date of this final rule.

Commenter Name: Jessica Bridges
Commenter Affiliation: United States Clean Heat & Power Association (USCHPA)
Document Control Number: EPA-HQ-OAR-2002-0058-3501-A1
Comment Excerpt Number: 20

Comment: We are sensitive to the stated concern that the availability of equipment and installers will clash with the needs of electricity generating facilities affected by parallel rulemakings. Most users of CHP technology are much smaller than electricity generating facilities and may be placed further behind in the queue. Additional time is appropriate.

As indicated above in discussion of the Energy Assessments and the re-set Compliance timetable, we are supportive of the extension of the compliance schedule for existing facilities to at least three years from less than two years in the earlier version with provision for an extra year for installation of controls approvable on a case-by-case basis.

With respect to new sources, instead of the 60 day period after publication of the final reconsideration rule or 60 days after start-up whichever is later we recommend a 90 day period for similar reasons as stated above for the first five years then a switch to 60 days could be allowed.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 13.

Commenter Name: Gretchen Brewer
Commenter Affiliation: PT AirWatchers
Document Control Number: EPA-HQ-OAR-2002-0058-3825-A1
Comment Excerpt Number: 5

Comment: Testing and initial compliance requirements -- appreciate that owners of existing boilers must demonstrate compliance with the new laws. When will they take effect?

Response: See the response to comment EPA-HQ-OAR-2002-0058-3677-A2, excerpt 13.

Commenter Name: Matthew Todd
Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)
Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2
Comment Excerpt Number: 11

Comment: The proposal provides for three years compliance time from the publication of the final rule in the Federal Register. However, the rule is not effective until 60 days after that publication, since Congress has provided that time for its own review. As is done for new and reconstructed sources, compliance for existing sources should be based on the effective date, the date from which facilities can be fairly sure of the requirements that must be met, and the compliance date should therefore be three years and 60 days from the Federal Register publication date.

Response: Section 112(i)(3)(A) requires existing sources to comply with the emissions standards as expeditiously as practicable, but in no event more than 3 years from the effective date of the standards. The effective date of the final rule is the date of publication of the rule in the Federal register. The reconsideration is not a major rule under the Congressional Review Act, so under section 112(d)(10), the final rule is effective on publication.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 30

Comment: EPA can and must do more in the final Boiler MACT reconsideration rule. In particular, as it has done in at least one prior MACT standard, EPA should grant a categorical one- year extension. In promulgating MACT standards for marine tank vessel loading operations, the Agency determined that the rule "shall allow existing sources regulated solely under section 112 four years to be in full compliance with the emission control requirements promulgated under section 112." 60 Fed. Reg. 48388, 48392 (Sept. 19, 1995). EPA observed that "section 112(i) of the Act specifically allows EPA to provide sources with a waiver of up to 1 year to achieve full compliance" and that a categorical extension was warranted in that case because "standards containing similar compliance dates for a large number of sources would result in numerous facilities competing for a limited number of experienced contractors in order to meet the standards at the same time." *Id.* Thus, EPA clearly has construed § 112(i)(3)(B) as authorizing categorical compliance extensions.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3818-A2, excerpt 1.

Commenter Name: R. Thomas Buffenbarger

Commenter Affiliation: International Association of Machinists and Aerospace Workers

Document Control Number: EPA-HQ-OAR-2002-0058-3817-A2

Comment Excerpt Number: 1

Comment: The International Association of Machinists and Aerospace Workers requests you support our mission to extend the compliance timeframe for Boiler MACT regulations beyond the three years provided in existing rules. These regulations will certainly impact the lives and jobs of thousands of hardworking American citizens.

We urge you to implement a categorical one-year extension to comply with Boiler MACT Rules. The complexity and widespread nature of these rules will introduce a number of obstacles for American manufacturers competing in this global environment.

Given the urgency to meet the three-year deadline, thousands of manufacturing facilities will be vying for the same resources and skilled laborer, creating a scarcity of both. We are not equipped with the sufficient resources to meet these demands, and the shortage will lead to increased costs. Utility companies can pass these costs along to end users. Manufacturers in the forest products industry will be forced to absorb these costs. Unfortunately, we do not have the capital to absorb these costs and will be forced to immediately withdraw resources from this pending financial

disaster that will result in zero growth in manufacturing and immediate job loss within our communities.

We recognize the need to continue to improve the status of our environment, and we are committed to that end. Without responsible actions by our government we will not be able to compete with global competition. Once again, we urge you to implement a categorical one-year extension to comply with Boiler MACT Rules.

I thank you for your consideration of this request, and I look forward to your support.

Response: See response to comment EPA-HQ-OAR-2002-0058-3818-A2, excerpt 1.

Commenter Name: Holly R. Hart

Commenter Affiliation: United Steel Workers (USW)

Document Control Number: EPA-HQ-OAR-2002-0058-3498-A1

Comment Excerpt Number: 8

Comment: USW believes EPA has authority under the Clean Air Act to add an additional year to the standard three-year compliance period. USW urges EPA to give strong consideration to doing so.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3818-A2, excerpt 1.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 133

Comment: In light of the difficulty in meeting a three year compliance deadline as explained above, EPA and authorized states should be prepared to readily grant one-year extensions under CAA § 112(i)(3)(B) to those units that have problems installing the necessary control equipment to comply with the final rule. EPA should also make clear in this rule, as it did in the MATS rule³⁷, that the 1-year extension also applies to repowering projects as they are applicable to ICI boilers and process heaters:

"The EPA took comment on whether the construction of on-site replacement power could be considered the "installation of controls" such that a fourth year would be available while the replacement unit is being completed for a unit that is retiring (e.g., a case when a coal-fueled unit is being shut down and the capacity is being replaced on-site by another cleaner unit such as a combined cycle or simple cycle gas turbine). After reviewing the comments, EPA believes that it is reasonable for permit authorities to allow the fourth year extension to apply to the installation of replacement power at the site of the facility. The EPA believes that building replacement power constitutes the "installation of controls" at a facility to meet the regulatory requirements."

[Footnote 37: 77 Federal Register 9410, February 16, 2012]

Response: See the response to comment EPA-HQ-OAR-2002-0058-3818-A2, excerpt 1. We agree that the 1-year extension applies to repowering projects and will include similar language as in the MATS rule.

Commenter Name: Alicia Meads

Commenter Affiliation: National Association of Manufacturers (NAM)

Document Control Number: EPA-HQ-OAR-2002-0058-3515-A1

Comment Excerpt Number: 13

Comment: In many instances, the installation of pollution control equipment and associated charges to boiler must be permitted under state air pollution statutes and/or construction codes (building permits, etc.). The proposed rule will result in an increase in the number of permit applications, potentially swamping the state and local agencies. Even in those areas where the rule may not result in significant increases in permitting work, the normal delays associated with permitting may make meeting the three year compliance deadline impossible.

In light of the difficulty in meeting a three year compliance deadline, the EPA and authorized states should be prepared to readily grant one-year extensions under CAA § 112(i)(3)(B) to those units that have problems installing the necessary control equipment to comply with the industrial Boiler MACT rule.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3818-A2, excerpt 1.

Commenter Name: J. Michael Geers

Commenter Affiliation: Duke Energy

Document Control Number: EPA-HQ-OAR-2002-0058-3543-A1

Comment Excerpt Number: 1

Comment: Compliance Time - On May 18, 2011, EPA announced the reconsideration of the rule and issued a stay of the effective date of the March 21, 2011 final IB MACT rule. When EPA did so, Duke Energy understood that EPA was signaling that it was likely to significantly change the requirements of the rule upon reconsideration. The resulting uncertainty inhibited Duke Energy's ability to make appropriate selections of control technologies and make other compliance decisions. In the current rulemaking, EPA is proposing to not only change the requirements, but also to revise the compliance date for existing sources to three years after the date of publication of the final reconsideration rule in the Federal Register (FR). For new sources, the EPA has also proposed a compliance date 60 days after the date of publication of the final reconsideration rule in the FR, or upon startup, whichever is later. EPA's rationale is that these dates are appropriate so as to give affected facilities sufficient time to make compliance-related decisions and install controls. Duke Energy agrees with EPA and strongly supports this proposed approach, but urges EPA in the final rule to grant owners of all affected sources that are installing controls a one year extension of the three year compliance deadline.

In the preamble, EPA stated that Section 112 allowed for up to 3 years after promulgation for compliance along with an additional year for installation of controls that must be approved on a case-by-case basis by the permitting authority. EPA stated that it believed this provided enough time for boilers to achieve compliance. EPA also stated that maintaining the compliance dates

from the March 2011 final rule would essentially provide less than 2 years for sources to meet the final standards, whose stringency could not be determined until the reconsideration is final. For those reasons EPA proposed revising the compliance date for existing sources to three years after the date of publication of the final reconsideration rule. As a legal matter, Duke Energy asserts that EPA really has no alternative but to revise the compliance dates. However even with the compliance date reset to 3 years after the publication of the final reconsidered rule, Duke Energy continues to believe that this is inadequate time for some facilities to undertake the retrofits necessary to meet the new MACT standards.

In its comments on the initial proposed rule, Duke Energy asserted that it anticipated that industry will face severe constraints on permitting, construction time and material that will make it extremely difficult, if not impossible, for many facilities to meet the retrofit deadline of three years. Most of the targeted solid fuel-fired units are located at facilities that will have to undergo substantial re-engineering, e.g., due to space constraints, to accommodate new controls. Design, permitting, procurement, installation, and shakedown of many projects will easily consume three years. In short, more time is needed for some facilities. Moreover it is inevitable that many existing boilers will be forced to convert to an alternative fuel such as natural gas, or even construct entirely new boilers. EPA has not adequately considered these factors in either its initial final IB MACT rule or in its December 23, 2011 proposal.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3818-A2, excerpt 1.

Commenter Name: J. Michael Geers

Commenter Affiliation: Duke Energy

Document Control Number: EPA-HQ-OAR-2002-0058-3543-A1

Comment Excerpt Number: 2

Comment: Duke Energy urges EPA in the final rule to grant owners of all affected sources that are installing controls a one year extension of the three year compliance deadline. External factors will also jeopardize compliance within three years. A large number of companies will be competing nationwide for limited resources and materials from engineering consultants, equipment vendors, construction contractors, financial institutions, and other critical suppliers. It is likely many companies will find themselves unable to procure the necessary goods and services to complete the retrofitting of their affected units within three years. In particular, Duke Energy is concerned about sources being able to procure bag houses and scrubbers because immediate industry demand will outstrip immediately available supplies. Industry must continue to operate as best as possible while retrofitting to meet the new MACT standards. In general, the existing solid fuel-fired boilers that will be subject to this new rule comprise the most critical part of the base load energy supply for their facilities. These units typically have high capacity utilization rates. Extensive outages for retrofitting must be carefully planned. Only when all of the critical prerequisites for the retrofit have been lined up, e.g., the engineering is complete and the control equipment is staged for immediate installation, can an owner afford to shut down a facility's base load boiler to install the new controls. This will take careful planning and coordination both within the company and outside the company that will involve with engineering consultants, equipment vendors, and construction contractors. Duke Energy does not believe three years is sufficient to allow owners of many of the affected sources the time necessary to make the retrofits without substantial disruption to the operation of their facilities.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3818-A2, excerpt 1.

Commenter Name: Douglas A. McWilliams

Commenter Affiliation: American Municipal Power

Document Control Number: EPA-HQ-OAR-2002-0058-3685-A2

Comment Excerpt Number: 9

Comment: EPA Should Reset the Compliance Date to Provide Existing Sources with the Maximum Compliance Time Allowed by Law

EPA proposed resetting the Boiler MACT compliance date for existing sources to the date three years after publication of the reconsidered final rule. AMP supports resetting the compliance date, and encourages EPA to use the discretion granted under CAA § 112(i)(3) to grant a categorical 1-year extension to all sources installing control equipment to comply with the standards. The uncertainty generated by the complicated history of this regulation has made it impossible for sources to begin compliance planning prior to issuance of the final reconsidered rule. Even now, sources are uncertain of the final emissions limits, what controls may be necessary to achieve these limits, and whether they will be regulated by the Boiler MACT rule or the CISWI rule. The Boiler MACT rule will establish limits for multiple pollutants that require multiple controls and facilities cannot analyze the trade-offs posed by various control options until the final emission limits are published.¹⁶ Sources must also be cognizant of other regulations imposing emission limits for different pollutants when adopting a Boiler MACT control strategy. For example, a facility cannot implement a CO reduction strategy that will result in a NO_x increase if the facility is located in a non-attainment area or is otherwise subject to stringent NO_x emission limits. Some control options may affect pollutants subject to a National Ambient Air Quality Standard and changes in the concentration, temperature, velocity and height of the exhaust gas may adversely impact air dispersion modeling results triggering new concerns and complications. These complexities will require extensive and detailed planning that cannot take place until EPA finalizes the Boiler MACT emission standards.

[Footnote¹⁶: For example, presence of SO₃ can have a significant negative impact on the Hg removal that is achieved by activated carbon injection, and use of catalysts for NO_x and CO control can oxidize SO₂ in flue gas to SO₃. However, presence of SO₃ in flue gas tends to improve PM collection efficiency of ESPs by lowering ash resistivity and also may improve dioxin capture.]

Response: See the response to comment EPA-HQ-OAR-2002-0058-3818-A2, excerpt 1.

Commenter Name: Douglas A. McWilliams

Commenter Affiliation: American Municipal Power

Document Control Number: EPA-HQ-OAR-2002-0058-3685-A2

Comment Excerpt Number: 12

Comment: In particular, as it has done in at least one prior MACT standard, EPA should grant a categorical one-year extension to the proposed 3-year compliance date. In promulgating MACT standards for marine tank vessel loading operations, the Agency determined that the rule "shall allow existing sources regulated solely under section 112 four years to be in full compliance with

the emission control requirements promulgated under section 112." 18 EPA observed that "section 112(i) of the Act specifically allows EPA to provide sources with a waiver of up to 1 year to achieve full compliance" and that a categorical extension was warranted in that case because "standards containing similar compliance dates for a large number of sources would result in numerous facilities competing for a limited number of experienced contractors in order to meet the standards at the same time."19 Thus, EPA clearly has construed § 112(i)(3)(B) as authorizing categorical compliance extensions?20

[Footnote18: 60 Fed. Reg. 48388, 48392 (Sept. 19, 1995).]

[Footnote19: *Jd.*]

[Footnote20: The DC Circuit decision in the PCWP MACT case, *NRDC v. EPA*, 489 F.3d 1364 (D.C. Cir. 2007), does not take away EPA's authority to grant categorical 1-year compliance extensions. For further analysis of this opinion, see AF&PA Industry Comments.]

Response: See the response to comment EPA-HQ-OAR-2002-0058-3818-A2, excerpt 1.

Commenter Name: Richard D. Garber

Commenter Affiliation: Boise Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3686-A2

Comment Excerpt Number: 11

Comment: Critical path timeline risks are significant for these projects and may include, but are not limited to, delays caused by:

- Permit authority staff availability;
- Design engineering resource availability;
- Control equipment and fabricators supply equipment and/or manpower availability; and
- Delays in Title V and PSD permit review and approval at the state or regional EPA.

As can be seen from the schedule above, the full 36 months from promulgation of final regulations will be necessary for many facilities and will likely be insufficient for some facilities. With 36 months from final rule promulgation, scheduling will be tight and subject to risk. Failure to provide meaningful alternatives for facilities that will need additional time puts them at risk of not meeting the compliance deadline. For this reason, EPA needs to provide additional alternatives that can be used by sources to obtain more time to complete their projects. At a minimum, EPA should make clear that it will approve and authorize the use of the 12-month extension provisions in 40 CFR 63.6(i) to grant additional time for installation of control equipment and such other requirements that are necessary to achieve compliance with the standard.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3818-A2, excerpt 1.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and

Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 12

Comment: Sections 63.6(i)(4) through (16) of the part 63 General Provisions deal with the process for obtaining up to an additional year for compliance. This is a very cumbersome process, particularly since, as discussed above, many BPH and other combustion sources will be making these applications at the same time. To make this cumbersome process more feasible in the case-by-case scenario, EPA should specify in the BPH rule that multiple BPH can be addressed in a single application, that the request can be submitted as soon after the effective date of this rule as the source has adequate information to know it needs the extension, and that overall engineering and construction workload and BPH outage impacts may be a basis for the request in addition to equipment availability and delivery issues. In addition, the rule should be revised to include an automatic approval of an extension request if EPA fails to respond within 90 days of submission of the request.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3818-A2, excerpt 1. Section 112(i)(3)(A) states that EPA shall require existing sources to comply with emissions standards as expeditiously as practicable, but "...in no event later than 3 years after the effective date of such standards. The effective date of this final rule is the date of publication and the compliance date in the final rule is 3 years from the date of publication. Section 112(i)(3)(B) does allow the Administrator or State permitting authority to issue a permit that grants up to 1 year extension if necessary for the installation of controls. There is nothing in section 112(i)(3)(B) to indicate that a source can not address multiple affected units in a single application. The commenter's request for automatic approval of extension requests upon EPA failure to respond within 90 days is out-of-scope with this reconsideration rulemaking.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 31

Comment: The DC Circuit decision in the PCWP MACT case, *NRDC v. EPA*, 489 F.3d 1364 (D.C. Cir. 2007), does not take away EPA's authority to grant categorical 1-year compliance extensions. That case involved EPA's MACT standard for plywood and composite wood products (PCWP) manufacturing. EPA promulgated the rule in 2004 and amendments to the rule in 2006. The 2006 amendments did not change the emissions standards established in the 2004 rule. The 2006 rule only revised certain compliance assurance provisions. According to the court, "In the 2006 Rule, EPA extended by one year the compliance date for the emission standards established in the 2004 Rule in light of what it characterized as "substantial" changes made in the 2006 Rule." *Id.* at 1373. The court overturned the extension on the grounds that the 2006 amendments did not involve changes to the 2004 emissions standards and, therefore, the compliance deadline could not be extended because Congress "set an outer limit of three years after *emissions standards* took effect." *Id.* at 1374 (emphasis added).

The court expressly noted that EPA "did not rely" on § 112(i)(3)(B) (the 1-year compliance extension provision) in granting the extra year. *Id.* Thus, the meaning of § 112(i)(3)(B) was not

at issue in the case. But, the court did observe that "Congress enumerated specific exceptions to the three-year maximum, which indicates that Congress has spoken on the question and has not provided EPA with authority under subsection 112(i)(3)(B) to extend the compliance date in the 2006 rule." *Id.* Even if this dicta were assumed to have some legal force, that effect clearly would be limited to the given circumstances – *i.e.*, where EPA granted a compliance extension to accommodate new compliance assurance provisions and not because it made a finding that additional time was needed "for the installation of controls."

In the case of the Boiler MACT, EPA is proposing changes to several emissions standards, changes to the number and type of subcategories, and (in related proceedings) changes to the criteria that will be used in the first instance to determine whether a unit is covered by the Boiler MACT or the CISWI rule. All of these proposed changes will affect the level of the standards and the manner in which these standards will be applied to affected sources. This means that EPA's proposal to reset the compliance deadline for existing sources is justified by the facts and wholly consistent with the holding in *NRDC v. EPA*.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3818-A2, excerpt 1.

Commenter Name: J. Michael Geers

Commenter Affiliation: Duke Energy

Document Control Number: EPA-HQ-OAR-2002-0058-3543-A1

Comment Excerpt Number: 3

Comment: Duke Energy recommends EPA address the foregoing problems by clearly extending the compliance deadline to four years after the publication of the final regulations in the Federal Register for units that need the additional time to install controls. EPA must clearly articulate the conditions under which a source is eligible for this extension at the time that the rule is finalized. If it is uncertain whether a source can qualify for an extension or it must go through an uncertain regulatory approval process, there is no way that source can effectively count on that extension into its planning process and risk possible non-compliance. Duke Energy made similar arguments in the Utility MACT rulemaking only to see EPA fail to provide the needed certainty. Subsequently the company has met with at least one state agency that advised the company that it could not provide a final answer for at least a year on whether a facility contemplating an extensive emissions controls retrofit would qualify for a fourth extension year. This has put the company in the unacceptable position that if it begins a control retrofit project that will require more than three years to implement, it will not know until a year into the project whether an extension will be granted. Duke Energy believes the Agency is fully justified in invoking § 112(i)(3)(B) of the Clean Air Act to grant owners of all affected sources that are installing controls a one year extension of the compliance deadline. Four years would provide critically needed time for industry to conduct the necessary control retrofits. Given the magnitude of the retrofit requirements and the likelihood of substantial difficulties fulfilling these requirements, it is essential that EPA provide a clear, specific answer at the time the rule is finalized on what qualifies for a fourth year, rather than just articulate an uncertain process.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3818-A2, excerpt 1.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 32

Comment: Additional air pollution controls will need to be installed on thousands of industrial boilers and utility boilers over the next few years. Engineering firms and air pollution control suppliers simply do not have the capacity to satisfy all of the demand within the next three years. Thus, as in the marine vessel tank loading standard, EPA can and should issue a categorical one-year extension of the compliance deadline for existing industrial boilers.

If a categorical exemption is not issued, then EPA should provide guidance to permitting authorities on situations where a 1-year extension should be granted upon request. EPA should make clear in this rule, as it did in the MATS rule, that the 1-year extension not only applies to installation of pollution control measures but also applies to repowering projects:

"The EPA took comment on whether the construction of on-site replacement power could be considered the "installation of controls" such that a fourth year would be available while the replacement unit is being completed for a unit that is retiring (e.g., a case when a coal-fueled unit is being shut down and the capacity is being replaced on-site by another cleaner unit such as a combined cycle or simple cycle gas turbine). After reviewing the comments, EPA believes that it is reasonable for permit authorities to allow the fourth year extension to apply to the installation of replacement power at the site of the facility. The EPA believes that building replacement power constitutes the "installation of controls" at a facility to meet the regulatory requirements." (see 77 Fed. Reg. 9410)

Response: See the response to comment EPA-HQ-OAR-2002-0058-3818-A2, excerpt 1.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 34

Comment: Industry is committed to complying with all applicable air regulations. However, many industry sectors have evaluated and concluded that a 3-year compliance window will not allow facilities to meet the emission standards for the boiler rules in the required timeframe. The demand for resources will be such that even the most proactive site will not be guaranteed it can develop an emissions reduction strategy, secure funding, engage qualified consulting firms and vendors, install equipment, and complete testing and tuning in a 3-year period in a manner that can ensure compliance. While a one year extension could provide additional time for some sources, one year is not enough in this case due to the high number of sources that will need to make modifications at their existing facilities. Accordingly, the compliance deadline for the upcoming boiler rules should be extended to five years to ensure affected facilities will be able to achieve the required emissions reductions prior to the compliance dates of the rules.

If faced with an impossible compliance deadline, many affected sources in the industries affected by these rules would have no choice but to curtail the operation of affected combustion units,

which could compromise the productivity of affected facilities or even cause them to shut down. The resulting impact on the Nation's basic manufacturing capacity and the corresponding impacts on the economy as a whole – particularly in this time of protracted economic malaise – would be severe.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3818-A2, excerpt 1.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 33

Comment: Because at least 5 years of compliance time will be needed under the Boiler MACT, EPA and the President should take the additional step of extending the compliance deadline by at least one additional year using a Presidential exemption. Under CAA § 112(i)(4), the President is authorized to exempt affected sources for a period of up to two years (which may be renewed an indefinite number of times) upon a finding that: (1) it is in the national security interest to do so; and (2) the technology to implement the standard is not available. There should be little doubt that protecting the viability of affected industries is in the national security interest. Moreover, for all of the reasons described above, a solid case can be made that the needed air pollution controls will not be available. Therefore, a Presidential exemption is justified and should be issued. We note that the time and effort required to issue such an exemption should not be materially greater than the time and effort needed to produce the Presidential memorandum that was issued at the time the MATS rule was signed. So, EPA and the administration have demonstrated that issuing such an exemption is practicable and can be done in a timely manner.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3818-A2, excerpt 1. Further, the existing source compliance date in MATS is three years from the effective date of that rule. Moreover, any Presidential exemption pursuant to section 112(i)(4) must be issued by the President – not by EPA -- based on his determination that the technology to implement a standard is not available and that it is in the national security interests of the United States to grant an exemption from compliance. Further, while the commenter asserts that “protecting the viability” of industries subject to the boiler MACT is in the interest of national security, it provides no explanation to support this assertion.

Commenter Name: Richard D. Garber

Commenter Affiliation: Boise Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3686-A2

Comment Excerpt Number: 12

Comment: More appropriate in our view, EPA should adopt a significantly longer compliance deadline. Nominally, EPA should adopt by rule an across-the-board one-year extension pursuant to § 112(i)(3)(B). However, even a four-year compliance period will be inadequate for many affected sources. Therefore, EPA should provide additional time by: (1) granting in the final rule a Presidential extension under § 112(i)(4), given that it is in the "national security interests of the United States" to prevent widespread noncompliance in the industrial base; (2) declaring that the statutory three-year compliance period is impossible to meet or otherwise produces "absurd

results," which as demonstrated in EPA's recent PSD Tailoring Rule are doctrines that allow EPA to depart from clear statutory directives in appropriate circumstances; and/or (3) establishing phased or sequenced requirements such that certain element of the rule become effective no later than three years after promulgation (thus satisfying § 112(i)(3)(A)), while others are phased in at later times.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3818-A2, excerpt 1 regarding extending the compliance date past 3 years from publication of final rule for existing sources. See the response to comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 33 regarding issuing a Presidential extension.

Commenter Name: Alicia Meads

Commenter Affiliation: National Association of Manufacturers (NAM)

Document Control Number: EPA-HQ-OAR-2002-0058-3515-A1

Comment Excerpt Number: 14

Comment: In addition, the EPA should establish an extended two-step compliance period for situations where a boiler owner voluntarily elects to replace or retrofit a boiler to burn a cleaner fuel source.⁶ If a facility decides to switch to a cleaner fuel, the replacement or retrofit work required to make that switch will potentially take years, for all of the reasons discussed above. Rather than require the facility to add emissions controls to its existing boiler in time for the proposed three year compliance deadline – likely eliminating the possibility that the facility would switch to a cleaner fuel source – the EPA should allow five years total for facilities to change their boilers and meet the MACT requirements for the cleaner fuel source. This five year period would occur in two steps; a no-backsliding provision would apply for two years from publication of the rule in the Federal Register, and then the facility would have three years to comply with MACT standard for the subcategory for the cleaner fuel subcategory. The EPA promulgated exactly this type of extended MACT compliance deadline for certain facilities that voluntarily elected to install new technology as part of the Pulp and Paper Cluster Rule. *See* Pulp and Paper Cluster Rule, 60 Fed. Reg. 18503, 18,508 (Apr. 15, 1998).⁷ In addition to providing an incentive for facilities to switch to cleaner fuel sources, this approach would reduce some of the competition for resources discussed above by extending the deadline to complete the work to replace or retrofit certain boilers.

[Footnote 6: EPA recognizes the MACT rule should be crafted to encourage the use of cleaner fuels, such as natural gas. 75 Fed. Reg. 32025.]

[Footnote 7: This two-step approach for the MACT standard is consistent with the D.C. Circuit's decision in *NRDCv. EPA*, 89 F.3d 1364 (D.C. Cir. 2007) (finding invalid EPA's decision to extend the compliance deadline for a promulgated MACT rule by a year because of the substantial changes that the agency made to the rule). Rather than functioning as an extension of the compliance deadline, this MACT standard for certain facilities would become applicable in two steps. For the first three years, a no-backsliding MACT standard would be applicable, then the three year deadline to implement the MACT standard for the applicable "cleaner" source would begin to run.]

Response: See the response to comment EPA-HQ-OAR-2002-0058-3818-A2, excerpt 1 regarding extending the compliance date past 3 years from publication of final rule for existing sources. See the response to comment EPA-HQ-OAR-2002-0058-3521-A1, excerpt 33 regarding issuing a Presidential extension.

Commenter Name: Frank H. Thorn

Commenter Affiliation: Newport News Shipbuilding

Document Control Number: EPA-HQ-OAR-2002-0058-3548-A2

Comment Excerpt Number: 18

Comment: Replacement of the NNS Floating Test Steam Facility (FTSF) marine boilers is not cost-effective and cannot be accomplished by the Boiler MACT compliance date. NNS has also evaluated the possibility of scrapping its existing oil-fired FTSF marine boilers and replacing them with an entirely new, natural gas or propane-fired system, since no numeric emission limits would apply to gas-fired units pursuant to the Boiler MACT. Replacement with a distillate oil-fired system is not a viable option, because the emission limitations for the “Units designed to burn liquid fuel” subcategory, identified earlier, would still apply, and new, distillate oil-fired boilers would not be able to meet all of the applicable emission limitations without add-on controls. NNS has already determined that it is not feasible to install the add-on emission control equipment on a floating, portable steam generating facility that would be required by firing oil. The time and cost to construct a new test steam facility can be accurately estimated due to actual, relevant NNS experience. The Navy’s aircraft carrier delivery and overhaul schedules are established many years in advance and, for example, revealed several years ago that concurrent steaming of two aircraft carriers would be required in 2008. NNS is required by the Navy to adhere to the Navy’s carrier overhaul schedule and plan accordingly. As a result in 2002, six years before the schedule steaming date, NNS completed a study to determine the recommended approach for providing the needed additional test steam capacity in 2008. The Navy subsequently authorized and funded a plan to construct a second, temporary, land-based “test steam” facility that would be dedicated to the steaming of one specific aircraft carrier at one aircraft location at NNS beginning in 2008, while the existing NNS-owned FTSF would concurrently provide test steam to another aircraft carrier at a second shipyard location, as originally scheduled. A new, distillate-oil fired, temporary, land-based test steam facility was designed and constructed over a five-year period, was utilized for steaming the assigned aircraft carrier as scheduled beginning in 2008, and was then dismantled in 2010 in accordance with Navy contract directions. The temporary test steam facility consisted of two distillate oil-fired watertube boilers, each rated at 245.3 million BTU per hour, which compares very closely with the size of NNS’ existing FTSF boilers, which are rated at 213.26 million BTU per hour. Due to the unique and highly specialized nature of propulsion system test steam boilers, the construction cost of this temporary test steam facility was over \$25 million, and would have been higher if the facility had been constructed as a permanent system inside a permanent building, as would a conventional industrial boiler system. This high actual cost of a replacement test steam facility is further evidence that aircraft carrier test steam boilers systems are fundamentally different than industrial boiler systems and should not be regulated as industrial boilers under the Boiler MACT. Based on the actual cost of this temporary test steam facility, NNS believes that, while technically feasible to replace the existing FTSF marine boiler system with a new, gas-fired, portable system mounted on a barge to meet the aforementioned portability requirements for

aircraft carrier steaming, the current-day cost is expected to be in the range of at least \$30-\$35 million, which again significantly exceeds EPA's Boiler MACT compliance cost estimates for industrial boilers of this size. Furthermore, because the required natural gas supply is currently not available at NNS, this cost does not include the cost of constructing a new, high pressure natural gas pipeline from a distant location in the City of Newport News, Virginia, to the NNS shipyard and then to several potential points of use along the waterfront. The estimated additional cost for extending the natural gas distribution system from the NNS property line to at least two distinct waterfront locations within the shipyard is estimated at between \$1.5 million and \$2.5 million. The overall time required to design the temporary, land-based test steam facility, construct the facility, make it operational and achieve acceptance from the Navy was 45 months. NNS believes that approximately the same amount of time would be required to construct a similar replacement system for the FTSF. Preceding the construction phase, at least nine months would be required to obtain funding from the Navy, bringing the total time required to about 54 months. This time does not include the time required prior to commencement of construction to prepare applications for and obtain permits under the New Source Review, Greenhouse Gas PSD and Part 70 Permit programs (currently estimated to require 12 months or longer). NNS notes that under Clean Air Act provisions and federal and state environmental rules NNS may not enter into any binding agreements or contractual obligations, which cannot be canceled or modified without substantial loss to NNS, prior to obtaining all required air permits and meeting all preconstruction requirements. Therefore, NNS does not believe that replacement of its FTSF marine boilers with new, gas-fired units can be accomplished by the Boiler MACT compliance date, currently March 21, 2014 (even if eventually delayed as a result of the pending proposed amendments to the Boiler MACT).

Response: We agree with the commenter that FTSF aircraft carrier test steam boiler systems are unique. In the final rule, the exemption for boilers or process heaters that are used specifically for research and development has been revised to include these types of boilers because these test boilers perform the same function as boilers exempted at research and development facilities. These test boilers do not provide heat or steam to a process. The boilers are used only to test the propulsion systems on nuclear powered aircraft carriers.

Commenter Name: Frank H. Thorn

Commenter Affiliation: Newport News Shipbuilding

Document Control Number: EPA-HQ-OAR-2002-0058-3548-A2

Comment Excerpt Number: 20

Comment: The Presidential Exemption provided by section 112(i)(4) of the Clean Air Act, if obtained, would not provide a permanent exemption from the Boiler MACT, but rather would serve only to temporarily delay applicability of the Boiler MACT. The Presidential Exemption provided by section 112(i)(4) of the Clean Air Act does not provide sufficient relief to allow NNS to continue operation of the FTSF and provide carrier steamings on the schedule required by future RCOH events. This provision of the Clean Air Act provides for an exemption from compliance with a MACT regulation for an initial period of not more than two years. Thereafter by statute such an exemption may be extended for one or more additional periods, each period not to exceed two years. Even if an initial Presidential Exemption were sought by NNS at this time and obtained, NNS has no assurance that such an exemption would be extended one or more times by future administrations, and the failure to obtain any one extension in the future on

which NNS had relied would then immediately jeopardize NNS' ability to meet its obligations to the Navy and would significantly impact the readiness of the Navy's fleet. The Presidential Exemption process thus provides only a temporary delay mechanism and does not satisfactorily resolve the infeasibility of meeting the Boiler MACT requirements.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3548-A2, excerpt 18.

14Z. Out of Scope: Compliance

Commenter Name: Claudia M. O'Brien, Latham & Watkins LLP

Commenter Affiliation: JELD-WEN, inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3485-A1

Comment Excerpt Number: 16

Comment: EPA should permit alternative, less burdensome means to demonstrate compliance for sources which use a control device to demonstrate compliance with the emission limits, sources for which the initial compliance test demonstrates compliance with the emission limits, or sources which burn clean fuels. For instance, EPA could allow a source, group of sources, or industry sector to make a demonstration that certain fuels are "clean," or inherently low-HAP, with emission rates less than the relevant emission limits. Using this approach EPA could allow facilities to do a composite sampling of an appropriate time frame based upon the complexity of the fuel mix/fuel feed to predict the upper-limit of potential contaminant levels for acid gases and metals based upon the potential combination of fuels and the representative operating conditions. Continuous compliance with the acid gas and metals emission standards would be demonstrated by fuel feed monitoring rather than requiring annual source testing (or monthly fuel analysis) for these sources that burn clean fuels with inherently low-HAP emissions. Under this approach EPA could require sources to certify the type of fuel they are burning to ensure that the same clean fuels tested in the composite sampling remain in use, guaranteeing that the emission standards are met. The facilities would be required to perform the composite sampling again if the fuel source changes. For any pollutants not covered by the fuel testing, the facilities would be required to conduct initial compliance testing with subsequent testing performed every two years as EPA has required in other MACT regulations.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Eric Guelker, Alliant Energy Corporate Services, Inc.

Commenter Affiliation: Interstate Power and Light Company (IPL) and Wisconsin Power and Light Company (WPL), Alliant Energy Corp.

Document Control Number: EPA-HQ-OAR-2002-0058-3492-A1

Comment Excerpt Number: 5

Comment: If a CO emissions limitation is left in the final reconsidered rule, then averaging should be allowed for this pollutant as well. In particular, there may be instances where multiple units regulated by this rule vent to a combined stack and this may be the only acceptable location for measuring compliance. In this case, the only accurate measurable location would be the averaged emission rate.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Eric Guelker, Alliant Energy Corporate Services, Inc.

Commenter Affiliation: Interstate Power and Light Company (IPL) and Wisconsin Power and Light Company (WPL), Alliant Energy Corp.

Document Control Number: EPA-HQ-OAR-2002-0058-3492-A1

Comment Excerpt Number: 8

Comment: Where certain smaller light oil-fired house heating boilers (less than 100 mmBtu/hr) are not currently required to conduct stack testing for compliance under Title V permits, then the EPA should allow an option of using a sulfur content limitation as compliance assurance and demonstration of the PM limit for those light oil-fired small house heating boilers.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Shannon S. Broome

Commenter Affiliation: Auto Industry Forum (AIF)

Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1

Comment Excerpt Number: 2

Comment: As discussed in more detail elsewhere in these comments, for units that already have CO CEMS for reasons unrelated to the Industrial Boiler MACT, compliance with the Industrial Boiler MACT stack-test-based CO emissions limitations would be difficult to maintain. Stack tests are required to be run under representative operating conditions, typically defined as operating at or near full load consistently for the duration of the stack test. In sharp contrast, CEMS take emissions data on a near-continuous basis, which means CEMS emissions measurements reflect significant variability in emissions (for example, due to load swings and low load conditions) that was not measured during the stack tests used to set the CO standard. This problem is not overcome by statistical manipulation of the CO standard, such as accounting for variability using the UPL method, because such statistical methods unrealistically extrapolate only from the variability measured during stack tests and the variability between stack tests. In other words, this is a classic "apples and oranges" situation where emissions data from CO CEMS are incompatible with emissions data from stack tests used to set the CO standard.

One way for EPA to resolve this incompatibility is to determine that emissions data from CO CEMS are not credible evidence for purposes of assessing compliance with the Industrial Boiler MACT stack-test-based CO emissions limitations. As the Agency explained in the "credible evidence rule," data and information derived from methods other than the specified reference test method (so-called "non-reference test data") are relevant to showing compliance only to the degree that "the appropriate reference test would have shown a violation." 62 Fed. Reg. 8314, 8323 (Feb. 24, 1997). Because the Industrial Boiler MACT CO standards are based on stack test data, and because the stack tests on which the standards are based were required to be conducted during representative operating conditions (*i.e.*, consistently operating at or near full load), then by definition CO CEMS data taken during periods of operation that do not reflect "representative operating conditions" are not data that are relevant to showing compliance with the standards.

In other words, the stack test data on which the standards are based reflect operation during a narrow, limited, and optimum set of conditions. Thus, CO CEMS data that are taken during periods of operation that do not reflect those conditions are not relevant to determining whether an affected source is in compliance with the standard.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Alicia Meads

Commenter Affiliation: National Association of Manufacturers (NAM)

Document Control Number: EPA-HQ-OAR-2002-0058-3515-A1

Comment Excerpt Number: 19

Comment: The NAM supports the EPA's proposal to allow a co-fired unit to opt out of the CISWI rule and into the Boiler MACT rule, or vice versa. This will provide a beneficial measure of flexibility to operators. However, the EPA should eliminate the arbitrary restriction in the proposal that would limit a facility from moving from being regulated under CISWI to being regulated under Boiler MACT for a six month period after it had stopped burning solid waste. As a policy matter, forcing operators to remain regulated under the one standard when there are reasons to switch would needlessly penalize them with little to no benefit gained.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 20

Comment: The industrial boiler, solid waste incinerator, and utility boiler rules will require major equipment installations across a large number of existing facilities. The industrial Boiler MACT will require reductions of air emissions from almost 1600 major source boilers for at least one of the following four pollutants: particulate matter (PM), hydrogen chloride (HCl), mercury (Hg), and carbon monoxide (CO). The solid waste incinerator rule is expected to require emissions reductions from about 90 units classified as solid waste incinerators for one or more of the following nine pollutants: PM, lead, cadmium, HCl, CO, dioxin/furan, mercury, sulfur dioxide (SO₂), and nitrogen oxides (NO_x).³² The electric utility MACT (MATS rule) will require reductions of air emissions from the majority of the affected 1350 coal- and oil-fired utility boilers for at least one of the following pollutants: HCl, PM, and Hg for coal and pet coke, and HCl, hydrogen fluoride (HF) and Total HAP Metals for oil. These emissions reductions will be accomplished with installation of air pollution control equipment, fuel system changes, combustion air changes, or some combination of these measures, assuming facilities elect to continue operating these units and using current fuels. Because the limits for each pollutant in each rule were set individually, they do not represent the real world performance of any one boiler or incinerator, and it is likely that almost all units will have to make retrofits or install new controls for at least one if not multiple pollutants. Therefore, there are about 3000 units that

could require at least one new control device or retrofit to existing emissions control devices or fuel feed systems, or both.

[Footnote 32: Hundreds of additional units may be regulated as incinerators depending on the final definition of Non-Hazardous Secondary Materials.]

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 21

Comment: The compliance schedule is approximately the same for all of the boiler and incinerator rules. In addition, there are several other promulgated or pending rules that will add to the competition for quality consultants and vendors including implementation of NOX and SO2 NAAQS, Cross-State Air Pollution rule, other MACTs, and various Risk and Technology Review sector rules. Therefore, companies will be competing for consulting, stack testing, engineering, and fabrication resources at the same time. Increased demand will result in greater costs for these services. Never before has EPA simultaneously promulgated multiple rules that require such a large number of controls over such a short time period. Affected facilities cannot make decisions on what controls to implement prior to promulgation of the final rules.

Not only are the final numerical standards in each rule unknown, but in the case of facilities affected by the NHSM rule, such facilities cannot yet determine whether they are burning "fuel" (and thus subject to Boiler MACT) or "solid waste" (and thus subject to the Commercial and Industrial Solid Waste Incinerator (CISWI) rule). This problem is exacerbated in EPA's re-proposal due to the complexity of required analyses and the need to go through petition processes to receive final EPA determinations about whether a material is a waste or a fuel. These factors will aid in determining what emissions reductions options will work best, and the best control strategy for a particular unit will depend on many factors: configuration of the unit, amount of reduction required of each pollutant, fuel(s) fired, availability of alternate fuels, available space, unit operating characteristics, and other constraints.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 25

Comment: Following project approval, a facility must engage a firm to perform detailed engineering. Air permits also have to be obtained in order to authorize the modifications that will be made. State permitting agencies are already overloaded, and the boiler rules will only cause an increase in their workload and permit issuance times. When the detailed engineering is

complete, a bid package must be prepared in order to solicit proposals from firms that will be engaged to actually fabricate the equipment required. The fabrication and delivery of equipment is typically the step in a capital project that takes the longest, with some specialized equipment (e.g., rotating equipment) requiring very long lead times. With potentially 3000 capital projects that will need equipment, it is anticipated that delivery times will increase dramatically, with larger (and potentially more profitable) utility projects likely taking precedence with equipment suppliers. Equipment and installation costs also will rise due to increased demand, thus further straining resources.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 26

Comment: Once equipment is fabricated and delivered, there is another set of steps for installation and testing. Facilities will have to schedule shutdowns for equipment to be installed, or preferably wait until normally scheduled shutdowns occur. For companies with multiple facilities, shutdowns will need to be staggered over the course of a year or more so production doesn't drop off (creating additional pressures for economic sectors that are supported by the facilities we represent) and customer demands can be met. The timing of the actual retrofit work must be carefully planned far in advance, particularly for boilers that provide the primary energy supply for a facility. In many cases, this timing must coincide with periods of reduced steam demand, thus severely limiting the ability to install equipment and in some cases requiring phasing over two or more years. Once equipment is installed, it must be tested and tuned to ensure emission limits will be met over all operating conditions. For units burning multiple fuels, the testing will be more involved to make sure emission limits are met for multiple fuel firing configurations. Different boiler operating scenarios might require different control equipment operating scenarios (e.g., different sorbent injection rates). In addition, since industrial boiler owners have not previously had to control CO emissions, additional testing and tuning will be required to ensure the efficacy of these control strategies. Scheduling and conducting these complex emission tests over extended time periods will also be very difficult. Many of the emission limits are lower than these types of combustion units and emissions controls have ever been required to achieve, with actual emission rates near test method detection limits. Therefore, the configuration of the control equipment will take time, and facilities will need to evaluate the equipment well before the compliance date in case adjustments need to be made.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 76

Comment: We agree that incorporating emissions averaging into the Boiler MACT is a proper way to encourage flexibility and cost savings for affected facilities. There is ample precedent in the MACT program for allowing emissions averaging. Emissions averaging is a well demonstrated technique for meeting or exceeding environmental objectives at lower cost and with greater flexibility tailored to individual affected facilities. Provisions such as these allow plants to optimize their investments by installing controls on units where the lowest emission rates can be achieved in the most cost-effective manner possible. For example, a source could decide to over-control a newer unit (with either add-on controls or use of a lower-polluting fuel) in order to avoid costly investments in an older unit that may be retired before the useful life of the control device is reached. More flexible emissions averaging provisions would encourage additional use of lower- polluting fuels. Emissions averaging provisions also provide environmental benefit by allowing for control options that minimize energy use. Energy efficient decisions benefit the environment by reducing power demands and the secondary pollutant impacts they generate.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 81

Comment: It is possible that a CO CEMS-equipped boiler may be required to conduct CO stack tests for reasons unrelated to the Boiler MACT (e.g., the unit may have a PSD permit or state construction permit that requires such testing). To prevent confusion, EPA should clearly specify in the final rule that, if an affected source chooses to comply with the CO CEMS-based standard, it is not subject to the stack test-based CO standard – even if it conducts CO stack tests for other purposes. Conversely, EPA should also clarify that even if a unit has CO CEMS installed, it may choose to comply with the stack test-based CO limit, and in this case, CO CEMS data are not to be used for compliance.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 121

Comment: EPA has proposed a mechanism for units to move between the boiler and CISWI rules, but sources must wait 6 months after cessation of solid waste burning to move back under Boiler MACT and must provide 30 days notice of intent to re-commence combustion of solid waste.⁵⁴ EPA arbitrarily chose 6 months. With the extensive monitoring and testing required under both rules and the fact that any facility's Title V permit will include extensive compliance assurance provisions, facilities will be able to adequately ensure compliance under either rule without being restricted on the frequency of fuel switching. Sources should be allowed to make

the switch between waste and fuel as often as operational concerns require as long as they keep adequate records. EPA has also not adequately addressed startup and shutdown emissions under the CISWI rules. As startup and shutdown have been addressed using a work practices approach that requires operators to follow established procedures and use good combustion practices, coverage of ERUs as boilers during these periods (as long as they are not firing waste) is appropriate.

The 6-month waiting period will also pose a problem for a boiler operator that inadvertently fires a small amount of solid waste. The facility will not be able to comply with the CISWI requirements for the 6-month period specified. The boiler would have to be shut down for a 6 month period, which is a disproportionate penalty. The probability of such a scenario is increased by the unclear criteria in the NHSM rule and the fact that operators may be challenged by third parties on their non-waste fuel determinations.

[Footnote 53: See for example AF&PA comments on June 4, 2010 proposal at EPA-HQ-OAR-2002-0058-3213, pp. 214-244.]

[Footnote 54 See 40 CFR 60.2145(a)(2) and 40 CFR 63.7545(g).]

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 37

Comment: As another alternative compliance method for the stack test CO limits, EPA could establish a performance standard that would apply during the periods between stack tests. Such a standard could consist of a numeric value indicative of good combustion – such as oxygen or CO levels in the furnace or stack. Under this approach, EPA would also specify appropriate monitoring methods, such as oxygen meters or CO CEMS. But, if parametric monitoring indicated an exceedance of the performance standard, such an exceedance would not constitute a violation if appropriate corrective action were taken within a reasonable time after the exceedance was measured.

In concept, such an approach would be analogous to bag leak detection systems on baghouses, which EPA routinely requires in its standards. When a leaking bag is detected, EPA's rules typically do not define such an event as a violation. Instead, the affected source is required to replace the leaking bag and only might be found in violation if this corrective action is not taken within a specified period. So, there is clear precedent for applying this concept to the IB MACT stack test CO standards.

EPA would have ample justification to adopt this approach as a work practice under § 112(h). Among other things, EPA is authorized to adopt work practices under § 112(h) when "the application of measurement methodology to a class of sources is not practicable due to technological and economic limitations." That is clearly the case with the IB MACT stack-test-based CO emissions limitations. While it is true that certain relevant constituents such as oxygen

and CO can be measured, the "application" of such methods is not technologically practicable because the data that are collected cannot reasonably be used to show compliance with a stack test CO limit. As explained above, the data largely would be taken during periods when the affected source was not operating under the same conditions as existed during the stack tests used to set the standards (again, creating an irreconcilable "apples to oranges" problem). Available methods such as oxygen or CO monitoring are not economically practicable because the "apples to oranges" problem cannot be solved merely by spending more money refining the methods.

Thus, EPA has authority and justification to set performance standards for the periods between periodic stack tests.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Allison Watkins, Baker Botts

Commenter Affiliation: Class of '85 Regulatory Response Group

Document Control Number: EPA-HQ-OAR-2002-0058-3608-A1

Comment Excerpt Number: 8

Comment: EPA should allow sources flexibility to determine the most appropriate continuous compliance method (*i.e.*, CEMS, CPMS, stack testing, fuel analyses or sulfur content limitations) for the HAP limits. EPA should allow facilities to conduct stack tests as an additional compliance option, as it has done in prior rulemakings.¹³ Units that are not required to conduct stack testing for compliance with Title V permits, such as light oil-fired house heating boilers under 100 mmBtu/hr, should be allowed the option of using a sulfur content limitation as compliance assurance and demonstration of the particulate matter ("PM") limit. The Group believes these methods will be equally effective as CEMS or CPMS at ensuring compliance with an applicable standard.

[Footnote 13: EPA allowed this option in the MATS rule. While the MATS require quarterly stack testing, this frequency is not warranted for the smaller units regulated under this rule. *See* 77 Fed. Reg. at 9371.]

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Mark Weiss

Commenter Affiliation: Reciprocal Energy Company

Document Control Number: EPA-HQ-OAR-2002-0058-3658-A2

Comment Excerpt Number: 8

Comment: Biomass is an inconsistent fuel and variations will exist in firing results. Our technology continually monitors CO and O2 as control parameters. EPA should understand and allow plant operators to properly manage CO levels. An optimal 3-hour test does not describe the real world.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Randal G. Oswald

Commenter Affiliation: Integrys Energy Group

Document Control Number: EPA-HQ-OAR-2002-0058-3659-A2

Comment Excerpt Number: 8

Comment: EPA should allow sources flexibility to determine the most appropriate continuous compliance method (*i.e.*, CEMS, CPMS,⁹ stack testing, fuel analyses or sulfur content limitations) for the HAP limits. EPA should allow facilities to conduct stack tests as an additional compliance option, as it has done in prior rulemakings.¹⁰ Units that are not required to conduct stack testing for compliance with Title V permits, such as light oil-fired house heating boilers under 100 mmBtu/hr, should be allowed the option of using a sulfur content limitation as compliance assurance and demonstration of the PM limit. Integrys believes these methods will be equally effective as CEMS or CPMS at ensuring compliance with an applicable standard.

[Footnotes]

(9) Integrys appreciates EPA's consideration of particulate matter Continuous Parametric Monitoring Systems ("PM CPMS") as an alternative to the PM continuous emission monitoring system ("CEMS") requirement. However, PM CPMS are not a viable alternative for many units.

(10) EPA allowed this option in the MATS rule. While the MATS require quarterly stack testing, this frequency is not warranted for the smaller units regulated under this rule. See 77 Fed. Reg. 9304, 9371 (Feb. 16, 2012).

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Robin Mills Ridgway

Commenter Affiliation: Purdue University

Document Control Number: EPA-HQ-OAR-2002-0058-3668-A2

Comment Excerpt Number: 10

Comment: As an alternate to replacing the CO numerical standard with a work practice standard, Purdue suggests that in addition to the two CO compliance options in the reproposal (CO CEMS or a CO stack test), EPA could endorse a petition process for unit-specific CO limits for units that cannot implement cost-effective modifications to comply.

EPA could allow for a petition to the permitting authority for determination of a unit-specific CO emission limit if it is determined that a boiler or process heater cannot attain the final rule CO emission limit without major unit redesign, oxidation catalyst addition with associated stack gas reheat and increased fuel usage, exceedance of an applicable NOx standard, or derating the unit. As EPA has monetized benefits for only PM2.5 and its precursors (NOx and SO2) it is apparent that requiring drastic reductions in CO emissions to the detriment of NOx emissions and unit efficiency is not the desired outcome.

The process of determining a unit-specific CO limit could include:

- performing a tune-up according to a standard industry protocol (e.g., ASME PTC 4-2008, Fired Steam Generators, which provides rules and instructions for conducting performance tests of fuel fired steam generators)
- inspection and maintenance of the boiler/process heater and its fuel supply system to ensure they are in good operating condition,
- testing for CO emissions over the range of operating conditions to determine a site-specific CO limit and appropriate operating parameter limits, and
- establishment of a protocol for ongoing unit operation to ensure good combustion practices.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Steve Gossett

Commenter Affiliation: Eastman Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3669-A2

Comment Excerpt Number: 50

Comment: More flexibility is needed for sources wanting to use more comprehensive fuel analysis to demonstrate compliance with emissions averaging.

Section 63.7522(f)(1) requires a source to determine the monthly emission rate from each unit participating in an emissions average. For those units using fuel analysis rather than performance testing, a source must use the applicable equation from §63.7530(c), which requires calculation of the 90th percentile confidence level based on a monthly composite sample made up of a minimum of three grab samples taken at 10-day intervals with each grab consisting of two pounds of coal taken from the coal belt in a 6 inch wide sample of the full cross-section.

While this requirement to use the 90th percentile may be appropriate if a source is using such a limited sampling program, it is entirely inappropriate and ultra-conservative for a source using a much more comprehensive sampling program. Eastman, for example, analyzes composite samples (taken at the supplier yard using ASTM automated sampling methods) of each shipment of coal from each of its suppliers. For one of Eastman's powerhouses, this program produced 264 composite samples in 2011. In a case like this, use of the monthly average concentrations should be allowed instead of the 90th percentile.

Eastman requests the final rule include the option for a source to request an alternative equation and sampling program to be approved in a site-specific emissions averaging plan. One way to accomplish providing this flexibility is to add the following provision in the definition of Er (emission rate) in equations 3a and 3b to §63.7522:

...Determine the emission rate for particulate matter, hydrogen chloride, or mercury by performance testing, according to Table 5 to this subpart, or by fuel analysis for hydrogen chloride or mercury using the applicable equation in §63.7530(c). Alternative equations and sampling and analytical plans for determining emission rate by fuel analysis may be proposed to

and approved by the applicable delegated authority as part of the implementation plan for emissions averaging required in to §63.7522(g).

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 62

Comment: Procedures are needed to assure single events do not cause longer term averages to be exceeded day after day.

Many of the proposed numerical emission limits are rolling averages over extended periods, typically 10 days. Because numerical limits are low, a single event will often cause the rolling average to exceed the limit for the entire 10-day averaging period. Thus, a single event can cause 10 deviations rather than 1 deviation. 22

[Footnote 22: If the event extends over more than one day the average could exceed the limit for more than 10 days.]

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 27

Comment: While a 3-year compliance time could be feasible if only a few boilers needed to implement emissions controls, because of the sheer number of sources that will be competing for resources and the time it will take to successfully complete these emissions reduction projects will mean that many affected facilities will need up to 5 years to implement their projects. Boiler MACT will require a stepwise compliance program given the multiple controls for multiple pollutants. For example, after preliminary testing, if a CO reduction strategy is developed that requires state permit revisions, but then further analysis reveals conflicts with PM, HCl, or mercury, this will require a different CO strategy to maximize reductions across the suite of pollutants. Finally, facilities will need up to six months prior to the compliance date to undertake testing, identify problems, make adjustments to equipment and/or operations, and even retest to verify improvements.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Paul Noe
Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.
Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1
Comment Excerpt Number: 29

Comment: There is precedent for extended compliance schedules for MACT regulations. For example, the pulp and paper industry had staggered MACT compliance deadlines for pulping source under Subpart S, with "phase 2" compliance due 8 years after publication of the final rule. As part of this process, facilities were required to establish timelines for compliance as well as provide updates and submit reports for certain milestones in the rule, to demonstrate progress.

More recently, in the MATS rule for the power sector, EPA acknowledged that many existing sources likely will need more than 3 years of compliance time, but took only limited and ineffective steps to provide the needed relief. EPA explained in the preamble to the rule and in a companion Presidential memorandum that the 1-year case-by-case MACT extension provision should be made broadly available to affected sources – but neither the Agency nor the President exercised available CAA authority to provide such extensions. In addition, the enforcement office issued a memorandum explaining that, in certain highly prescribed circumstances, an additional one-year "extension" might be made available through the use of administrative enforcement orders.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

109A. Remove Emission Averaging 10% Penalty [DENIED PETITIONER ISSUE]

Commenter Name: Peter Pagano
Commenter Affiliation: American Iron and Steel Institute (AISII)
Document Control Number: EPA-HQ-OAR-2002-0058-3490-A1
Comment Excerpt Number: 34

Comment: The rule should not include a 10% penalty for opting to use averaging.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Kevin G. Desharnais, Attorney, Mayer Brown LLP
Commenter Affiliation: United States Sugar Corporation
Document Control Number: EPA-HQ-OAR-2002-0058-3496-A1
Comment Excerpt Number: 12

Comment: The Reconsideration Proposal fails to address US Sugar objections to the ten percent discount factor applied to facilities that utilize emissions averaging. USEPA's justification of the ten percent discount factor, set forth in the preamble to the Final Rule, is incongruous with the

provision's origin and purpose. U.S. Sugar requests that EPA reconsider and eliminate the ten percent discount factor.

In EPA's response to the comments, it explained that the "legal basis and rationale for emissions averaging were provided in the preamble to the final Hazardous Organic NESHAP (59 FR 19425, April 22, 1994)." See EPA's Responses to Public Comments on EPA's *National Emission Standards/or Hazardous Air Pollutants/or Major Source Industrial Commercial Institutional Boilers and Process Heaters*, p. 975. However, EPA itself discouraged reliance upon that rule when it stated in the HON preamble: "the HON emissions averaging system, and its provisions for interpollutant trading, should not be viewed as setting a precedent for future MACT standards." 59 Fed. Reg. at 19425.

EPA also provided the following explanation for its emissions averaging provision in the Final Rule:

Averaging across affected units in the same subcategory is permitted only if it can be demonstrated that the total quantity of any particular HAP that may be emitted by that portion of a contiguous major source that is subject to the NESHAP will not be greater under the averaging mechanism than it would be if each individual affected unit complied separately with the applicable standard.

See EPA's Responses to Public Comments on EPA's *National Emission Standards for Hazardous Air Pollutants for Major Source Industrial Commercial Institutional Boilers and Process Heaters*, p. 975. But nowhere has EPA provided support for the necessity of a discount factor to achieve this stated goal, let alone for the particular ten percent discount factor selected. Basic math can demonstrate whether over-compliance with the standards at one boiler, coupled with under-compliance at another boiler, results in equal emissions reductions to those achieved by obtaining minimum compliance at each boiler. No discount factor is necessary to ensure the emissions reduction is equal under either the emissions averaging or the individual boiler compliance approach. And if any discount factor were appropriate, there has been no showing that a ten percent factor is reasonable.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Kevin G. Desharnais, Attorney, Mayer Brown LLP

Commenter Affiliation: United States Sugar Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3496-A1

Comment Excerpt Number: 13

Comment: Although relying upon the Hazardous Organic NESHAP (HON) rule to support its ten percent discount factor, EPA overlooks that the HON rule did not universally apply the factor. Rather, the rule contained an exception for emissions reductions obtained through pollution prevention measures. See 59 Fed. Reg. at 19431 ("Credits generated through use of a pollution prevention measure need not be discounted, because the EPA recognizes that encouraging pollution prevention will result in more overall emission reductions, possibly including multimedia reductions and lower overall releases into the environment"). EPA's boiler MACT rule contains no similar provision. The HON rule defined "pollution prevention measure"

broadly. In that rule, EPA explained that "[f]or the purposes of the rule, the EPA is referring to any pollution prevention activities described in the Agency's Pollution Prevention Strategy (56 FR 7849) that are applicable to this industry." *Id.*

The Pollution Prevention Strategy outlines a wide variety of pollution prevention measures, including "[i]ncreasing reliance on clean renewable energy sources or alternative, less polluting fuels." 56 FR 7849. Because bagasse is a by-product of the sugar processing industry, it is among the most renewable of energy sources. According to the terms of EPA's Pollution Prevention Strategy, its use should be encouraged.

Therefore, U.S. Sugar requests EPA reconsider its ten percent discount factor for facilities that choose to achieve compliance with the new rule by averaging their emissions. In reconsidering the ten percent discount factor, we renew our request that EPA solicit comments on whether the factor should be applied universally or whether, as required by the HON rule, the use of pollution prevention measures, including the use of renewable fuels, should be excepted from the provision.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: David A. Buff, Golder Associates Inc.
Commenter Affiliation: Florida Sugar Industry (FSI)
Document Control Number: EPA-HQ-OAR-2002-0058-3504-A1
Comment Excerpt Number: 59

Comment: FSI continues to object to the 10-percent emission "penalty" for using the emissions averaging provision. This penalty is unnecessary and overly restrictive. The emission averaging provision, without the 10-percent penalty, would achieve reductions in HAP emissions that are equivalent to the reductions afforded by the MACT limits as applied separately to each boiler.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Lorraine Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1
Comment Excerpt Number: 49

Comment: Emissions averaging with no 10% penalty should be allowed if CEMS are used.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Chris M. Hobson
Commenter Affiliation: Southern Company
Document Control Number: EPA-HQ-OAR-2002-0058-3520-A1
Comment Excerpt Number: 12

Comment: EPA should not discourage facility averaging by requiring a discount factor. The CAA provides EPA broad authority to regulate sources, instead of individual units. See Cong. Rec. S16927; see also 42 U.S.C. § 7412(d) (CAA § 112(d)). Tightening the standards by any percentage for sources that choose to average emissions makes an impossible compliance situation even worse. There is no legitimate reason for imposing a discount factor for sources seeking to average emissions of multiple units. In the final Utility MACT, EPA concluded that "emissions averaging represents an equivalent, more flexible, and less costly alternative to controlling certain emission points to MACT levels" and that averaging "would not lessen the stringency of the MACT floor limits and would provide flexibility in compliance, cost and energy savings to owners and operators."⁷ EPA therefore determined that the use of a discount factor was unwarranted. Given that both the Utility MACT and the IB MACT are being adopted under § 112, and given the similarity of the source categories, there is no obvious reason for fundamentally different approaches in the two rules. EPA should not require a discount factor for sources that choose to average emissions across multiple sources at a plant site.

[Footnote]

(7) 77 Fed. Reg. at 9385

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 79

Comment: Emissions averaging should be allowed and the 10 percent discount factor should be eliminated, particularly where a source is using CEMS or sorbent traps for all emissions units in an emissions averaging scheme for a particular pollutant. EPA provides the following rationale in the MATS preamble⁴² for not requiring a discount factor when sources use CEMS in their emissions averaging approach, and the same rationale applies under this rule:

"The rule allows EGUs that rely on CEMS for compliance demonstrations to be able to participate in emissions averaging and the emissions limits are not subject to a discount. The EPA believes that the data certainty provided by units that use CEMS would be ideal for emissions averaging and the flexibility and cost-effectiveness it offers. Given the homogeneity of fuels within the rules subcategories, along with other emissions averaging criteria, the Agency believes use of a discount factor to be unwarranted for this rule."

[Footnote 42: 77 Fed. Reg. 9386.]

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 92

Comment: Emissions averaging with no 10% penalty should be allowed if optional Hg CEMS are used.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: John M. Cullen

Commenter Affiliation: Masco Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3661-A2

Comment Excerpt Number: 10

Comment: Masco notes that EPA has not changed its position with regard to the 10% discount factor on emission averaging. Emission averaging is an important compliance tool and EPA should continue to include this opportunity in the rule while eliminating the 10% discount factor limitation.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Steve Gossett

Commenter Affiliation: Eastman Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3669-A2

Comment Excerpt Number: 48

Comment: The 10 percent discount factor should be deleted where a source is using CEMS or sorbent traps for all emissions units in an emissions average. EPA's logic for not requiring use of a discount factor in the Utility MACT is shown below:

(63 FR page 450 of prepublication) The rule allows EGUs that rely on CEMS for compliance demonstrations to be able to participate in emissions averaging and the emissions limits are not subject to a discount. The EPA believes that the data certainty provided by units that use CEMS would be ideal for emissions averaging and the flexibility and cost-effectiveness it offers. Given the homogeneity of fuels within the rules subcategories, along with other emissions averaging criteria, the Agency believes use of a discount factor to be unwarranted for this rule.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Douglas A. McWilliams

Commenter Affiliation: American Municipal Power

Document Control Number: EPA-HQ-OAR-2002-0058-3685-A2

Comment Excerpt Number: 44

Comment: Emissions Averaging Should Not Be Subject To a Ten Percent Penalty

AMP supports EPA's continued inclusion of emissions averaging as a flexible compliance alternative for facilities with multiple units. Emissions averaging requires overall compliance with the MACT standards, and thus protects human health and the environment while also lowering costs and increasing flexibility for the regulated community. However, AMP does not support the continued inclusion of a ten percent penalty factor for sources choosing to demonstrate compliance through emissions averaging. This penalty erodes the very compliance flexibility that emissions averaging is designed to create. Despite multiple rounds of rulemaking, EPA still has not offered a rational explanation for why the penalty is necessary to uphold the stringency of the MACT floor.

EPA has included emissions averaging provisions in other rules without imposing a ten percent penalty. In the 2004 version of the Boiler MACT rule, EPA included emissions averaging provisions that were substantially similar to those in the Proposed Rule, but did not include a penalty for utilizing this compliance alternative.⁴⁵ Similarly, EPA is allowing units equipped with CEMS to participate in emissions averaging under the Utility MACT rule with no penalty.

EPA has never explained why such a penalty is necessary to ensure compliance with the MACT limits, and its failure to do so in light of the 2004 Boiler MACT rule, make the penalty provision in the Proposed Rule arbitrary and capricious. The Proposed Rule already contains safeguards to prevent the "backsliding" that may otherwise occur when emissions averaging is employed. Averaged sources must: (1) demonstrate that the emission rate achieved during the compliance test does not exceed the emission rate that was being achieved at a set time after publication of the final rule; (2) demonstrate that the control equipment used during the compliance test is no less effective than it was at the same set time, and; (3) develop and submit an emissions averaging implementation plan for approval. Furthermore, sources demonstrating compliance through emissions averaging must test annually regardless of test results, and must demonstrate compliance on a monthly basis. These requirements are already more stringent than the requirements for units that are not using emissions averaging, and they are sufficient to ensure compliance with the MACT limits.

[Footnote 45: *See, e.g.*, 69 Fed. Reg. at 55257.]

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

109B. Allow Emission Averaging Across Subcategories [DENIED PETITIONER ISSUE]

Commenter Name: Peter Pagano

Commenter Affiliation: American Iron and Steel Institute (AISI)

Document Control Number: EPA-HQ-OAR-2002-0058-3490-A1

Comment Excerpt Number: 33

Comment: Some affected units involve multiple boilers operating in different subcategories (*e.g.*, coal and biomass, coal and natural gas). These boilers are generally located in separate powerhouses and have separate stacks. The goal of emissions averaging is to allow facilities to over-control some emissions points while under-controlling others, thus achieving the required

reductions in the most cost-effective manner possible. This could be best achieved by EPA removing the restriction (or clarifying its intent) to permit averaging for all affected units, regardless of whether the boilers emit through separate or "common stacks." It also has corresponding environmental benefits, by creating an incentive to burn more natural gas or renewable fuels such as biomass as a strategy to average out emissions from coal-fired units. As EPA explained in the Boiler MACT, emissions averaging does not result in higher total HAP emissions than those permitted under the Rule, and therefore there is no additional risk to human health or the environment. The rule should allow for averaging across all units regardless of category or fuel type.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Dirk J. Krouskop

Commenter Affiliation: MeadWestvaco Corporation (MWV)

Document Control Number: EPA-HQ-OAR-2002-0058-3493-A1

Comment Excerpt Number: 13

Comment: MWV is supportive of EPA's inclusion of emission's averaging and common stack provisions. Incorporating emissions averaging into the Boiler MACT is a proper way to encourage flexibility and cost savings for affected facilities. MWV does, however, believe that EPA has the discretion to broaden its view and should allow averaging across different subcategories within a given facility.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 143

Comment: In summary, EPA has not adequately justified its decision to restrict averaging to subcategories and should remove this restriction, especially as it applies to coal-fired boilers. Otherwise, the intent of the provision to provide for flexibility and cost-effective solutions will be thwarted.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Steve Gossett

Commenter Affiliation: Eastman Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3669-A2

Comment Excerpt Number: 46

Comment: EPA has not adequately justified its decision to restrict averaging to subcategories and should remove this restriction, especially as it applies to coal-fired boilers. Otherwise, the intent of the provision to provide for flexibility and cost-effective solutions will be thwarted.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Allison Watkins, Baker Botts

Commenter Affiliation: Class of '85 Regulatory Response Group

Document Control Number: EPA-HQ-OAR-2002-0058-3608-A1

Comment Excerpt Number: 9

Comment: The Class of '85 supports the use of emissions averaging as an important tool for compliance flexibility. Emissions averaging is an equivalent, more flexible, and less costly alternative to controlling emissions. The use of averaging does not reduce the stringency of the maximum achievable control technology (“MACT”) limits; it provides flexibility in compliance and promotes cost and energy savings. However, EPA’s prohibition on the use of emissions averaging for units in different subcategories and for units using CEMS or PM CPMS frustrates the purposes of an emissions averaging option. The Group urges EPA to eliminate these restrictions.

The Major Source Rule unnecessarily restricts the use of emissions averaging among units in different subcategories. Averaging across subcategories could be accomplished by requiring the units to develop an emissions averaging plan, similar to the plan required for NO_x emissions averaging under the Acid Rain Program at 40 C.F.R. § 76.11. The NO_x averaging provisions allow units meeting different NO_x standards to collectively average their emissions and demonstrate compliance either individually or collectively using Btu-weighted annual average emission rates. EPA could develop an approach based on a similar methodology, which would allow more affected facilities to take advantage of the regulatory flexibility provided by the emissions averaging option. For example, multiple regulated units in different subcategories may vent to a combined stack, where only the averaged emission rate could be readily measured. Without the option of emissions averaging, these facilities must shut down units to conduct stack tests for each unit in isolation. This expensive and inefficient procedure is exactly the type of result the emissions averaging option is designed to avoid.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Timothy Serie

Commenter Affiliation: American Coatings Association (ACA)

Document Control Number: EPA-HQ-OAR-2002-0058-3502-A1

Comment Excerpt Number: 16

Comment: ACA generally supports the following proposed changes in the Boiler MACT rule: Incorporation of an emissions averaging provision into the emissions standard.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Eric Guelker, Alliant Energy Corporate Services, Inc.

Commenter Affiliation: Interstate Power and Light Company (IPL) and Wisconsin Power and Light Company (WPL), Alliant Energy Corp.

Document Control Number: EPA-HQ-OAR-2002-0058-3492-A1

Comment Excerpt Number: 4

Comment: Alliant Energy supports emissions averaging as an important option for flexibility of compliance demonstration. EPA should expand the use of averaging to any impacted units under this rule at a given facility. Furthermore, there should not be any restrictions on the ability to average HAP emissions. Currently, it would not be allowed for units that apply continuous emissions monitoring systems (CEMS) or particulate monitoring (PM) continuous parametric monitoring systems (CPMS).

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Allison Watkins, Baker Botts

Commenter Affiliation: Class of '85 Regulatory Response Group

Document Control Number: EPA-HQ-OAR-2002-0058-3608-A1

Comment Excerpt Number: 11

Comment: Similarly, the Proposal clarifies that emissions averaging may not include units using CEMS or PM CPMS. 14 This restriction penalizes sources with multiple regulated units that vent to a combined stack. In these circumstances, the only location to install a CEMS or PM CPMS is the common stack, which would foreclose emissions averaging for all connected units even if emissions averaging would otherwise be available for these units. This result runs counter to the purpose behind the emissions averaging option. Accordingly, the Group requests that EPA delete the restrictions on the emissions averaging provisions and allow units in different subcategories and units using CEMS or PM CPMS to be part of an emissions averaging plan.

[Footnote 14: The Group specifically requests that averaging be allowed for CO emissions, if EPA chooses to adopt limits for this pollutant.]

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Steve Gossett

Commenter Affiliation: Eastman Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3669-A2

Comment Excerpt Number: 44

Comment: Averaging for PM across solid fuel subcategories should be allowed.

In the March 21, 2011, final rule, EPA allowed any solid fuel units at a given facility to use averaging to comply with the Hg, PM, and HCl standards. Now, in the reconsidered proposed rule, EPA has reverted to the case where solid fuel units in different subcategories with different PM emission standards are not allowed to use emissions averaging (*see* §63.7522(b)(3)).

Such restriction on the use of emissions averaging is arbitrary and will only serve to increase the cost of the final rule. While EPA claims the commenters gave no justification for allowing averaging across subcategories, that is not the case as is reflected in the excerpt below from Eastman's comments:

On page 32034 of the preamble, EPA states one of its limits on the scope of emissions averaging is to not allow averaging between sources that are not part of the same affected source. In this case, EPA has elected to define the affected source in §63.7490(a)(1) as all units within a subcategory. We see no reason for EPA to use this definition. Rather all units at a given facility subject to the subpart should be collectively considered the "affected source". This is how EPA has defined the term in other rules with which we are familiar (e.g. the HON in Subpart F, Polymer and Resins 4 in Subpart JJJ, the MON in Subpart FFFF). The HON in particular we understand is the model EPA is using to guide its policy. By defining the term affected source as all chemical manufacturing process units (CMPUs) at a facility, the HON allows emissions averaging across CMPUs and across emission unit types (vents, storage vessels, transfer racks, wastewater stream). There is no reason in the boiler and process heater MACT for EPA to restrict the emissions averaging alternative as it has proposed. To do so, will prevent some facilities from taking advantage of the opportunity to avoid otherwise cost-prohibitive compliance options by over-controlling some other emission unit in a more cost-effective combination.

Also, by not allowing averaging across the different fuel categories, EPA removes an incentive to burn more natural gas or renewable fuels such as biomass as a strategy to average out emissions from a coal-fired unit.

EPA states in its response that allowing averaging across mixed streams (i.e. subcategories) would be swaying from its precedent. Just the opposite is true: the HON, which is the emissions averaging precedent setting rule, allows emissions averaging across different types of emissions units from different chemical manufacturing process units. It does not allow averaging across different pollutants – which Eastman is not suggesting EPA allow in the Boiler MACT. The preamble to the HON Final Rule (Federal Register, April 22, 1994, starting on page 19425) provides EPA's rationale for the emissions averaging provisions. It states that the Agency has broad discretion to define "source." In the case of the HON, "source" is defined as all emission points relating to SO₂ production at a facility. It allows all emission points that have numerical emission standards to participate in an average. Process vents, storage vessels, transfer rack, and wastewater streams are all allowed in the emissions average and they all have differing emission standards. Only equipment leaks, which have no defined allowable emission level, are excluded. Accordingly, EPA has all the latitude it needs to allow emissions averaging across all units at a given facility that are subject to Subpart DDDDD, so long as they have an applicable numeric emission limit.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Lorraine Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1
Comment Excerpt Number: 140

Comment: AVERAGING FOR PM ACROSS SOLID FUEL SUBCATEGORIES SHOULD BE ALLOWED.

In response to comments received on the 2010 Proposed Boiler Rule that emissions averaging should be allowed across subcategories, EPA stated:

"While EPA did not make major adjustments to the emissions averaging provisions, the change to a solid fuel subcategory will enable all solid fuel-fired units at a facility to use the emissions averaging provision for Hg, PM, and HCl. Beyond this, EPA disagrees that it is appropriate to average across subcategories for affected sources with mixed streams (e.g. SOCFI) and the commenter does not provide sufficient justification for swaying from this precedent." (see Response to Comments Document (Document Control Number EPA-HQ-OAR-2002-0058-3137.1))

In the Final Boiler Rule, EPA allowed any solid fuel units at a given facility to use averaging to comply with the Hg, PM, and HCl standards. Now, in the Reconsidered Proposal, EPA has reverted to the case where solid fuel units in different subcategories with different PM emission standards are not allowed to use emissions averaging (*see* §63.7522(b)(3)).

Such restriction on the use of emissions averaging is arbitrary and will only serve to increase the cost of the final rule. While EPA claims the commenters gave no justification for allowing averaging across subcategories, that is not the case as is reflected in the excerpt below from comments submitted by the Eastman Chemical Company, an ACC member:

On page 32034 of the preamble, EPA states one of its limits on the scope of emissions averaging is to not allow averaging between sources that are not part of the same affected source. In this case, EPA has elected to define the affected source in §63.7490(a)(1) as all units within a subcategory. We see no reason for EPA to use this definition. Rather all units at a given facility subject to the subpart should be collectively considered the "affected source". This is how EPA has defined the term in other rules with which we are familiar (e.g. the HON in Subpart F, Polymer and Resins 4 in Subpart JJJ, the MON in Subpart FFFF). The HON in particular we understand is the model EPA is using to guide its policy. By defining the term affected source as all chemical manufacturing process units (CMPUs) at a facility, the HON allows emissions averaging across CMPUs and across emission unit types (vents, storage vessels, transfer racks, wastewater stream). There is no reason in the boiler and process heater MACT for EPA to restrict the emissions averaging alternative as it has proposed. To do so, will prevent some facilities from taking advantage of the opportunity to avoid otherwise cost-prohibitive compliance options by over-controlling some other emission unit in a more cost-effective combination.

Also, by not allowing averaging across the different fuel categories, EPA removes an incentive to burn more natural gas or renewable fuels such as biomass as a strategy to average out emissions from a coal-fired unit.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 77

Comment: Additional flexibility should be incorporated into the proposed emissions averaging provisions in order to ensure facilities have options to reduce the cost of compliance. Boilers of any design firing any fuel (e.g., in any subcategory) should be included in the emissions averaging provisions and facilities should not be limited to use of emissions averaging only for boilers in the same subcategory. There is no justification for restricting emissions averaging only to boilers in a specific subcategory; facilities should be able to average emissions from stoker boilers with emissions from pulverized coal boilers and liquid boilers. This approach has been used in several other rules. For example, the Pulp and Paper Chemical Recovery Combustion MACT and the HON allow emissions averaging across different types of units. The equivalency by permit provisions under 40 CFR 63.94 allow sources to "trade" emissions from unregulated sources for emissions of regulated sources, so this is an additional reason not to restrict use of emissions averaging to boilers within the same subcategory.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Steve Gossett

Commenter Affiliation: Eastman Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3669-A2

Comment Excerpt Number: 40

Comment: Heretofore, the Agency has expressed its concern that it may lacks authority to allow averaging across subcategories or that such allowance would be inconsistent with its policy in providing emissions averaging options in other rules., However, as discussed in the preamble to the HON (Hazardous Organic NESHAP for the Synthetic Organic Chemicals Manufacturing Industry (SOCMI) (Federal Register, April 22, 1994, starting on page 19425)), the rule EPA cites as precedent for emissions averaging, EPA has itself acknowledged its wide discretion to define “source” broadly. Indeed, in the case of the HON, EPA defined the source category to include all emission points relating to SOCMI production at a facility – a range of emission points and technologies far more diverse than the differences between coal-fired and converted coal-to- gas boilers. The HON allows all emission points that have numerical emission standards to participate in an emissions average. Process vents, storage vessels, transfer rack, and wastewater streams are all allowed in the emissions average and they all have differing emission standards. Only equipment leaks, which have no defined allowable emission level, are excluded.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Peter Pagano
Commenter Affiliation: American Iron and Steel Institute (AISI)
Document Control Number: EPA-HQ-OAR-2002-0058-3490-A1
Comment Excerpt Number: 35

Comment: There is precedent in MACT standards for allowing averaging across different types of units of a single source. For example, the HON Rule allows process vents, storage vessels, transfer racks, and wastewater streams all to be included in an emission average across an affected source.⁴² EPA reasoned that averaging needed to be allowed across all emission points (except equipment leaks) to provide as much flexibility as possible while maintaining an enforceable emission limitation.⁴³ Similar mechanisms have been adopted in other MACT standards.⁴⁴ The same considerations apply here.

EPA should allow long-term averaging across all affected units regardless of fuel type.

[Footnote]

(42) 40 C.F.R. Subpart G.

(43) 59 Fed. Reg. 19,425 (Apr. 22, 1994).

(44) *See, e.g.*, Petroleum Refinery NESHAP, 60 Fed. Reg. 43,244, 43,254 (Aug. 18, 1995) (allowing wide range of emission sources to be averaged, noting that "EPA has the flexibility to allow trading within a facility that includes units in different source categories"); Boat Manufacturing NESHAP, 66 Fed. Reg. 44,218, 44,232 (Aug. 22, 2001)

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Lorraine Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1
Comment Excerpt Number: 141

Comment: If EPA is concerned that it cannot allow emissions averaging across subcategories because the subcategories have different emission standards, this concern is easily addressed. As in the HON, the compliance methodology can easily accommodate subcategories with different emission limits for a given pollutant. This is done by calculating debits and credits and assuring that credits (after discount) are equal to or greater than debits (*see* §63.150(e)). An example is provided below to demonstrate this concept:

A facility has one pulverized coal (PC) boiler with a rated capacity of 500 mmBtu/hr and a PM emission rate of 0.07 lb/mmBtu and one stoker boiler with a rated capacity of 250 mmBtu/hr and a PM emission rate of 0.07 lb/mmBtu. Both of these boilers exceed their respective PM emission standards of 0.044 lb/mmBtu and 0.028 lb/mmBtu. The stoker is older, smaller, and much more difficult to retrofit and use of a fabric filter poses a safety hazard (due to sparks). In order to conserve capital (which it can use for growth projects and assist with the nation's economic recovery), the facility would like to install a state-of-the art fabric filter (with a PM emission rate

of 0.01 lb/mmBtu) on the PC boiler and avoid a capital investment on the stoker. If the rule were to allow averaging, the credits and debits based on rated heat input capacities would be determined as follows (likewise, each month, the credits and debits are calculated based on actual heat inputs for that month for each unit in the average and a twelve month rolling sum of credits vs. debits is recorded):

Credits from PC Boiler = $0.9 * [500 \text{ mmBtu/hr} * (0.044 - 0.01 \text{ lb/mmBtu})] * 720 \text{ hours/month} = 11,016 \text{ lbs}$

Debits from Stoker Boiler = $[250 \text{ mmBtu/hr} * (0.07 - 0.028 \text{ lb/mmBtu})] * 720 \text{ hours/month} = 7,560 \text{ lbs}$

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Steve Gossett

Commenter Affiliation: Eastman Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3669-A2

Comment Excerpt Number: 45

Comment: If EPA is concerned that it cannot allow emissions averaging across subcategories because the subcategories have different emission standards, this concern is easily addressed. As in the HON, the compliance methodology can easily accommodate subcategories with different emission limits for a given pollutant. This is done by calculating debits and credits and assuring that credits (after discount) are equal to or greater than debits (*see* §63.150(e)). An example is provided below to demonstrate this concept:

A facility has one pulverized coal (PC) boiler with a rated capacity of 500 mmBtu/hr and a PM emission rate of 0.07 lb/mmBtu and one stoker boiler with a rated capacity of 250 mmBtu/hr and a PM emission rate of 0.07 lb/mmBtu. Both of these boilers exceed their respective PM emission standards of 0.044 lb/mmBtu and 0.028 lb/mmBtu. The stoker is older, smaller, and much more difficult to retrofit and use of a fabric filter poses a safety hazard (due to sparks). In order to conserve capital (which it can use for growth projects and assist with the nation's economic recovery), the facility would like to install a state-of-the-art fabric filter (with a PM emission rate of 0.01 lb/mmBtu) on the PC boiler and avoid a capital investment on the stoker. If the rule were to allow averaging, the credits and debits based on rated heat input capacities would be determined as follows (likewise, each month, the credits and debits are calculated based on actual heat inputs for that month for each unit in the average and a twelve month rolling sum of credits vs. debits is recorded):

Credits from PC Boiler = $0.9 * [500 \text{ mmBtu/hr} * (0.044 - 0.01 \text{ lb/mmBtu})] * 720 \text{ hours/month} = 11,016 \text{ lbs}$

Debits from Stoker Boiler = $[250 \text{ mmBtu/hr} * (0.07 - 0.028 \text{ lb/mmBtu})] * 720 \text{ hours/month} = 7,560 \text{ lbs}$

Eastman is not suggesting units that have no numerical emission standard be included in an emissions average. A numerical emission standard is required in order to calculate credits and

debits as in the HON precedent. Therefore, a unit designed to burn gas 1 could not be included in an emission average unless (as we have commented elsewhere) it was in a subcategory with an applicable numerical emission limit as of the date of proposal. In that case, the unit's credits are determined by the difference in the emission profile proposed above (i.e. three times the detection limit of the applicable reference method) from the converted gas unit and the applicable emission rate limit defined for that unit as it existed on the date of proposal (multiplied times its heat input or steam load).

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 142

Comment: We are not suggesting units that have no numerical emission standard be included in an emissions average. A numerical emission standard is required in order to calculate credits and debits as in the HON precedent. Therefore, a unit designed to burn gas 1 could not be included in an emission average unless (as we have commented elsewhere) it was in a subcategory with an applicable numerical emission limit as of the date of proposal. In that case, the unit's credits are determined by the difference in the emission profile proposed above (i.e. three times the detection limit of the applicable reference method) from the converted gas unit and the applicable emission rate limit defined for that unit as it existed on the date of proposal (multiplied times its heat input or steam load).

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Impacts Analysis

15Z. Out of Scope: Impacts Analysis

Commenter Name: Regina Hopper

Commenter Affiliation: America's Natural Gas Alliance (ANGA)

Document Control Number: EPA-HQ-OAR-2002-0058-3444-A1

Comment Excerpt Number: 5

Comment: ANGA believes that this rule, like other rules promulgated by the Agency, should reflect the use of the best data and science that is available, and that the ongoing reconsideration presents an opportunity for EPA to do so. As part of its reconsideration, we request that the Agency look more closely at its analysis of both the capital costs and operating costs of fuel switching. For example, in its 2010 Cost Memorandum, the Agency claimed that its regulatory requirements for multiple post-combustion controls on coal-fired boilers would achieve roughly the same emissions reductions as switching to gas (2010 Cost Memo, Appendix A-7); however,

it never compared the \$4.5 billion capital cost for those controls³ to its capital cost figure of \$1.171 billion for the capital cost of fuel-switching to natural gas.

We also repeat our request that the Agency look more closely at that \$1.171 billion capital cost for fuel switching in the 2010 Cost Memo. We continue to believe that using cost data from one 1986 feasibility study that is actually based on converting oil, not coal fired boilers, is inappropriate for purposes of estimating costs in 2010-2011. Furthermore, our analysis suggests that the boiler conversions that were the subject of the 1986 feasibility study all involved conversions from oil-to-gas, not coal-to-gas, and that the Agency may have inadvertently included a separate cost estimate -- not actual costs -- for one of those three boilers as the fourth "conversion".

Finally, with respect to operating costs, ANGA requests that as part of its reconsideration process, EPA revisit the price of natural gas that it used in its analysis. **In** its cost analysis for the ICI Boiler MACT Rules the Agency used a gas price of \$11.66 per MMBtu; however, in the cost analysis in the Technical Support Document that the Agency published for its proposed utility EGU MACT -- which was signed two weeks after the ICI Boiler MACT Rules were finalized -- it used \$5.74 per MMBtu. ANGA suggests that the Agency look to more recent price data⁴, including its own contemporaneous data, to support a more robust cost analysis for the ICI Boiler MACT Rules.

[Footnotes]

(3) *See*, Regulatory Impact Analysis, p. 3-2.

(4) e.g. Henry Hub and NYMEX data showing prices will stay low and stable

http://www.eia.gov/dnav/ng/ng_prLfut_sl_d.htm

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Michael D. Wendorf

Commenter Affiliation: FMC Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3453-A1

Comment Excerpt Number: 9

Comment: Additionally, this combustion environment is counter to good energy efficiency; the additional combustion air that will be heated in the furnace will not produce additional steam but will waste fuel. The add-on NO_x controls will also increase energy consumption per unit of steam produced.

FMC requests EPA to consider retaining the existing CO limits for PC-coal units as specified in the final rule. The existing CO limits provide an opportunity *to* balance existing NO_x compliance obligations with the desired initiatives of the MACT Rule.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: John S Williams
Commenter Affiliation: Maine Pulp & Paper Association (MPPA)
Document Control Number: EPA-HQ-OAR-2002-0058-3466-A1
Comment Excerpt Number: 1

Comment: MPPA's members (the "Maine Mills") are very concerned with the potential cost impacts of the Boiler MACT regulation. Our members estimate that compliance with the Boiler MACT rule would cost MPPA's eight Mills well in excess of \$60 million; with compliance costs for certain individual mills in the tens of millions of dollars, and very likely multiples of these amounts if the continued combustion of mill wastewater treatment plant residuals or sludge ("WWTR") in mill boilers triggers applicability of the Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Commercial and Industrial Solid Waste Incineration Units at 40 C.F.R. Part 60, Part CCCC ("CISWI") requirements.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: John S Williams
Commenter Affiliation: Maine Pulp & Paper Association (MPPA)
Document Control Number: EPA-HQ-OAR-2002-0058-3466-A1
Comment Excerpt Number: 7

Comment: The Boiler MACT CO limits would necessitate combinations of emission controls that would have adverse effects on each other, and even then are unachievable for certain biomass boilers at Maine mills.

For example, the conditions that affect the optimum emissions of CO may run contrary to minimizing emissions of NO_x. Although NO_x is not addressed in the Boiler MACT, for years the northeastern states, including Maine, have focused on the control and reduction of NO_x emissions to improve ozone. Minimizing CO emissions conflicts with the State's efforts to minimize NO_x.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Lenny Dupuis
Commenter Affiliation: Dominion Resources Services, Inc.
Document Control Number: EPA-HQ-OAR-2002-0058-3486-A1
Comment Excerpt Number: 11

Comment: Dominion owns and operates an 83 MW biomass facility (consisting of 3 wood-burning boilers) in Hurt, Virginia and is considering additional biomass power investments to enhance its portfolio of renewable and carbon-neutral generation. Such investments will require reasonable environmental regulations that can be met with currently available and economically feasible emissions control technology. As a matter of environmental policy, EPA should encourage the combustion of biomass as substitute fuel for more polluting fuels. The combustion of biomass will become increasingly important to utilities as renewable portfolio standards (RPS)

or targets are adopted by more states and are possibly applied to all states as a result of federal mandates. The combustion of biomass may also have an important role as an option for achieving existing or anticipated greenhouse gas emission (GHG) reduction goals or targets. Biomass power is a key strategy for many utility companies, including Dominion, in the southeastern U.S., since there are more limited renewable energy resources than in other parts of the country. In addition, biomass power utilizing waste wood is currently the lowest-cost commercially available renewable generation option that is also a base-load (dispatchable) generation resource.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Lenny Dupuis

Commenter Affiliation: Dominion Resources Services, Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3486-A1

Comment Excerpt Number: 13

Comment: Emissions of mercury (Hg), dioxin and hydrochloric acid (HCl) are present in very small amounts in wood. Biomass units are inconsequential sources of these HAPs. In addition, the biomass limits are unduly influenced by tests that could not detect some of the hazardous air pollutants to be regulated ("non-detects"). Given these issues and the important role biomass units can have in achieving GHG reduction and RPS targets, biomass units should be given special consideration in this rule.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Dirk J. Krouskop

Commenter Affiliation: MeadWestvaco Corporation (MWV)

Document Control Number: EPA-HQ-OAR-2002-0058-3493-A1

Comment Excerpt Number: 1

Comment: The rule represents a set of air regulatory requirements that impact virtually all manufacturing sectors at a time where the national economy is recovering from a severe economic slump. EPA estimates the cost of the rule to be \$ 5.4 billion, while industry estimates the cost to be \$14.3 billion. MWV believes that EPA has significantly underestimated the costs for retrofitting control systems on the suite of boilers that must be modified to meet these standards. For example, EPA assumes that fabric filters are sufficient to meet the mercury standards, while EPA's database indicates that several units equipped with fabric filters cannot meet these requirements. EPA also assumes that low NO_x burners can be installed on certain units to achieve the carbon monoxide standards imposed by the rules. The technology employed by low NO_x burners tends to lower overall thermal efficiency and thereby increase CO emissions.

These are just a couple of examples where the technologies EPA believes will work may not and thereby increase costs and complexity to individual facilities.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Dirk J. Krouskop

Commenter Affiliation: MeadWestvaco Corporation (MWV)

Document Control Number: EPA-HQ-OAR-2002-0058-3493-A1

Comment Excerpt Number: 2

Comment: These comments, EPA has the legal discretion and technical justification to substantially reduce the burden of the standard while still providing ample protection to health and the environment.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: N.W. Bernstein & Associates, LLC

Commenter Affiliation: Eco Power Solutions (USA) Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3499-A1

Comment Excerpt Number: 7

Comment: Another important rationale for taking the proposed action is that failure to do so (i.e. failure to rescind the original Boiler Rule and propose an entirely new rule (based on the values set forth in the proposed reconsideration) would lock American heavy industry into obsolete, expensive, piecemeal emission control technologies for decades to come. Instead of encouraging the modernization of industrial processes using major industrial boilers, EPA's proposed approach will have the unintended consequences of long term damage to the competitiveness of American heavy industry, with all its implications for loss of jobs and increased trade deficits that must over time increase inflation.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Alicia Meads

Commenter Affiliation: National Association of Manufacturers (NAM)

Document Control Number: EPA-HQ-OAR-2002-0058-3515-A1

Comment Excerpt Number: 2

Comment: Jeopardize critically needed jobs. Some standards in the proposed rules are more stringent than prior iterations of the rules, the total costs of compliance has increased several hundred of million dollars for manufacturers, and some limits may not be achievable, especially within the current three year compliance timeframe. For example, the particulate standards are more stringent for the predominant boilers in the forest products industry (wet biomass stoker boilers). In addition, the EPA has made the standards for coal and coal-biomass boilers significantly more costly. As a result, these proposed rules jeopardize more than 200,000 critically needed jobs.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Roger Martella

Commenter Affiliation: National Alliance of Forest Owners (NAFO)

Document Control Number: EPA-HQ-OAR-2002-0058-3519-A1

Comment Excerpt Number: 1

Comment: Wood from sustainably managed forests provides a renewable, low-carbon alternative to fossil fuels. According to U.S. Energy Information Administration ("EIA") data, biomass already supplies more than 50% of the nation's renewable energy.² Forests can provide ample sustainable, domestic supplies of biomass to produce liquid transportation fuels, electricity, thermal energy (heat and power for manufacturing and other industrial uses), and synthetic natural gas.³

When evaluating the GHG emissions associated with fuels, a lifecycle analysis incorporates all steps in a "product system" to evaluate broader environmental impacts of products and processes. Using forest biomass as a renewable fuel source has significant carbon benefits because its lifecycle GHG emissions are more favorable than those of petroleum and other fossil fuels. For example, the Department of Energy ("DOE") estimates that "[c]ellulosic ethanol use could reduce GHGs by as much as 86%."⁴ In addition, EPA has determined, in conjunction with its Renewable Fuel Standard Program, that the lifecycle GHG emissions reductions associated with cellulosic ethanol may be as much as 92.7 percent.⁵

Lifecycle analyses of biomass feedstocks used for electricity generation have produced similar results.⁶ In addition to reducing GHG emissions through the displacement of fossil fuel, biomass energy can provide additional climate benefits. For example, combusting biomass for energy can avoid emissions of other biogenic GHGs (such as methane) that would result from alternative disposal fates of biomass residues and replace them with lower potency CO₂ emissions from energy production.⁷

Thus the prevailing science – in both the public and private sectors – acknowledges the significant carbon benefits of energy produced using renewable biomass from managed forests.

[Footnote 2: See, EIA, Annual Energy Review (Oct. 19, 2011), available at <http://www.eia.gov/totalenergy/data/annual/showtext.cfm?t=ptb1001>.]

[Footnote 3: See NAFO, Carbon Neutrality of Energy from Forest Biomass, available at <http://nafoalliance.org/carbon-neutrality-of-energy-from-forest-biomass/>.]

[Footnote 4: Department of Energy, Ethanol Benefits, available at <http://www.afdc.energy.gov/afdc/ethanol/benefits.html> (last visited Jan. 30, 2012).]

[Footnote 5: See EPA, DPA420-D-06-008, *Renewable Fuel Standard Program: Draft Regulatory Impact Analysis* at 191 (Sept. 2006).]

[Footnote 6: Cherubini, *et al.*, *Energy- and greenhouse gas-based LCA of biofuel and bioenergy systems: Key issues, ranges and recommendations*, Resources, Conservation and Recycling 535:

434-447 (2009) (90-95% emissions reductions relative to fossil fuel systems); Zhang, *et al.*, *Life cycle emissions and cost of producing electricity from coal, natural gas, and wood pellets in Ontario, Canada*, *Environmental Science and Technology* 44(1): 538-544 (2010) (91% and 78% emissions reductions relative to coal and natural gas systems); Raymer, A.K.P., *A comparison of avoided greenhouse gas emissions when using different kinds of wood energy*, *Biomass and Bioenergy* 30: 605-617 (2006) (81-89% emissions reductions relative to fossil fuel alternatives).]

[Footnote 7: Gregory Morris, *Bioenergy and Greenhouse Gases* (Pacific Institute, 2008), available at [http://www.pacinst.org/reports/Bioenergy and Greenhouse Gases/Bioenergy and Greenhouse Gases.pdf](http://www.pacinst.org/reports/Bioenergy_and_Greenhouse_Gases/Bioenergy_and_Greenhouse_Gases.pdf).]

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Roger Martella

Commenter Affiliation: National Alliance of Forest Owners (NAFO)

Document Control Number: EPA-HQ-OAR-2002-0058-3519-A1

Comment Excerpt Number: 2

Comment: The prevailing view in the science community is that, when forests are managed sustainably, CO₂ emissions from forest biomass are part of the natural carbon cycle and are balanced by carbon sequestration as forests grow. In other words the carbon that enters the atmosphere when forest biomass is combusted was previously absorbed from the atmosphere by the forest biomass and will be reabsorbed when new biomass is grown.

As EPA has concluded, there is "[s]cientific consensus . . . that the CO₂ emitted from burning biomass will not increase total atmospheric CO₂ if this consumption is done on a sustainable basis."⁸ Recognizing that CO₂ emissions from biomass combustion are inextricably tied to the forests where biomass is grown, EPA follows international convention and does not include emissions from biomass combustion in its national emissions totals.⁹ Instead, EPA accounts for CO₂ emissions from biomass combustion by measuring changes in forest carbon stocks over time, recognizing that there is no net climate impact as long as forest carbon stocks are stable or increasing.¹⁰ Similarly, DOE's Voluntary Reporting of Greenhouse Gases Program, authorized by Section 1605(b) of the Energy Policy Act of 1992, provides for exclusion emissions from the combustion of biomass fuels.¹¹

More recently, EPA has affirmed the climate benefits of biomass energy combustion when compared to fossil fuels by reconsidering its treatment of biogenic CO₂ emissions under the Prevention of Significant Deterioration ("PSD") and Title V Programs.¹² Recognizing that imposing regulatory burdens on the biomass energy sector would discourage development of this important renewable fuel supply, EPA has deferred regulation of CO₂ emissions from stationary sources – including boilers and incinerator units – for three years while it seeks to identify a method to quantify the climate benefits offered by biomass energy.¹³ EPA has also convened a Biogenic Carbon Emissions Panel under the auspices of the Science Advisory Board to provide advice and recommendations as EPA completes the reconsideration process.¹⁴

EPA has consistently recognized the climate benefits of biomass energy and is committed to a regulatory approach that rewards bioenergy facilities for the climate benefits that they provide in relation to fossil fuel facilities. EPA must ensure that the treatment of biomass boilers and incinerators under these proposed rules is consistent with its overarching regulatory approach.

[Footnote 8: Environmental Protection Agency Combined Heat and Power Partnership, *Biomass Combined Heat and Power Catalog of Technologies*, 96 (Sept. 2007), available at Recognizing that imposing regulatory burdens on the biomass energy sector would discourage development of http://www.epa.gov/chp/documents/biomass_chp_catalog.pdf.]

[Footnote 9: EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009* 3-59 (April 15, 2011).]

[Footnote 10: *Id.* Chapter 7.]

[Footnote 11: See DOE, *Technical Guidelines: Voluntary Reporting of Greenhouse Gases (1605(b)) Program* (January 2007) at 77 (“Reporters that operate vehicles using pure biofuels within their entity should not add the carbon dioxide emissions from those fuels to their inventory of mobile source emissions because such emissions are considered biogenic and the recycling of carbon is not credited elsewhere.”).]

[Footnote 12: Letter from Gina McCarthy to Roger Martella (Jan. 12, 2011) granting NAFO’s Petition for Reconsideration, available at <http://www.epa.gov/nsr/ghgdocs/McCarthytoMartella.pdf>.] [Footnote 13: Deferral for CO2 Emissions From Bioenergy and Other Biogenic Sources Under the Prevention of Significant Deterioration (PSD) and Title V Programs, 76 Fed. Reg. 43,490 (July 20, 2011).]

[Footnote 14: See generally EPA, Carbon Dioxide Accounting for Emissions from Biogenic Sources, <http://yosemite.epa.gov/sab/SABPRODUCT.NSF/81e39f4c09954fcb85256ead006be86e/2f9b572c712ac52e8525783100704886!OpenDocument> (last visited Jan. 31, 2012).]

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Roger Martella

Commenter Affiliation: National Alliance of Forest Owners (NAFO)

Document Control Number: EPA-HQ-OAR-2002-0058-3519-A1

Comment Excerpt Number: 3

Comment: As described above, forests and forest products can play an important role in reducing and managing GHG emissions. Expanding the sources of renewable energy is a central feature of both national and international policy to reduce reliance on fossil fuels.

EPA, in considering approaches toward addressing climate change, has long recognized that responsibly managed forests are considered one of five key "groups of strategies that could substantially reduce emissions between now and 2030."¹⁵ Similarly, the United Nation’s Intergovernmental Panel on Climate Change ("IPCC") report on mitigation technologies

highlights forest management as a primary tool to reduce GHG emissions.¹⁶ In fact EIA projects that biomass energy will account for 30% of the growth in electricity produced by renewable fuels between now and 2035.¹⁷

President Obama has repeatedly emphasized that renewable energy derived from feedstocks such as forest biomass hold the key to transitioning the nation to a "sustainable, low carbon energy future."¹⁸ Recognizing the benefits of all types of biomass, he recently stated that "another substitute for oil that hold tremendous promise is renewable biomass – not just ethanol, but biofuels made from things like switchgrass and wood chips and biomass."¹⁹ And in last month's State of the Union Address the President advocated an "all-out, all-of-the-above strategy that develops every available source of American energy," specifically referencing a "clean energy standard" that would encourage the development of clean renewable energy including biomass.²⁰

With Presidential endorsement, if not direction, of national renewable energy policy and the role of biomass in that policy, EPA must conduct its programs in manner consistent with that policy. In light of this policy, EPA must avoid mandatory environmental controls, such as those included in the existing Major Source, CISWI, and NHSM rules, that will require large expenditures of time and resources by industry, but are not necessary to protect human health and the environment. Similarly, to act consistently with the nation's renewable energy policy, EPA must not impose restrictions on biomass boilers and incinerator units that are not legally required and will disadvantage the use of biomass as a fuel source. The proposed rules are a significant step in correcting the errors of the existing rules and conforming them to the administration's policies. Still the proposed rules do not go far enough and, as explained below, there are several ways in which the proposed rules can be altered to ensure consistency with the administration's policies and the legal requirements of the Clean Air Act.

[Footnote 16: *Id.* at 44,405-06; *see also*, NAFO, Carbon Mitigation Benefits of Working Forests (identifying trading platforms and registries that recognize forest management), *available at* <http://nafoalliance.org/mitigationbenefits-working-forests/>.]

[Footnote 17: *Annual Energy Outlook 2012 Early Release Overview 7*, *available at* [http://www.eia.gov/forecasts/aeo/er/pdf/0383er\(2012\).pdf](http://www.eia.gov/forecasts/aeo/er/pdf/0383er(2012).pdf).]

[Footnote 18: Letter from President Barack Obama to Governors John Hoeven and Chet Culver (May 27, 2009), *available at* [http://www.governorsbiofuelscoalition.org/assets/files/President%20Obama's@20Response5-27-09.pdf](http://www.governorsbiofuelscoalition.org/assets/files/President%20Obama's%20Response5-27-09.pdf); *see also* President Barack Obama, Memorandum for the Secretary of Agriculture, the Secretary of Energy, and the Administrator of the Environmental Protection Agency, 74 Fed. Reg. 21,531-32 (May 5, 2009).]

[Footnote 19: President Barack Obama, *Remarks by the President on America's Energy Security*, March 30, 2011, *available at* <http://www.whitehouse.gov/the-press-office/2011/03/30/remarks-president-americas-energy-security>.]

[Footnote 20: President Barack Obama, *Remarks by the President in State of the Union Address*, January 24, 2012, *available at* <http://www.whitehouse.gov/the-press-office/2012/01/24/remarks-president-state-union-address>.]

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Roger Martella

Commenter Affiliation: National Alliance of Forest Owners (NAFO)

Document Control Number: EPA-HQ-OAR-2002-0058-3519-A1

Comment Excerpt Number: 5

Comment: Even if EPA properly finalizes the regulations in a way that classifies biomass energy feedstocks as non-waste, this clean, renewable, and climate-beneficial energy supply will not be developed without significant changes to the current emissions limits imposed on biomass boilers under the Major Source rule. Despite the fact that biomass energy is a clean, renewable alternative to fossil fuel combustion, the current regulations impose stringent emissions limits on biomass boilers that will require installation of expensive control technology while providing minimal (and sometimes undetectable) environmental and health benefits. Unless changes are made to the existing emissions limits, the high costs of compliance for biomass boilers will inevitably cause energy producers to turn to fossil fuel alternatives with lower compliance costs.

The proposed changes to the Major Source rule offer a number of improvements that will reduce compliance costs without sacrificing environmental and health benefits, particularly with respect to dioxin/furan emissions limits and the standards for new biomass boilers. However, these changes will not be sufficient to properly encourage and incentivize biomass energy development. NAFO urges EPA to consider additional changes with respect to emissions limits for other HAPs – including particulate matter standards for existing boilers. Without additional changes, future growth in the biomass energy sector will be discouraged and the potential climate benefits of biomass energy will not be fully realized.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 22

Comment: Facilities will need to evaluate the applicability of other environmental regulations when selecting compliance options for the boiler and incinerator rules. For example, a facility cannot implement a CO reduction strategy that will result in a NOX increase if the facility is located in a non-attainment area or implement an air emissions control strategy that has adverse impacts on their water or waste discharges. Depending on the amount of NOX emission increases, the facility could have to go through PSD review, which can take a year or more to complete. Some controls may affect SO2 emissions and with the new short-term SO2 limits, states are frequently requiring extensive dispersion modeling which can take months to complete. Complex dispersion modeling would also be required to evaluate any effects of ammonia injection for NOX controls that are required as a result of lowering CO emissions.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 24

Comment: Formulating the control strategy is just the beginning of a long process to procure and install the necessary equipment. Facilities must get approval for the capital required to implement the controls. As we are in the worst economy in the history of the Clean Air Act, capital planning cycles have been lengthened, and many companies must borrow capital through bank loans which have lengthier review periods. For many facilities, the compliance costs will dominate capital spending for several years, especially in the wood products sector, where little capital will remain for other facility upgrades or even maintenance projects. Since Boiler MACT is the most costly and complex MACT standard ever promulgated for U.S. manufacturers, acquisition of sufficient capital will be a more time consuming enterprise and companies cannot reasonably commit capital until the "final," final rules are in place.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 28

Comment: Regardless of changes to the rule, billions of dollars will be required to comply, and, unlike the electric utilities whose compliance costs will be passed on to all electricity consumers, manufacturers face a globally competitive marketplace. Raising prices can result in loss of customers, which can lead to shut downs and job losses. Additional time to comply will spread out the burden and help maintain a competitive position.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 42

Comment: Most boilers are designed to mix fuel and air at an appropriate ratio, and to provide sufficient residence time (and temperature) for the fuel to combust completely. Obviously, these factors are fuel-dependent, as a gaseous fuel will require less time for complete combustion than a liquid fuel, which in turn requires less time to burn than a solid fuel. The need for longer residence time is why the radiant sections in solid fuel- fired boilers are larger than for gas-fired

units. The size of the boiler is typically optimized to allow for complete combustion, while minimizing the cost of construction materials. If the construction cost were not a concern, a new boiler could be designed with additional residence time to complete the combustion process and minimize CO emissions. For these reasons, the geometry of individual furnaces has a significant impact on the level of CO attainable. In general, larger furnace sizes have a greater ability to allow for greater oxidation of organics (but absent any furnace or burner constraints, fuel type, load, and load transitions also remain factors).

Obviously, increasing the size of the furnace is not an option for existing units. For these units, the strategy for reducing CO emissions is typically to raise the level of excess oxygen which, to a point, improves combustion, destroys organic HAP and minimizes CO. In this range, increasing oxygen concentration has two positive effects. First, it acts to overcome poor distribution of the fuel. Second, it increases the furnace bulk gas temperature, which speeds up the combustion reactions, allowing more complete combustion to occur for the same residence time.

However, there are also a number of negative impacts associated with operating a boiler at higher levels of excess oxygen. One is that the residence time of combustion gases in the furnace decreases, resulting in less time for complete burnout of intermediates such as CO. Many boilers do not have sufficient fan capacity to run with elevated excess oxygen at the high end of the load range. Therefore, these units would effectively be derated by such a strategy. A site might have to add another boiler to offset the reduction in steam generating capacity. If the excess oxygen is increased to very high levels, CO and hydrocarbon emissions will increase as flame stability is impaired, mainly because this leads to a cooler flame. Under these conditions boiler efficiency drops as well, so the heat value of the fuel consumed provides less value in useful process heat and neither emissions nor process economic interests are served.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 43

Comment: The minimization of excess oxygen in boiler applications is a key feature for maximizing boiler efficiency, and is therefore an appropriate operating parameter to use as an indicator of good combustion. For a given fuel, the boiler efficiency is defined by the amount of combustion air that is used, and the difference between the ambient temperature and the stack exhaust temperature. The more air that is heated up through the combustion process, the more heat is lost to the atmosphere, causing the boiler to be less efficient. A less efficient boiler will require more fuel to be fired to produce a given amount of steam. The additional fuel firing results in higher operating costs, and higher greenhouse gas emissions.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Paul Noe
Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.
Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1
Comment Excerpt Number: 44

Comment: Minimizing the level of excess oxygen is also a primary strategy for reducing NOX emissions from a boiler. The NOX formation mechanisms are dependent upon the temperatures in the flame zone, and the stoichiometry of the fuel and oxygen introduced into the furnace. Reducing the level of excess oxygen reduces the bulk gas temperature, which reduces the rate at which the nitrogen in the air dissociates. As such, there is less monatomic nitrogen available to be oxidized to form "thermal NOX". Similarly, if there is less oxygen present, the monatomic nitrogen is less likely to be oxidized (and more likely to react with a second monatomic nitrogen to form diatomic nitrogen). This reduces both the amount of thermal NOX, and the "fuel NOX" (NOX that is formed by the release of fuel-bound nitrogen). Therefore, increasing the level of excess oxygen will result in higher NOX emissions.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Dean C. DeLorey
Commenter Affiliation: The Amalgamated Sugar Company LLC (TASCO)
Document Control Number: EPA-HQ-OAR-2002-0058-3522-A1
Comment Excerpt Number: 2

Comment: For boilers with HAPs emissions above the proposed limitations, EPA has estimated the emissions control equipment at \$5.4 billion in capital expenditures³. For coal-fired units, EPA estimates a capital cost of \$4.4 million per boiler. However, the actual capital costs could be at least 2 to 3 times higher. Before a final rule is completed, sources affected by the Boiler MACT requirements need to have the opportunity to compile and submit to EPA refined projected capital cost expenditures and operational costs. Accurate cost estimates are a critical element of the Boiler MACT regulations. We request that EPA develop a questionnaire for affected sources to collect, compile and analyze this information. The proposed regulations should be delayed until the capital cost estimates are verified by EPA.

[Footnote]

(3) Section V. D. Control Costs (pg 80621)

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Dean C. DeLorey
Commenter Affiliation: The Amalgamated Sugar Company LLC (TASCO)
Document Control Number: EPA-HQ-OAR-2002-0058-3522-A1
Comment Excerpt Number: 3

Comment: The preamble lacks a detailed economic impact analysis for the increased costs required to switch boilers from coal or oil to natural gas (this may not be feasible for many boilers)⁴. Historically, natural gas costs have been approximately 3 to 4 times higher than coal costs. As a result, switching to natural gas will severely impact the profitability of most companies. The economic evaluation needs to address increased natural gas usage by all potential users including electric utilities, heating of homes and buildings and transportation sources. Please provide a detailed long-term feasibility analysis for natural gas utilization including availability and projected costs for all users including industry.

[Footnote]

(4) Section V. E. Economic Impacts (pg 80622)

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Dean C. DeLorey

Commenter Affiliation: The Amalgamated Sugar Company LLC (TASCO)

Document Control Number: EPA-HQ-OAR-2002-0058-3522-A1

Comment Excerpt Number: 8

Comment: It still remains unclear what level of add-on emissions controls are necessary to meet EPA's proposed HAPs emissions limitations. For example, when firing coal, is a fabric filter with a wet scrubber and carbon injection required to meet the proposed emissions limitations? This information is needed to verify overall control technology costs. Please provide this information in the preamble⁶.

[Footnote]

(6) Section V. D. Control Costs (pg 80621)

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Dean C. DeLorey

Commenter Affiliation: The Amalgamated Sugar Company LLC (TASCO)

Document Control Number: EPA-HQ-OAR-2002-0058-3522-A1

Comment Excerpt Number: 9

Comment: There are numerous concerns with the complex array of the monitoring, recordkeeping and reporting requirements associated with the proposed and reconsidered Boiler MACT regulations. When utilizing solids fuels Amalgamated's estimated capital costs for continuous emissions monitors (CEM's), is estimated at \$100,000 per facility. The estimated annual stack testing costs for auditing the CEM's and annual HAP's performance tests are approximately \$150,000 per facility. In addition, increased manpower will be necessary to comply with these requirements. The preamble to the proposed rule does not justify the public health benefits associated with the increased monitoring. Please provide the justification of these additional monitoring costs.

[Footnote]

(8) Section III.F. Testing & Initial Compliance Requirements (pg 80602)

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Dean C. DeLorey

Commenter Affiliation: The Amalgamated Sugar Company LLC (TASCO)

Document Control Number: EPA-HQ-OAR-2002-0058-3522-A1

Comment Excerpt Number: 14

Comment: The proposed rule will affect regulatory agencies and other entities (equipment manufacturers and environmental consultants) in varying ways. First, if affected boilers continue to choose to operate without changing fuels (e.g. coal), please document how regulatory agencies will implement these requirements including increased manpower, and government funding mechanisms (e.g. permit fees). In addition, please include the potential beneficial economic impact to equipment manufacturers and consulting companies.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Dean C. DeLorey

Commenter Affiliation: The Amalgamated Sugar Company LLC (TASCO)

Document Control Number: EPA-HQ-OAR-2002-0058-3522-A1

Comment Excerpt Number: 15

Comment: If industries choose to switch to natural gas in place of the burdensome requirements for other fuels, please document the economic impacts to regulatory agencies, equipment manufacturers and consultants. Under this scenario there will be reduced economic activity and manpower requirements (government, pollution control equipment installation and consulting) due to the less burdensome Boiler MACT requirements attributed to burning natural gas.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Dean C. DeLorey

Commenter Affiliation: The Amalgamated Sugar Company LLC (TASCO)

Document Control Number: EPA-HQ-OAR-2002-0058-3522-A1

Comment Excerpt Number: 16

Comment: Regarding the proposed Boiler MACT carbon monoxide (CO) standards, please discuss how these standards impact low NO_x burner technologies for coal-fired boilers. The very low Boiler MACT CO standards may eliminate the feasibility of low NO_x burner technology. In so, a more detailed analysis of the projected benefits of the Boiler MACT CO standards compared to NO_x reductions from low NO_x burners needs to be conducted by EPA.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Bart Sponsellar

Commenter Affiliation: Wisconsin Department of Natural Resources (DNR)

Document Control Number: EPA-HQ-OAR-2002-0058-3527-A1

Comment Excerpt Number: 1

Comment: These rules will affect a very significant number of sources which have never been subject to similar regulations. We cannot stress enough our concern in regulating so many sources for multiple pollutants for the first time. We are also very concerned that these rules will have significant and as yet unknown implications for biomass fired boilers and processes. This is very important to Wisconsin, where a significant number of our small businesses, as well as the paper industry, depend on biomass fired power. Wisconsin also feels that biomass is one vital key to growing renewable energy supplies, reducing pollutant emissions from fossil fuels, and growing our local economies.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Susan J. Miller

Commenter Affiliation: Brick Industry Association (BIA)

Document Control Number: EPA-HQ-OAR-2002-0058-3530-A1

Comment Excerpt Number: 2

Comment: EPA should not misrepresent the costs of this regulation. EPA has followed the costing assumptions and techniques in the OAQPS Control Cost Manual (EPA 452/B-02-001), which has not been updated in many years. This approach underestimates the total installed cost of air pollution control equipment, as discussed in previous comments submitted on this and various other proposed emission standards. While the EPA is not obligated to consider costs in establishing a MACT emission standard at the MACT floor level, the costs reported in the rule (and used for review by outside agencies, the public, and the Office of Management and Budget) should be accurate and based on the most up-to-date available information. Industry has provided more accurate and current costs to EPA and EPA should verify and use these costs.¹ [Footnote] (1) See Letter to EPA Docket from the American Forest and Paper Association, comments on 2010 Proposed Boiler rule (EPA-HQ-OAR-2002-0058-3213), "Evaluation of Air Pollution Control Costs for the Pulp and Paper Industry," May 1, 2003, prepared by Stone and Webster Management Consultants for National Economic Research Associates (NERA) [Appendix E] and "Cumulative Cost Burden Analysis of Air Regulations Potentially Impacting the Forest Products Industry" [Appendix C] for more current information available to EPA for estimating impacts of this rule.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 31

Comment: Most boilers are designed to mix fuel and air at an appropriate ratio, and to provide sufficient residence time for the fuel to combust completely. Obviously, these factors are fuel-dependent, as a gaseous fuel will require less time for complete combustion than a liquid fuel, which in turn requires less time to burn than a solid fuel. The need for longer residence time is why the radiant sections in solid-fuel fired boilers are larger than for gas-fired units. The size of the boiler is typically optimized to allow for complete combustion, while minimizing the cost of construction materials. If the construction cost were not a concern, a new boiler could be designed with additional residence time to complete the combustion process and minimize CO emissions.

Unfortunately, increasing the size of the furnace is not an option for existing units. For these units, the strategy for reducing CO emissions is typically to raise the level of excess oxygen. The increase in oxygen concentration has two positive effects. First, it acts to overcome poor distribution of the fuel. Second, it increases the concentration of oxygen in the gas, which speeds up the combustion reactions, allowing more complete combustion to occur for the same residence time.

However, there are a number of negative impacts associated with operating a boiler at higher levels of excess oxygen. Many boilers do not have sufficient fan capacity to run with elevated excess oxygen at the high end of the load range. Therefore, these units would not be able to operate at capacity under this strategy. A site might have to add another boiler to offset the reduction in steam generating capacity.

The minimization of excess oxygen in boiler applications is a key feature for maximizing boiler efficiency. The boiler efficiency is defined by the amount of combustion air that is present, and the difference between the ambient temperature and the stack exhaust temperature. The more air that is heated up through the combustion process, the more heat is lost to the atmosphere, causing the boiler to be less efficient. A less efficient boiler will require more fuel to be fired to produce a given amount of steam. The additional fuel firing results in higher operating costs, and higher greenhouse gas emissions.

Minimizing the level of excess oxygen is also a primary strategy for reducing NO_x emissions from a boiler. The NO_x formation mechanisms are dependent upon the temperatures in the flame zone, and the stoichiometry. Reducing the level of excess oxygen reduces the average gas temperature, which reduces the rate at which the nitrogen in the air dissociates. As such, there is less monatomic nitrogen available to be oxidized to form 'thermal NO_x'. Similarly, if there is less oxygen present, the monatomic nitrogen is less likely to be oxidized (and more likely to react with a second monatomic nitrogen to form diatomic nitrogen). This reduces both the amount of thermal NO_x, and the 'fuel NO_x' (NO_x that is formed by the release of fuel-bound nitrogen). Therefore, increasing the level of excess oxygen will result in higher NO_x emissions. Low-NO_x burner (LNB) designs for some applications manipulate the stoichiometry within the flame to minimize NO_x formation. These designs establish a fuel-rich zone for the initial phase

of combustion, and then add air at a later stage in the outer regions of the flame. In the initial phase, there is not sufficient oxygen available to form significant amounts of NO_x, and in the secondary phase, the flame is much cooler, which also inhibits NO_x formation. However, using natural gas combustion as an example, these burners often operate with CO emissions up to 10 ppmvd in the upper part of the load range. At mid loads, the CO begins to increase to near 50 ppmvd, and at low loads, it may exceed 100 ppmvd. As the EPA is continually establishing a lower ozone standard, many more facilities will likely be installing low-NO_x burners.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 74

Comment: EPA states that the presumed technology for controlling acid gases, Duct Sorbent Injection (DSI), will achieve significant control of SO₂ simultaneously to the control of HCl. EPA further states that reduction in HCl will produce a co-beneficial reduction in SO₂ of 558,400 tons per year from existing sources. This reduction is based on EPA's assumptions of an overall HCl removal efficiency of 71% and corresponding overall SO₂ reduction of 57%. EPA did not address the co-beneficial removal of SO₂ relationship in this rule, but did address the technology basis in the preamble to the Utility MACT (MATS) rule (pp. 592-602). In that discussion, EPA references multiple sources to support its application of DSI as a reasonable approach to control of HCl. Unfortunately, EPA's citations present a biased and incomplete view of the technology's efficacy for SO₂ removal.

First, EPA cites the BART analysis submitted for Dominion Energy's Kincaid Power Plant (<http://www.epa/state/il.us/air/drafts/regional-haze/bart-kincaid.pdf>). The source concludes on that DSI with Trona would achieve approximately 60% SO₂ reduction on a 30-day rolling average basis. On its surface, this would appear to support EPA's assumptions for SO₂ removal efficiency for industrial boilers. However, the SO₂ removal efficiency expected at Dominion's Kincaid Power Plant is based on the assumption that the unit will fire PRB coal with 0.3% sulfur. Because most industrial coal fired units use bituminous coals which have sulfur and chlorine contents several times higher than PRB coals, it is impossible to extrapolate any conclusions from a PRB unit to units firing bituminous coals. This BART analysis serves merely to demonstrate what one power plant with one variety of coal can achieve, but fails as a predictive tool for units firing other types of fuels.

Second, EPA cites literature published by Babcock and Wilcox, an OEM with deep experience in coal-fired power generation and the installation and retrofit of advanced emission controls. In PS-451 (<http://www.babcock.com/library/pdf/ps-451.pdf>), Babcock and Wilcox holds that Dry Sorbent Injection systems can provide "up to 80 percent SO₂ removal efficiency," which again appears to support EPA's general approach to estimating SO₂ co-benefits. However, that same document also states that in a typical DSI application, an "oversized electrostatic precipitator or new baghouse [is] required." Very few industrial units have the luxury of oversized particulate collectors, which calls into question whether a more typical unit with a correctly-sized or under-

sized particulate collector would be able to achieve high rates of SO₂ removal efficiency. In short, this paper confirms that high co-benefits are possible, but it fails to provide a predictive tool to evaluate the probability or extent of those co-benefits.

A further review of Babcock and Wilcox's published literature on DSI reveals helpful additional information correlating the technology's removal efficiency of HCl with SO₂. In BR-1851 (<http://www.babcock.com/library/pdf/BR-1851.pdf>), figure 3 shows simultaneous removal efficiencies of both HCl and SO₂ for a pilot unit configured with a pulse jet fabric filter (PJFF) firing bituminous coal. Using EPA's metric of approximately 70% HCl removal as the benchmark, a curve fitting analysis shows that the OEM's own data predicts a 30% SO₂ removal efficiency, or less than half what EPA's assumes when it calculates co-benefits.

Babcock and Wilcox also gives valuable insight into the significant variability of predicting SO₂ co-benefits in its BR-1866 (<http://www.babcock.com/library/pdf/BR-1866.pdf>). In that paper, figure 11 shows how SO₂ removal efficiency is highly dependent upon the selection of reagent. EPA rightly assumes that most sources will adopt the most cost-effective approach to controlling acid gases, which in many cases would be Trona. However, curve fitting analysis of figure 11 shows that while achieving EPA's benchmark of 57% SO₂ removal efficiency can be achieved with relatively low normalized stoichiometric ratios using Milled Sodium Bicarbonate, achieving that same level of SO₂ removal efficiency requires substantially more reagent if Milled Trona or Trona is used instead. Sources will optimize their DSI systems to control HCl, and both EPA and the OEM's acknowledge that DSI systems will preferentially treat HCl before SO₂. Thus, when a source optimizes a DSI system to satisfy the HCl requirement of this rule, it will be using significantly less reagent than required to achieve aggressive SO₂ removal efficiency. It is evident that EPA's assumptions for SO₂ co-benefits are optimistic, rather than realistic.

EPA references results published by another long-established OEM (United Conveyor Corporation) in its preamble to the Utility MACT (MATS) on page 597 (http://unitedconveyor.com/uploadedFiles/Systems/Systems_Sub/McIlvaine%20Multipollutant%20Removal%20Oct%202011.pdf). That reference shows that the SO₂ removal efficiency can vary between 30% and 70% for a HCl removal efficiency over 90% when firing eastern bituminous coal. With such a broad range of possible SO₂ removal efficiencies, it is clear that predicting a single representative value for the co-benefit is extremely challenging. EPA also describes the pilot testing of fine-milled trona at EERC's pilot facility in the preamble on page 596, stating that "fine-milled trona . . . provides 90 percent HCl removal at a SO₂ removal rate of less than 20 percent...." This comment was intended to demonstrate the selectivity of trona to target HCl rather than SO₂, but it serves to illustrate that not only is EPA's assumption of 57% SO₂ removal unrealistic, but also that EPA was aware of data that showed much smaller co-benefits than it claimed in its analysis of the benefits of the rule.

These conclusions are supported by other sources as well. Notably, Solvay Chemicals reports data substantially less optimistic than EPA's assumptions for SO₂ removal co-benefits. The slide deck by Solvay in the docket includes, on Slide 13, test data showing the simultaneous control of HCl and SO₂ compared to the total stoichiometric ratio. In this test, Solvay shows that while substantial SO₂ removal is technically achievable, approximately 35% SO₂ removal efficiency would be expected if the source controlled HCl removal efficiency to approximately 80%. In Solvay's whitepaper http://www.powermag.com/whitepapers/dry_sorbent_injection_with_trona_or_sodium_bicarbon

ate/dl/, Figure 7 predicts that when 80% HCl removal efficiency is achieved, the simultaneous SO₂ removal efficiency would be between 10% and 25%. All of these results cast doubt on the amount of credit EPA takes in its analysis of co-benefits.

Taken together, the balance of published knowledge strongly indicates that EPA's assumptions when calculating co-benefits due to SO₂ removal is grossly optimistic [see submittal for table].

CIBO agrees that some SO₂ removal co-benefit will occur with DSI systems installed to control HCl. However, experience shows that the amount of co-benefit will depend on the type of fuel being fired (e.g. bituminous, PRB, oil, etc.), the concentration of chlorine and sulfur in a given units particular fuel, the reagent selected (trona, milled trona, sodium bicarbonate, etc.), the temperature and residence time available for the reagent to react with the HCl and SO₂, and the particulate collector type and size. These variables mean the actual co-benefit will be highly site specific. Based on a review of published results (summarized in the table above) [see submittal for table], it is clear that EPA has overstated the co-beneficial removal of SO₂ by at least a factor of two, and perhaps as much as a factor of five or six.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A4

Comment Excerpt Number: 1

Comment: URS Corporation (URS) worked with the Council of Industrial Boiler Owners (CIBO) and its members to develop a rough order of magnitude estimate of the initial capital cost of complying with the Industrial Boiler MACT. The cost estimates were compiled in a Microsoft Excel workbook; were based on published information or similar project costs; have been reviewed by member company representatives; and have been made available to the US EPA and others for review. The Boiler MACT estimated costs are in large part based on information in EPA's December 2011 survey and emissions databases. Capital and operating costs estimates are not intended to represent a worst case analysis. Rather, they represent median costs for the various scenarios based on published reports, industry information on specific project costs, EPA reports or control device fact sheets, or actual BACT or BART analyses submitted to permitting agencies. A primary resource was the document "Evaluation of Air Pollution Control Costs for the Pulp and Paper Industry," prepared by National Economic Research Associates (NERA) in May 2003. All costs were discussed with a core team of CIBO members and reviewed by URS engineers familiar with boiler operations and controls prior to finalizing the study.

The Boiler MACT will require emissions controls for particulate matter, hydrogen chloride, mercury, and carbon monoxide. The control technologies that EPA has identified as necessary to comply with the Boiler MACT are a fabric filter for control of particulate matter, carbon injection for control of mercury, a scrubber for control of hydrogen chloride, and combustion improvements or an oxidation catalyst for control of carbon monoxide. Although in some cases, the emission limits will be very difficult to achieve over all operating conditions, our cost analysis assumes that for each boiler, we can apply emissions controls to achieve the Boiler

MACT limits with a comfortable margin of compliance. In some cases, existing equipment configurations may prove impossible to upgrade, and boilers and process heaters may need to be replaced, which is a cost that is not reflected in our analysis. Note also that many facilities may choose fuel switching as a compliance option; however, as the cost of fuel switching is highly dependent on site specific factors (e.g., whether the boiler can burn the alternate fuel, what upgrades must be made to the fuel supply system) and the price of fuel will change over time due to factors like supply and demand, we did not attempt to quantify costs for fuel switching. The EPA collected information during Phase 1 of the Boiler MACT information collection request (ICR) on thousands of boilers and process heaters at hundreds of facilities. A detailed spreadsheet was developed to estimate costs for Boiler MACT for individual boilers and process heaters, based on EPA's major source boiler inventory database table and the emissions data included in EPA's boiler MACT database. URS extracted information from EPA's major source boiler inventory database including boiler ID, size, fuel category, emissions, and current air pollution control equipment. Based on the information in EPA's database and the baseline emission factors developed by EPA by boiler fuel, design, and control device, URS determined whether each unit would require additional air pollution controls to meet the Boiler MACT limits. Note that we did not perform any quality assurance on the information in EPA's database, but where we had knowledge that a boiler had been mis-categorized (e.g., a biomass boiler was listed as a liquid boiler) we did make those changes in our spreadsheet. A spreadsheet was developed that represents only the units that will have numeric emission limits (excludes natural gas boilers and process heaters, boilers and process heaters less than 10 MMBtu/hr heat input, and limited use units). Based on the information in the EPA emissions database and other docketed EPA cost memos, we estimated costs of controls that would likely be necessary to comply with the Boiler MACT for coal, biomass, liquid, and Gas 2 boilers 10 MMBtu/hr and greater (note that EPA has moved all process gas-fired boilers to the Gas 1 subcategory unless they were burning any amount of coke oven gas). Information from various sources was used to determine a base capital cost for a 250 MMBtu/hr boiler for each PM, CO, and HCl control technology option and then scaled using an 0.6 power function based on the size of each boiler in the inventory. For example, the capital cost of a wet scrubber on a 100 MMBtu/hr boiler is calculated as the base cost times $(100/250)^{0.6}$. A fixed cost of \$1 million was assumed for installation of a carbon adsorption system for Hg control, as these systems do not vary much in cost by boiler size. Base cost assumptions are presented below.

[See submittal for Table]

Controls were evaluated separately, first for particulate matter, then for hydrogen chloride, then for mercury, and last for carbon monoxide. To estimate Boiler MACT controls and costs for each unit, if there was no emissions information available for a particular boiler, we use the baseline emission factors developed by EPA for their analysis. In their boiler inventory table, EPA put the boiler pollution controls into categories. The categories are explained in greater detail in EPA's baseline emission factor memo, but basically are as follows: for the PM control code, 1=FF, 2=EFB/ESP, 3=venturi scrubber, 4=wet scrubber, 5=multiclone, 6=none/mist eliminator/unknown. If a unit did not already have a FF or ESP and there was information that indicated the unit cannot meet the limit, we assumed a new FF. If the unit already had a FF or ESP and there was information that indicated the unit cannot meet the limit we assumed an upgrade to the existing control equipment. For the HCl control code, 1=wet scrubber or spray dryer, 2=dry scrubber, 3=sorbent injection, 4=venturi scrubber, 5=none/dry PM only. To

estimate control costs for HCl, if there was information that indicated the unit cannot meet the limit, we assumed no additional capital cost for codes 1-3 (there would be an increase in sorbent injection but no additional capital), a scrubber upgrade for code 4 (venturi scrubber), and a new scrubber for code 5 (no scrubber). For the Hg control code, 1=carbon injection, 2=FF plus sorbent injection or spray dryer, 3=FF only, 4=wet scrubber, 5=venturi scrubber, 6=none/multiclone/EFB/mist eliminator. For Hg, if there was information that indicated the unit cannot meet the limit, we added carbon injection. For CO, if there was stack test information that indicated the unit cannot meet the CO stack test-based limit, then we assumed that capital would be necessary to either perform combustion/fuel feed improvements or other boiler improvement projects to reduce CO or install a CO catalyst. Although EPA's estimates indicate that the total capital cost of the final rule will be \$5.4 billion, CIBO has estimated that the total capital cost of the rule will be \$14.3 billion for industry. It is evident major capital investments in add-on control technology will be required for continued operation of solid and liquid fueled boilers and process heaters.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A4

Comment Excerpt Number: 2

Comment: Our capital cost estimates differ from EPA's cost estimates as follows:

- EPA has used the outdated Control Cost Manual and we have based our cost estimates on more recent information, including actual vendor cost estimates, actual project costs, BACT and BART analyses, industry control cost studies, etc.

We used a CO catalyst cost higher than EPA's. Ours is based on a recent quote from BASF and EPA's is based on the 1998 Control Cost Manual section on catalytic oxidizers for VOC control.

EPA has estimated that a tune-up or burner replacement will be adequate for many units to achieve the CO limits. We do not agree with this assumption because some of the CO limits are fairly low and must be met over all operating conditions except startup and shutdown, so we have estimated higher costs to implement combustion controls, burner replacements, fuel feed system improvements, or CO catalyst.

Our CO control capital costs are higher than EPA's, mostly because EPA assumed that tune-ups and replacement burners will be adequate for the vast majority of boilers to comply, and we disagree with that assumption. EPA has estimated that activated carbon injection will be required on only 35 existing units because installation of a fabric filter is expected to achieve the mercury emission limits, except in cases where a unit already has a fabric filter and does not meet the limits. We do not agree that fabric filters will be sufficient to reduce mercury emissions to the some of the ultra-low levels in this rule. There is a flaw in the logic that fabric filters are expected to achieve mercury emission limits when there are many boilers in the database that are equipped with fabric filters and have measured mercury emissions higher than the applicable

limit. EPA's estimated industry-wide capital cost for activated carbon injection presented in the ERG cost and emissions impacts memo is extremely low, at only \$115,000 per unit.

EPA has estimated costs to install packed bed scrubbers for HCl control. Industrial boilers do not use packed bed scrubbers for acid gas control, as the limitations of these devices make them impractical for use on applications with high flow rates, high PM loading, and high inlet pollutant concentration. EPA's own fact sheet on these devices, located at <http://www.epa.gov/ttn/catc/dir1/fpack.pdf>, lists these limitations of these devices and indicates that they are only used in applications up to 75,000 scfm, which limits their use to small units only (EPA responded to this comment by applying multiple packed bed scrubbers to units with higher flow rates). Facilities will instead install wet scrubbers, dry scrubbers, or semi-dry scrubbers to control acid gas emissions from industrial boilers. EPA has estimated HCl control costs for equipment that industry is not likely to install. The following capital costs for control additions/upgrades were estimated by URS/CIBO for coal, biomass, liquid, and gas 2 units having numerical emission limits under Boiler MACT: [See submittal for Table]

EPA has estimated a control cost of only \$5.4 Billion for the rule. Note that the initial cost estimate increases to \$14.5 billion for coal, biomass, liquid, and gas 2 units when the costs of testing, monitoring, tune-ups, and energy assessments are factored in.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Kristin Palecek

Commenter Affiliation: Flambeau River Papers

Document Control Number: EPA-HQ-OAR-2002-0058-3541-A1

Comment Excerpt Number: 2

Comment: A concern is the impact this rule will have on new projects. Since the company I work for has been contemplating a biofuels project, our experience with the rule can give a new project perspective. The Boiler MACT rule put a major wrench into our planning process when exorbitant pollution control costs required us to switch from an advanced, state of the art drying process to the old, regular type. Is this what we want our rules to do? Don't we want our rules to encourage new technology? The return on the project was lost when we looked at how much pollution control technology would be required. Having to put two wet electrostatic precipitators in series to ensure that the limit was met was enough to take away the return on the project.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Kristin Palecek

Commenter Affiliation: Flambeau River Papers

Document Control Number: EPA-HQ-OAR-2002-0058-3541-A1

Comment Excerpt Number: 3

Comment: One of my other main concerns with Boiler MACT is that it pushes companies towards firing their boilers with natural gas. This is very short term thinking for several reasons.

While that decision might be easy to make now while natural gas prices are low, as recent as 2008 the US was experiencing high natural gas costs. How many companies will be able to afford the 5x swing in natural gas pricing when that happens the next time around? Companies need to have flexibility so they can have long term survival. One of the main reasons our mill closed for several months in 2006 was because of the high natural gas costs. Another reason that this is short-term thinking is because of the fossil fuel impact of natural gas. How can we say that long-term we want to reduce fossil fuel emissions yet Boiler MACT will push most businesses towards natural gas?

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Kristin Palecek

Commenter Affiliation: Flambeau River Papers

Document Control Number: EPA-HQ-OAR-2002-0058-3541-A1

Comment Excerpt Number: 4

Comment: If the Clean Air Act requires that the top 12% of boilers be used to set the new limits then why are the estimates showing that approximately 94% of boilers impacted by the rule will be requiring major capital investments? Something is not adding up. The mill that I work at can't afford the \$5 million initial and \$1.5 million additional annual costs. With an annual economic impact of \$300 million to the state economy and an \$18 million federal and state tax loss the sting of our little mill closing will be felt throughout the state. Other mills that are looking at similar investments will add to many more manufacturing jobs being lost because of this rule. With the present state of the economy this is not the time to be adding costly rules.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Kristin Palecek

Commenter Affiliation: Flambeau River Papers

Document Control Number: EPA-HQ-OAR-2002-0058-3541-A1

Comment Excerpt Number: 5

Comment: It boggles my mind why we would want to force ourselves to take on some of the strictest limits internationally. How are we supposed to compete with foreign markets? Although there are a few countries that appear to have similar limits, they are allowed more flexibility with their regulators versus what is seen in the United States. While US companies will be pouring billions into pollution control equipment other countries will be able to make a return on their investments. A cost benefit analysis must be accurately measured before this rule is finalized. It is disconcerting to see groups such as AFPA say that the costs associated with this rule have been underestimated by almost 3 fold.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Bruce A. Steiner

Commenter Affiliation: American Coke and Coal Chemical Institute (ACCCI)

Document Control Number: EPA-HQ-OAR-2002-0058-3547-A2

Comment Excerpt Number: 5

Comment: As we noted in our August 23, 2010 comments on the originally proposed Boiler MACT, if EPA finalizes a rule that subjects coke oven gas-fired boilers to the stringent numeric emissions limitations proposed for Gas 2 sources, the additional cost of controls would functionally eliminate valuable efforts to reclaim energy. The U.S. Department of Energy has awarded competitive grant funds to energy recovery projects that convert flared coke oven gas to usable steam and electricity. The rule's requirements would discourage the type of energy recovery project that DOE is actively trying to promote. This is because the annualized cost of control required to meet the Gas 2 emission limits exceeds the cost of replacement natural gas for many units. Facing this economic reality, coke oven gas will be flared and natural gas will be combusted to generate steam to the detriment of the environment and our national goals of energy independence. The economic analysis is clear. Gas 2 requirements establish numeric emission limits for multiple pollutants. At this time, coke oven gas-fired units are not controlled for these compounds. Using EPA's projected cost of control (annualized capital cost plus annual operating cost) for each pollutant, including monitoring, recordkeeping and reporting, an ACCCI member company has calculated an annualized cost of control of \$8.6 million for a single 650 MMBTU/hr boiler combusting coke oven gas.²⁶ At a cost of \$5/MMBTU for natural gas, it is economically unreasonable for the boiler operator to use coke oven gas to displace the first 1,720,000 MMBTU per year of natural gas in this boiler and the coke oven gas would be flared. The use of natural gas to replace coke oven gas in this situation would be to the detriment of the environment and our energy policies. The constraint on available capital is an additional impediment to the installation of emission control equipment because increased natural gas consumption does not require a capital investment. Before a company will invest \$8.6 million in annualized control costs for a single boiler, it will need to justify a return on the capital investment far greater than \$8.6 million per year in displaced natural gas. Moreover, as discussed below, there is no expectation that expenditures of this magnitude will be sufficient to meet the proposed Gas 2 subcategory emission limits.

[Footnote]

(26) The capital cost for the unit is \$27,747,000 and the annual non-capital cost is \$5,678,000.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Frank H. Thorn

Commenter Affiliation: Newport News Shipbuilding

Document Control Number: EPA-HQ-OAR-2002-0058-3548-A2

Comment Excerpt Number: 14

Comment: Installation of add-on emission controls on the NNS Floating Test Steam Facility (FTSF) marine boilers is infeasible and not cost-effective. The FTSF marine boilers currently do not meet all of the Boiler MACT emission limitations identified in the table above. Based on

NNS' evaluation of its FTSF marine boilers and demonstrated air pollution control technologies, NNS has identified the following add-on control technologies as apparently most applicable to controlling the FTSF marine boiler emissions to the levels required by the Boiler MACT:

- Fabric Filter (baghouse) w/Dry sorbent injection
- Fabric Filter (baghouse) w/Activated carbon injection
- Wet or Dry Electrostatic Precipitator (ESP)
- Wet Scrubber (Packed Bed)
- Flue Gas Desulfurization (FGD)

These identified technologies are consistent with those considered by EPA in its Regulatory Impact Analysis (EPA-HQ-OAR-2002-0058-3290). However, a conventional land-based air pollution control system employing any of these technologies would not be a viable option for the FTSF marine boilers at NNS, because the FTSF barge must operate at more than one distinct waterfront location, depending on ship locations during overhaul, thus requiring redundant emission control systems. In addition, unique and unproven methods would also be required to be successfully designed and constructed in order to capture the stack exhaust gases from both of the FTSF marine boilers while the barge rises and falls with the tide, or moves slightly with the wind and currents, or when the barge must be moored at slightly different locations alongside the NNS piers depending on the particular aircraft carrier being serviced and the location of a particular ship's interconnecting steam piping. Furthermore, the cost of redundant landbased emission control systems to accommodate a portable emission source such as the FTSF barge would multiply the actual emission control cost in real dollars, as well as on a "dollars per ton of pollutant removed" basis, to a level far above EPA's own estimates of Boiler MACT compliance costs.

To address the concerns associated with movement of the FTSF barge relative to an air emission control system located on fixed land, NNS considered the possibility of designing and constructing a separate barge-mounted emission control system which could be placed alongside the FTSF barge and lashed to it at any of its possible waterfront operating locations. Such an arrangement presents the difficult problem of safely placing and maintaining large-diameter interconnecting ductwork between the two barges using a crane, and also precludes bringing the fuel oil delivery barge alongside the FTSF when delivering fuel. Furthermore, the two barges themselves will move slightly with respect to each other, thus not fully resolving the movement concern. Lastly, the cost of designing and constructing a floating emission control system compact enough to fit on a barge is considerably higher than the cost of an equivalent land-based system, again exceeding EPA's own estimates of Boiler MACT compliance costs. NNS also considered the possibility of installing add-on emission control equipment on the FTSF barge itself. The two FTSF marine boilers comprise nearly the entire breadth and width of the FTSF barge. Exhibit 1 shows a photograph of the FTSF barge while undergoing routine maintenance in dry dock between successive carrier steaming activities. Exhibit 2 shows an overhead view of the FTSF barge while moored adjacent to an aircraft carrier in preparation for steaming the carrier. Exhibit 4 shows several photographs of the working spaces surrounding the boilers on the FTSF barge. It can be seen from these photographs that no significant additional space is available on the barge to construct or install any of the identified emission control technologies considered to be applicable to the FTSF emissions. [See submittal for Exhibits 1, 2, and 4.] NNS considered

the possibility of erecting a superstructure on the FTFSF barge and placing the add-on control equipment above the boilers' exhaust stacks. The weight of the add-on control equipment is estimated to be 140,000 to 200,000 pounds. The barge would require a rigorous naval architectural review if it were to be burdened with this additional weight of emission control equipment, especially considering that the weight of the added equipment could significantly affect the center of gravity and also would likely not be evenly distributed across the barge. In fact, listing of the barge (leaning to one side) when fuel oil is loaded and as it is consumed during operation commonly occurs and must be carefully controlled by monitoring the barge's list and trim and by using the fuel oil itself as ballast by pumping the oil through a network of tanks and piping below deck. The FTFSF barge was specifically designed by NNS naval architecture personnel to accommodate the weight of the two boilers as well as over 500,000 gallons of fuel oil stored in tanks below deck. NNS believes that significant additional weight cannot be accommodated without extensive, costly structural modifications to the barge. Furthermore the suitability of existing emissions control equipment for the unique FTFSF has not been demonstrated. EPA has not considered or included in its economic analysis the additional cost of constructing and operating portable emission control systems for portable emission sources like the FTFSF, nor has it considered the cost of redundant emission control systems that would be required for portable emission sources such as the FTFSF. This is not surprising, since the FTFSF is a unique facility, as described earlier. Based on EPA's Regulatory Impact Analysis, EPA's estimated average capital cost for add-on controls for liquid-fired boilers is approximately \$3.7 million per boiler (derived from Table 3.1 of the analysis). The need for NNS to employ redundant land-based air pollution control systems or, more likely, a bargemounted system to meet the Boiler MACT emission limitations for its FTFSF marine boilers, drives the capital cost of emission controls for FTFSF boilers up two to three times that of regulated industrial boilers of equivalent size. Furthermore, NNS believes that at least four years would be required to conduct the unique and complex engineering required to design a suitable emission control system for the FTFSF marine boilers, construct the system, and evaluate and troubleshoot its performance to ensure its reliability and effectiveness. The Boiler MACT as promulgated only allows three years from the effective date to come into compliance, which is not sufficient. While §112(i)(3)(B) of the Clean Air Act allows EPA or a state the authority to issue a permit that grants an extension allowing an existing source up to one additional year to comply with the Boiler MACT, if such additional period is necessary for the installation of controls, NNS cannot assume that it would be granted such an extension and cannot rely on an extension as its Boiler MACT compliance plan. Further, the unique nature of the FTFSF as well as the difficulty of designing engineering solutions for the installation of pollution control equipment under these conditions mean that NNS cannot be certain that initial designs will be workable. Therefore, NNS does not believe it to be reasonable that this option could be accomplished by the Boiler MACT compliance date (which is currently March 21, 2014), even if slightly delayed pursuant to EPA's delay of the Boiler MACT effective date

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Annabeth Reitter
Commenter Affiliation: NewPage Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3662-A2

Comment Excerpt Number: 7

Comment: The proposed Boiler MACT reconsideration rule has the potential to still be very costly for NewPage.

We have conducted limited engineering review to estimate the compliance costs for the proposed reconsideration rule. The re-subcategorization and more stringent emission standards results in preliminary estimates of compliance costs significantly higher than the March 2011 final rule. These preliminary engineering estimates indicate extraordinary capital expenditures and several million dollars in additional annual operating costs. These costs are significant and will put NewPage at a distinct disadvantage as we compete in a global marketplace with other paper producers located in jurisdictions that do not have to comply with these requirements. In order to remain cost competitive with foreign competition, we cannot pass-on these substantial compliance costs. Due to significant economic pressure and a struggling economy, NewPage has had to close several of our manufacturing facilities and eliminate hundreds of high paying jobs. The compliance cost estimates for the proposed Boiler MACT reconsideration rule indicates that U.S. manufacturing will need to spend billions of dollars to fund compliance requirements. With a still struggling economy, additional manufacturing facilities may close and jobs will be shed. With the large financial burden for compliance, additional mill closures may be the final fate for some of our facilities unless changes to the proposed reconsideration rule are made to significantly lessen the impact.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Annabeth Reitter

Commenter Affiliation: NewPage Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3662-A2

Comment Excerpt Number: 8

Comment: As a result of additional sub-categorization for solid fuel units, many of the emission standards became more stringent. As noted above, for the NewPage these more stringent standards for PM, HCL, mercury and CO will result in higher compliance costs.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Douglas Emerson et al.

Commenter Affiliation: American Crystal Sugar Company et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3675-A2

Comment Excerpt Number: 1

Comment: As potential regulated entities, American Crystal Sugar Company and Michigan Sugar Company request that the Environmental Protection Agency carefully consider the following comments to the proposed rule making. The proposed rule, as written, has the potential to greatly impact operations at not only our facilities, but at every one of the twenty-two sugar

beet processing facilities located throughout the United States, which will result in significant costs both for initial compliance as well as ongoing compliance. Existing operations will require significant physical modification at many facilities in order to comply with the proposed rule requirements. Initial compliance studies performed for American Crystal Sugar facilities indicate initial compliance costs in the range of \$10 million to \$20 million for each of the existing facilities. This excludes the additional cost of ongoing annual compliance, which as yet has not been quantified.

Physical modifications required to comply with the proposed rule may also have the secondary impact of triggering additional rule requirements, such as New Source Performance Standards and Prevention of Significant Deterioration Regulations. These secondary compliance requirements have the potential for additional major capital investment. Furthermore, future operations of affected sources may be seriously jeopardized due to constraints imposed on fuel flexibility and future availability of fuels.

In addition to compliance requirements of the proposed rule, significant costs will, and have been, incurred in advance of rule applicability dates to determine compliance options and strategy. This is evidenced by the fact that American Crystal Sugar Company has already made investments exceeding several hundred thousand dollars to develop compliance options and strategy prior to the finalization of rulemaking activities. This investment is necessary for companies with multiple potentially affected sources due to the significance of required modifications as well as the short time frame for compliance allowed under the proposed rule.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 3

Comment: EPA's analysis shows that, despite high costs, there are essentially no emission or health benefits from the imposition of the proposed requirements for gas-fired units. While the costs imposed on BPH that fire natural gas, refinery gas and other gas 11 is certainly less than the costs that would have been incurred from imposing numerical emission limitations, the costs and burdens imposed by the work practice requirements, particularly the energy assessment work practice, are still very substantial and are not justified. Not only are there little or no benefits from HAP reductions from gas fired BPH, there are also little or no PM benefits. EPA estimates that there will be just 132 tons per year of potential PM emissions reduction from gas-fired BPH reduced nationally, compared to their estimate of 42,695 Tons per year total reduction from major source BPH 2 . EPA didn't provide the estimated amount of organic HAP reduced for gas-fired units in Table 4 of the proposal preamble, but EPA estimated that the total VOC reduction is only 246 tons from gas-fired units and organic HAP certainly will be a small part of the VOC reduction.

The perspective of the petroleum industry on the BPH NESHAP proposal is that it imposes enormous costs and potentially jobs reductions without any substantial emission or health benefits from the industry sectors in which we operate. For gas-fired equipment, EPA's docketed data shows that there are no health benefits or other benefits associated with regulating these sources. Gas is the primary fuel of the petroleum industry. Our industry is unquestionably already economically incentivized to maintain a high level of energy efficiency. To recapitulate, EPA should document in their analysis - to inform their decision making process - that for gas fired equipment there are no benefits associated with new standards and that any standard will only impose additional costs.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Kerry Kelly

Commenter Affiliation: Waste Management (WM)

Document Control Number: EPA-HQ-OAR-2002-0058-3681-A2

Comment Excerpt Number: 9

Comment: Should boiler owners switch fuel from LFG to one of the currently defined Gas 1 fuels, increased pollution emissions will occur. Use of natural gas or refinery gas will increase criteria pollutant and greenhouse gas emissions compared to LFG. LFG has been shown to produce lower nitrous oxide emissions than natural gas, and using LFG lowers fossil carbon dioxide emissions as compared to both Gas 1 fuels.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Richard D. Garber

Commenter Affiliation: Boise Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3686-A2

Comment Excerpt Number: 7

Comment: During the past several years and recent economic downturn, Boise was forced to close a pulp mill and two uncoated freesheet paper machines and indefinitely curtail operation of a newsprint machine resulting in about 430 direct jobs lost or about 8% of our workforce. Further economic pressures are expected due to fierce competition from overseas manufacturers as well as an onslaught of regulatory activity. Therefore, it is imperative that mandatory environmental controls such as the Boiler MACT standard be designed such that human health and the environment are protected without requiring unnecessary expenditures of time and resources.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Heather Parent

Commenter Affiliation: Maine Department of Environmental Protection

Document Control Number: EPA-HQ-OAR-2002-0058-3691-A2

Comment Excerpt Number: 18

Comment: Maine DEP is concerned that efforts to minimize CO emissions to comply with the rule will have the effect of causing increases in nitrogen oxide (NOx) emissions. Maine DEP has focused much attention on reducing NOx emissions from these same units, through the use of good combustion practices or add-on control technology to reduce ground level ozone levels. We do not want to see these efforts undermined due to the inverse relationship between CO and NOx emissions, particularly where no add-on control equipment is utilized to control NOx emissions from these units.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Dell Majure

Commenter Affiliation: Kimberly-Clark Corp.

Document Control Number: EPA-HQ-OAR-2002-0058-3692-A2

Comment Excerpt Number: 4

Comment: A CO catalyst could be installed upstream of the particulate emission control device where the flue gas temperature is above the minimum effective temperature (600 °F) where the catalyst becomes effective. This installation location is not feasible because of the high amount of particulate in the flue gas stream that would rapidly foul the CO catalyst rendering it ineffective. The same CO catalyst could be installed downstream of the final particulate emission control device to minimize fouling however the flue gas stream temperature would be well below the required 600 °F. It is feasible that the flue gas stream could be reheated with a natural gas burner to allow the CO catalyst to be effective but the trade-off is an increase in the emission rate of NOx. An increase in the emission rate of NOx may be prohibited by new source review especially in a non-attainment area. NOx may be able to be controlled by installing selective non-catalytic NOx reduction (SNCR) in the furnace section but additional study is required to determine its feasibility with a flue gas particulate content that is significantly higher than a unit firing bituminous coal for example.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Commenter Name: Regina Hopper

Commenter Affiliation: America's Natural Gas Alliance (ANGA)

Document Control Number: EPA-HQ-OAR-2002-0058-3444-A1

Comment Excerpt Number: 4

Comment: ANGA requests that EPA revise its unsupported conclusion that fuel switching to natural gas would lead to an increase in HAP emissions. For a further discussion of this issue, see pages 5-7 of ANGA's August 23, 2011 comments. EPA correctly concludes that natural gas is the "cleanest fuel available for boilers" in the rulemaking. We encourage the agency to make its control decisions based on the scientifically supported fact that natural gas is a clean burning fuel.

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.

Executive Orders

16A. Executive Order 12866, Regulatory Planning and Review

Commenter Name: Robert E. Hunzinger

Commenter Affiliation: Gainesville Regional Utilities (GRU), Florida

Document Control Number: EPA-HQ-OAR-2002-0058-3488-A1

Comment Excerpt Number: 7

Comment: GRU has concerns that EPA's estimate for the direct monetized health benefits of the final and reconsideration rule are significantly lower than the direct costs. EPA's economic analysis actually depends on co-benefits related to PM_{2.5} reductions to produce benefits for the rule that exceed the costs. Based on the stringency of the Major Source NESHAPS, GRU believes that the direct benefits of the rule should exceed the costs. In addition, since the National Ambient Air Quality Standard (NAAQS) for PM_{2.5} has been established at a level to protect human health and welfare with a margin of safety, there appears to be some question as to the quantification of the co-benefits for this rule.

Response: The EPA disagrees with this commenter that co-benefits should be excluded in the estimation of benefits expected by this regulation. The EPA has determined that the proposed rule will lead to reductions of criteria and HAP responsible for significant adverse health effects and that such reductions will produce substantial public health benefits. Accounting for ancillary impacts is standard practice in benefit-cost assessment since these benefits are a consequence of the rule, regardless of the rule's intended purpose. The EPA estimates all of the anticipated costs and benefits associated with a regulatory action, to the extent feasible, for the purpose of determining the likely impacts, not to justify an action. This rule is expected to achieve substantial PM_{2.5} health benefits resulting from primary PM and SO₂ emission reductions, and these co-benefits have been included in the regulatory impact assessment.

Consideration of ancillary benefits in benefit-cost analysis is directed by OMB Circular A-4 (2003) (p. 26, available at: http://www.whitehouse.gov/omb/circulars_a004_a-4/): “Your analysis should look beyond the direct benefits and direct costs of your rulemaking and consider any important ancillary benefits and countervailing risks. An ancillary benefit is a favorable impact of the rule that is typically unrelated or secondary to the statutory purpose of the rulemaking (e.g., reduced refinery emissions due to more stringent fuel economy standards for light trucks) while a countervailing risk is an adverse economic, health, safety, or environmental consequence that occurs due to a rule and is not already accounted for in the direct cost of the rule (e.g., adverse safety impacts from more stringent fuel-economy standards for light trucks).”

It is also directed by the EPA's *Guidelines for Preparation of Economic Analyses* (2010) (p. 11-2, available at:

<http://yosemite.epa.gov/ee/epa/eed.nsf/pages/Guidelines.html>): “An economic analysis of regulatory or policy options should present all identifiable costs and benefits that are incremental

to the regulation or policy under consideration. These should include directly intended effects and associated costs, as well as ancillary (or co-) benefits and costs.”

In line with this guidance, the EPA estimates all of the anticipated costs and benefits associated with a regulatory action, to the extent feasible. We further note that we were unable to monetize other important benefits, including health benefits of ozone reductions, additional PM_{2.5} health benefits, and direct health benefits of reducing SO₂. If we were able to fully monetize these benefits, the benefits would exceed the costs by an even greater amount than we currently estimate.

The EPA also notes that while the PM co-benefits are appropriately included in the benefit-cost analysis accompanying the rule, the benefit-cost analysis is not the justification for the rule. The rule is justified based on the requirements of the CAA, which requires EPA to issue standards to reduce HAPs for listed source categories.

The EPA disagrees that the existence of a NAAQS for PM_{2.5} somehow undermines the benefits estimated for this rule. The PM_{2.5} health benefits anticipated from this rule are based on the best available peer-reviewed science and methods that have withstood scrutiny from EPA’s independent Science Advisory Board, the National Academy of Sciences, and continuous interagency review. These benefits are not double-counted with benefits estimated in other RIAs. The NAAQS RIAs illustrate the potential costs and benefits of attaining a new air quality standard nationwide based on an array of emission control strategies for different sources. In short, NAAQS RIAs hypothesize, but do not predict, the control strategies that states may choose to enact when implementing a NAAQS. The setting of a NAAQS does not directly result in costs or benefits, and as such, the NAAQS RIAs are merely illustrative and are not intended to be added to the costs and benefits of other regulations that result in specific costs of control and emission reductions. In implementing these rules, emission controls may lead to reductions in ambient PM_{2.5} below the PM NAAQS in some areas. Although benefits occurring below the standard may be less certain than those occurring above the standard, the EPA considers them to be legitimate components of the total benefits estimate.

Commenter Name: Randal G. Oswald

Commenter Affiliation: Integrys Energy Group

Document Control Number: EPA-HQ-OAR-2002-0058-3659-A2

Comment Excerpt Number: 14

Comment: Integrys requests that EPA reevaluate the monetized health benefits of the Major Source Rule and the Proposal without accounting for co-benefits from reductions in fine PM. We are concerned that the monetized health benefits *directly* associated with the rule do not exceed the actual costs of the rule. EPA should accurately identify the direct costs of regulation as compared to the benefits expected.

Response: The EPA disagrees with this commenter that co-benefits should be excluded in the estimation of benefits expected by this regulation. The EPA has determined that the proposed rule will lead to reductions of criteria and HAP responsible for significant adverse health effects and that such reductions will produce substantial public health benefits. Accounting for ancillary impacts is standard practice in benefit-cost assessment since these benefits are a consequence of

the rule, regardless of the rule's intended purpose. The EPA estimates all of the anticipated costs and benefits associated with a regulatory action, to the extent feasible, for the purpose of determining the likely impacts, not to justify an action. This rule is expected to achieve substantial PM_{2.5} health benefits resulting from primary PM and SO₂ emission reductions, and these co-benefits have been included in the regulatory impact assessment.

Consideration of ancillary benefits in benefit-cost analysis is directed by OMB Circular A-4 (2003) (p. 26, available at: http://www.whitehouse.gov/omb/circulars_a004_a-4/): “Your analysis should look beyond the direct benefits and direct costs of your rulemaking and consider any important ancillary benefits and countervailing risks. An ancillary benefit is a favorable impact of the rule that is typically unrelated or secondary to the statutory purpose of the rulemaking (e.g., reduced refinery emissions due to more stringent fuel economy standards for light trucks) while a countervailing risk is an adverse economic, health, safety, or environmental consequence that occurs due to a rule and is not already accounted for in the direct cost of the rule (e.g., adverse safety impacts from more stringent fuel-economy standards for light trucks).”

It is also directed by the EPA's *Guidelines for Preparation of Economic Analyses* (2010) (p. 11-2, available at: <http://yosemite.epa.gov/ee/epa/eed.nsf/pages/Guidelines.html>): “An economic analysis of regulatory or policy options should present all identifiable costs and benefits that are incremental to the regulation or policy under consideration. These should include directly intended effects and associated costs, as well as ancillary (or co-) benefits and costs.”

In line with this guidance, the EPA estimates all of the anticipated costs and benefits associated with a regulatory action, to the extent feasible. We further note that we were unable to monetize other important benefits, including health benefits of ozone reductions, additional PM_{2.5} health benefits, and direct health benefits of reducing SO₂. If we were able to fully monetize these benefits, the benefits would exceed the costs by an even greater amount than we currently estimate.

The EPA also notes that while the PM co-benefits are appropriately included in the benefit-cost analysis accompanying the rule, the benefit-cost analysis is not the justification for the rule. The rule is justified based on the requirements of the CAA, which requires EPA to issue standards to reduce HAPs for listed source categories.

Commenter Name: Allison Watkins, Baker Botts
Commenter Affiliation: Class of '85 Regulatory Response Group
Document Control Number: EPA-HQ-OAR-2002-0058-3608-A1
Comment Excerpt Number: 15

Comment: The Class of '85 requests that EPA reevaluate the monetized health benefits of the Major Source Rule and the Proposal without accounting for co-benefits from reductions in fine PM. The Group is concerned that the monetized health benefits *directly* associated with the rule do not exceed the actual costs of the rule. EPA should accurately identify the direct costs of regulation as compared to the benefits expected.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3659-A2, excerpt 14.

Commenter Name: Dean C. DeLorey

Commenter Affiliation: The Amalgamated Sugar Company LLC (TASCO)

Document Control Number: EPA-HQ-OAR-2002-0058-3522-A1

Comment Excerpt Number: 1

Comment: The preamble of the proposed rule and reconsideration continues to inappropriately document the overall air quality benefits associated with the proposed boiler MACT emissions limitations¹. The preamble needs to include an analysis of the percentage decrease in annual HAPs emissions relative to all HAPs emissions sources. Because of the staggering costs to industries and small businesses associated with this rule, it is critical that the net air quality benefits are considered when establishing the Boiler MACT HAPs limits. Please revise the preamble to include this important documentation.

The preamble does not appropriately document cost savings associated with the rule². The preamble to the reconsidered rules suggests that there will be \$27 billion to \$67 billion in future human health benefits. The calculation of these benefits is not clear and cannot be measured or verified. As explained above, it is critical that the reduction in HAPs be accurately determined in order to assist in evaluating the overall projected benefits of the proposed rule. Please summarize the assumptions associated with these projections, the accuracy of these estimates and whether EPA will verify the cost saving estimates. In addition, please explain why this estimate is different from the previous proposed rule estimates.

[Footnotes]

(1) Section V. A. Air Impacts (pg 80620)

(2) Section V. F. Social Costs & Benefits (pg 80622)

Response: The EPA disagrees that benefits of this rulemaking have been inappropriately documented. In fact, the health benefit is fully documented in the Regulatory Impact Analysis that accompanied the final regulation in February 2011 in the docket (also available at http://www.epa.gov/ttn/ecas/regdata/RIAs/boilersriafinal110221_psg.pdf). For this reconsideration, EPA has applied the same methodology to the revised emission reductions reflecting the revised provisions in the reconsideration, which is documented in the December 1st memo to the docket (also available at <http://www.epa.gov/ttn/ecas/regdata/RIAs/boilermactreconria.pdf>). This memo breaks down the benefits changes attributable to the addition of 300 boilers as well as the provision changes

in the reconsideration. For the final reconsideration package, we have added an estimate of the percent reduction in HAP from boilers, as requested by the commenter.

It is important to note that the health benefits are not “cost-savings” as indicated by the commenter. The monetization of the health benefits is largely dominated by willingness to pay to avoid small risks of premature death. The EPA has determined that the proposed rule will lead to reductions of criteria and HAP responsible for significant adverse health effects and that such reductions will produce substantial public health benefits. Accounting for ancillary impacts is standard practice in benefit-cost assessment since these benefits are a consequence of the rule, regardless of the rule’s intended purpose. The EPA estimates all of the anticipated costs and

benefits associated with a regulatory action, to the extent feasible, for the purpose of determining the likely impacts, not to justify an action. This rule is expected to achieve substantial PM2.5 health benefits resulting from primary PM and SO2 emission reductions, and these co-benefits have been included in the regulatory impact assessment. The PM2.5 health benefits anticipated from this rule are based on the best available peer-reviewed science and methods that have withstood scrutiny from EPA's independent Science Advisory Board, the National Academy of Sciences, and continuous interagency review. We further note that we were unable to monetize other important benefits, including health benefits of ozone reductions, additional PM2.5 health benefits, and direct health benefits of reducing SO2. If we were able to fully monetize these benefits, the benefits would exceed the costs by an even greater amount than we currently estimate.

Commenter Name: Dean C. DeLorey

Commenter Affiliation: The Amalgamated Sugar Company LLC (TASCO)

Document Control Number: EPA-HQ-OAR-2002-0058-3522-A1

Comment Excerpt Number: 11

Comment: The proposed monitoring requirements disregard and ignore President Obama's January 2011 Executive Order 13563 for "Improving Regulation and Regulatory Review". The purpose of this order is to identify and correct overly burdensome regulations that impact economic growth. The proposed Boiler MACT monitoring requirements are in direct conflict with this order, especially considering the real public health benefits have never been documented.

Response: The EPA disagrees that the public health benefits have never been documented. In fact, the health benefit is fully documented in the Regulatory Impact Analysis that accompanied the final regulation in February 2011 in the docket (also available at http://www.epa.gov/ttn/ecas/regdata/RIAs/boilersriafinal110221_psg.pdf). For this reconsideration, EPA has applied the same methodology to the revised emission reductions reflecting the revised provisions in the reconsideration, which is documented in the in the December 1st memo to the docket (also available at <http://www.epa.gov/ttn/ecas/regdata/RIAs/boilermactreconria.pdf>). Furthermore, the PM2.5 health benefits anticipated from this rule are based on the best available peer-reviewed science and methods that have withstood scrutiny from EPA's independent Science Advisory Board, the National Academy of Sciences, and continuous interagency review. Hundreds of studies have documented human health risks from exposure to air pollution, including EPA's *Integrated Science Assessment for Particulate Matter* (U.S. EPA, 2009) and the *Integrated Risk Information System* (IRIS) for various hazardous air pollutants.

Commenter Name: Janice E. Nolen

Commenter Affiliation: American Lung Association

Document Control Number: EPA-HQ-OAR-2002-0058-3679-A2

Comment Excerpt Number: 4

Comment: Many face greater risk because of their age, health conditions, or rate of exposure to the pollutants. They include: infants, children and teenagers; older adults; pregnant women;

people with asthma and other lung diseases; people with cardiovascular diseases; diabetics; people with low incomes; and people who work or exercise outdoors (EPA 1997, 2009b). The discussion below highlights special concerns for several of these groups.

Response: The EPA agrees that the scientific literature indicates that certain populations as having a greater likelihood of experiencing health effects related to air pollution than others. In the *Integrated Science Assessment for Particulate Matter* (U.S. EPA, 2009), the EPA concluded that “[o]verall, the epidemiologic, controlled human exposure, and toxicological studies evaluated in this review provide evidence for increased susceptibility for various populations, including children and older adults, people with pre-existing cardiopulmonary diseases, and people with lower SES.” Exposure to fine particulates and toxic air pollutants is associated with many adverse health effects and reducing exposure to these pollutants is associated with substantial public health benefits.

Commenter Name: Janice E. Nolen

Commenter Affiliation: American Lung Association

Document Control Number: EPA-HQ-OAR-2002-0058-3679-A2

Comment Excerpt Number: 6

Comment: People with chronic diseases, including cardiovascular diseases, respiratory diseases and diabetes, face higher risk regardless of age. Their diseases make them at much higher risk for harm. Current estimates include these groups:

- Asthma - 24.6 million people, including 7.0 million under age 18 (American Lung Association, 2011)
- Cardiovascular diseases – 82.6 million people (Roger et al., 2011)
- Diabetes – 25.8 million people (CDC, 2011)

As adults age, their body’s physiological process declines naturally, placing even healthy older adults at risk from airborne pollutants. In addition, many older adults also have one or more chronic diseases that increase their susceptibility (EPA, 2009b).

Response: See the response to comment EPA-HQ-OAR-2002-0058-3679-A2, excerpt 4.

Commenter Name: Janice E. Nolen

Commenter Affiliation: American Lung Association

Document Control Number: EPA-HQ-OAR-2002-0058-3679-A2

Comment Excerpt Number: 8

Comment: Socioeconomic position has been more consistently associated with greater harm from air pollution. Recent studies show evidence of that link. Low socioeconomic status consistently increased the risk of premature death from fine particle pollution among 13.2 million Medicare recipients studied in the largest examination of mortality associated with particulate matter levels nationwide (Zeger et al., 2008).

Response: See the response to comment EPA-HQ-OAR-2002-0058-3679-A2, excerpt 4.

Commenter Name: Janice E. Nolen
Commenter Affiliation: American Lung Association
Document Control Number: EPA-HQ-OAR-2002-0058-3679-A2
Comment Excerpt Number: 3

Comment: Cleaning up these toxic emissions will provide substantial health benefits. The EPA's analysis estimates the health benefits each year beginning in 2015, which includes the prevention of up to 8,100 premature deaths, the avoidance of 5,100 nonfatal heart attacks and the prevention of 52,000 asthma attacks (EPA, 2011b).

In fact, these estimates undercount the total benefits. Studies that would enable researchers to quantify many health endpoints affected by these toxics were not available for modeling. For example, critical, real benefits such as reductions in the number of infants born with low birthweight or impaired cognitive development were not included in the projections. However, the benefits to public health that can be estimated alone provide powerful support to require facilities to meet the strongest possible limits on these toxic emissions. The evidence shows that the strongest possible limits on the emissions of these toxics are both appropriate and necessary.

Response: The EPA agrees that this rule is anticipated to provide substantial health benefits and that many benefits remain unquantified. In the Regulatory Impact Analysis, the EPA estimates all of the anticipated costs and benefits associated with a regulatory action, to the extent feasible. Both Executive Orders 12866 and 13563 acknowledge that many benefits are difficult to quantify. The EPA agrees that we were unable to monetize other important benefits, including health benefits of reducing exposure to hazardous air pollutants, ozone, SO₂, and additional PM_{2.5} health benefits such as low birthweight, as well as ecosystem effects and visibility impairment. These rules are expected to achieve important HAP and criteria pollutant benefits, but monetization of some of these benefits is limited by currently available data and methods. For example, monetization of the HAP benefits of reductions in cancer incidences requires several important inputs, including central estimates of cancer risks, estimates of exposure to carcinogenic HAP, and estimates of the value of an avoided case of cancer (fatal and non-fatal). Our limited ability to monetize these benefits does not indicate that they are non-existent or less important. If we were able to fully monetize these benefits, the benefits would exceed the costs by an even greater amount than we currently estimate.

Commenter Name: Janice E. Nolen
Commenter Affiliation: American Lung Association
Document Control Number: EPA-HQ-OAR-2002-0058-3679-A2
Comment Excerpt Number: 17

Comment: Hazardous Air Pollutants from Boilers and Incinerators Cause Wide-ranging Health Harm

During the process of burning coal, oil, and biomass, boilers and incinerators emit highly toxic chemicals that threaten human health through the air we breathe, the water we drink, and the food we eat. These hazardous air pollutants that harm human health include: corrosive substances (acid gases, such as hydrogen chloride); carcinogens (formaldehyde, benzene, toluene, and other compounds); organic carbon-based toxics (formaldehyde, dioxins, furans);

metals (such as arsenic, nickel, and beryllium); and neurotoxins (such as mercury and lead) (EPA 2007; ATSDR 2011a). They also include criteria air pollutants: sulfur dioxide, carbon monoxide, and fine particulate matter.

Some hazardous pollutants, such as acid gases, mercury, and sulfur dioxide, have immediate impacts on people, neighborhoods, and towns located near boilers or incinerators. However, other pollutants, such as dioxins and metals, can travel much farther from the pollution source. When they adhere to fine particles, these pollutants can remain in the air for more than a week and be carried away by winds to distant locations. This makes toxic air pollution dangerous to public health and human health near and far from these sources (EPA, 2009b).

The discussion below summarizes the evidence that these toxics pose serious threats to health and must be reduced.

Carbon Monoxide. Carbon Monoxide is a colorless, odorless, nonirritating gas that occurs in outdoor and indoor air through both natural and human-made sources (ATSDR, 2009). Exposure to moderate or high levels of this gas can be fatal by causing severe damage to the heart and/or brain (ATSDR, 2009). Breathing high levels may cause a miscarriage for women who are pregnant, and exposure to lower levels can cause permanent damage to the mental development of the fetus (ATSDR, 2009).

Dioxins and Furans (Example: 2,3,7,8-tetrachlorodibenzo-p-dioxin, known as TCDD). Dioxins and furans are a family of toxic chemicals that primarily arise from the burning of fossil fuels, such as coal, and exist in the atmosphere both as a gas and particles. (Oh et al., 2001). As particles, they may remain airborne for more than ten days, spreading widely from their source, and depositing in water and soil (Atkinson, 1991). Dioxins have been found in the U.S. food supply; in 2002-2003, the U.S. Department of Agriculture found dioxin-like substances in meat and poultry (Hoffman et al., 2006). Researchers have found dioxins in the breast milk of nursing mothers (Lorber and Phillips, 2002).

Short-term exposures can cause liver damage and skin lesions, while long-term exposures can harm the immune system, the developing nervous system, the reproductive system, and disrupt hormone function. One form of dioxin—2,3,7,8-Tetrachlorodibenzo-p-dioxin, or TCDD—is recognized as a known human carcinogen. (NTP 2011). (WHO, 2010, 2011; ATSDR, 1994, 1998a, 2000b). Researchers are currently exploring the potential for dioxins to act as endocrine disruptors, by mimicking natural hormones in the body and altering their normal function (Casals-Casas and Desvergne, 2011). Last year, the World Health Organization concluded that the developing fetus and the newborn child were the most vulnerable to dioxin and furan exposure because of the rapid growth of their organ systems (WHO, 2010).

Mercury (Including Methylmercury). Mercury is a primary metal emitted from coal-fired boilers and incinerators. Mercury emissions occur in three forms: as a vaporous gas of elemental mercury; oxidized, and bound with particles. Elemental mercury stays airborne, resulting in widespread distribution. Oxidized and particle-bound mercury deposit nearer to the sources. Once released to the atmosphere, mercury returns to the earth in rain or snowfall, and pollutes waterways and the wildlife in them (EPA, 2011) Microorganisms convert mercury into methylmercury, a highly toxic form of mercury that bioaccumulates in fish and shellfish (ATSDR, 1999b; Grandjean, 2010). Although a person can be exposed to mercury through breathing contaminated air or through skin contact, methylmercury is most easily absorbed by

eating contaminated food, especially fish or shellfish. The long-term, low-level exposure to methylmercury that results from the regular consumption of contaminated fish is a primary health concern (EPA, 1997). Eating foods containing methylmercury can expose the brains of adults, children and developing fetus to harm. Critical periods are during pregnancy and in the early months after children are born (ATSDR 1999b). Mercury exposure can lead to developmental birth defects and interfere with neurological development (Bose-O'Reilly et al., 2010). Pregnant women who consume fish and shellfish can transmit that methylmercury to their developing fetuses, and infants can ingest methylmercury in breast milk. Children can also become exposed by eating contaminated fish (ATSDR 1999). Each year, more than 300,000 children born in the US have levels of mercury in their blood high enough to impair performance on brain development test and permanently affect intelligence (Trasande et al., 2005; Axelrad et al., 2007). Mercury can damage the kidneys, liver, brain, and nervous system as a potent neurotoxin, even in adults (ATSDR, 1999b, 2011a; WHO, 2011). A recent study has also found that methylmercury exposure may lessen the cardiovascular benefits of regular fish consumption (Domingo, 2007).

Fine Particulate Matter (PM_{2.5}). Reductions in sulfur dioxide and nitrogen oxides through the final boiler and incinerator standards would provide a crucial collateral benefit: reduction in secondary fine particulate matter. Sulfates formed from sulfur dioxide comprise the majority of fine particulate matter in much of the United States, especially in the summer months. Nitrates from nitrogen oxides are also a major source of fine particulate matter in the fall, winter and spring (EPA, 2011). PM_{2.5} is made up of microscopic particles, including aerosols, that can bypass the body's natural defenses and lodge deep within the lungs (EPA, 2004, 2009). Fine particles elevate risk of heart attacks and strokes (Dominici et al., 2002; Hong et al., 2002; Franklin et al., 2007; D'Ippoliti et al., 2003; Miller et al., 2007); stunt lung function and development (Gauderman et al., 2002; Gauderman et al., 2004); inflame and damage lung tissue and airways (Ghio et al., 2000; Churg et al., 2003); increase hospital visits for respiratory and cardiovascular problems (Dominici et al., 2006; Tsai et al., 2003); and aggravate asthma attacks (Lin M et al., 2002; Norris et al., 1999; Tolbert et al., 2000; Slaughter et al., 2003; Lin S et al., 2002). The evidence shows that PM 2.5 causes cardiovascular harm and is likely to cause respiratory harm. More seriously, PM_{2.5} can cause premature death from lung cancer and cardiovascular effects and is likely to cause death from respiratory effects as well (Pope et al., 2002; Pope et al., 2004).

The most vulnerable populations, including children, teens, senior citizens, people with low incomes and people with chronic lung disease, such as asthma, chronic bronchitis, and emphysema, are at risk of being sickened by fine particulate matter. People with diabetes, heart disease, high blood pressure, coronary artery disease, and congestive heart failure, are also at risk (EPA, 2004, 2009). The evidence suggests that long-term exposure to PM_{2.5} causes reproductive and developmental effects as well as cancer, mutagenicity and genotoxicity (EPA, 2009).

Non-Mercury Metals. Non-mercury metals and metal-like substances (e.g. arsenic and selenium) comprise a significant part of fine particulate matter (PM_{2.5}) emitted from boilers and incinerators. These primary particles come in addition to the secondary particles formed as a result of chemical reactions in sulfur dioxide and nitrogen oxide emissions. Those secondary particles, notably sulfates and nitrates, pose similar life-threatening risks. Inhaled particles deposit along the respiratory tract or penetrate deeply into the gas-exchange region of the lung.

The EPA has already concluded that exposure to fine particulate matter (PM_{2.5}) causes cardiovascular effects and premature mortality and is likely to cause respiratory harm. They concluded that the evidence suggests that long-term exposure to PM_{2.5} causes reproductive and developmental effects as well as cancer, mutagenicity and genotoxicity (EPA, 2009).

The risks of cardiovascular harm include acute myocardial infarction, congestive heart failure, cardiac arrhythmias and strokes. Risks of respiratory harm include coughing, wheezing, difficulty breathing, asthma exacerbations, and increased hospitalization for chronic obstructive pulmonary disease (COPD) (EPA 2009). Evidence has also grown to warn that long-term exposure to PM 2.5 can increase the risk of low birth weight and infant mortality, as well as cancer, especially lung cancer (EPA, 2009).

The level of toxicity of fine particles varies and is likely impacted by the presence of metals or other pollutants (Bell et al., 2007). Metals interact with particles to create —reactive oxygen species|| which limit the body’s ability to repair damage to its cells and contribute to tissue inflammation (Carter et al., 1997; Gurgueira et al., 2002; Wilson et al., 2002). Research has shown that sulfate, selenium, iron, nitrate, and organic carbon affect immune cell response and heart variability (Huang et al., 2003; Chuang et al., 2007). Elevated presence of chromium, lead, and other metals in PM has been associated with greater effects on hospital admissions for cardiovascular disease, according to a study of Medicare recipients in 26 communities (Zanobetti et al., 2009). Zanobetti et al. found that admissions for heart attacks were higher where the PM was enriched in arsenic, chromium, manganese, nickel, and organic carbon. The same study found that high levels of arsenic, organic carbon, and sulfate in PM—potential indicators of coal combustion—were associated with increased hospital admissions for diabetics (Zanobetti et al., 2009). A large study of 25 U.S. communities found more deaths when the fraction of aluminum, sulfate, and nickel in PM was highest (Franklin et al., 2008). This study found additional evidence warning that the combination of metals in particles, a common occurrence, may increase their toxicity.

Arsenic. Arsenic exposure can occur through the dermal, oral, and inhalation routes. As a known carcinogen, inhalation of arsenic has been strongly associated with lung cancer (HHS, 2011). Short-term inhalation can harm the gastrointestinal tract, cause nausea and diarrhea, and even adversely affect the nervous system. Long-term inhalation has been associated with irritation of the skin and mucous membranes. Exposure can lead to respiratory tract irritation and conjunctivitis, and damage nasal tissue (ATSDR, 1998b). Similar to effects of inhaling arsenic, arsenic in drinking water has also been linked to skin, bladder, lung, and liver cancer (HHS, 2011). Over a long period, the metal-like substance can result in anemia, lesions, liver, kidney, and nerve damage, and affect the digestive system (ATSDR, 2007c).

Beryllium. Beryllium is a known carcinogenic metal (HHS, 2011). Inhaled beryllium has been found to increase the risk of lung cancer (Steenland and Ward 1991, Ward et al., 1992). Breathing large amounts of beryllium compounds can damage the lungs and cause the lungs to resemble pneumonia with reddening and swelling. Long-term exposure over many years may cause chronic beryllium disease, when a chronic inflammatory reaction, called a granuloma, within people who are allergic to beryllium occurs. People with chronic beryllium disease may experience weakness, fatigue, difficulty breathing, anorexia, weight loss, and blueness of the hands and feet. The disease can lead to heart enlargement, heart disease, and even death (ATSDR, 2002).

Cadmium. Cadmium is another known carcinogenic metal (HHS, 2011). Exposure to airborne cadmium causes lung cancer, as the International Agency for Research on Cancer reaffirmed in 2009 (Straif, et al., 2009). Prolonged inhalation of cadmium can also lead to gradual accumulation of the metal in the kidneys, resulting in kidney disease (ATSDR, 2008a).

Chromium. Chromium occurs in three main forms, one of which, chromium (IV) is a known carcinogen that can increase the risk of lung cancer (ATSDR, 2008b; HHS, 2011). The metal primarily affects the respiratory system, though chromium (VI) can impact the gastrointestinal, immunological, hematological, reproductive and developmental systems, particularly if ingested. Inhaling chromium (VI) can cause coughing and wheezing, shortness of breath, bronchitis, pneumonia, decreased lung function, and other respiratory conditions. In some workers, inhaled chromium (VI) caused them to develop asthma and have asthma attacks (ATSDR, 2008b).

Lead. The health effects of lead exposure mainly focus on the nervous system and damaging its functions. Lead may cause weaknesses in the joints, anemia, and increases in blood pressure (ATSDR, 2007d). Although lead is harmful to both adults and children, children are most susceptible to the effects of lead exposure. Lead exposure can cause developmental disorders whose effects can persist beyond childhood (ATSDR, 2007e). Exposure can affect a child's physical and mental growth, resulting in slower mental development and lower levels of intelligence. Lead is also a probable carcinogen (HHS, 2011).

Manganese. Similar to lead, manganese mostly affects the nervous system. For example, adverse effects to hand-eye coordination, hand steadiness, and visual reaction time were observed in humans exposed to manganese (ATSDR, 2008c). High exposure levels may result in feelings of lethargy and weakness, psychological impacts, and tremors.

Nickel. Compounds containing nickel have been determined to be carcinogenic (HHS, 2011). A known health effect of nickel exposure is the increased risk of lung and nasal cancers from nickel dust (ATSDR, 2005b).

Selenium. Selenium exposure can harm the respiratory system by irritating mucous membranes and causing pneumonia, bronchitis, and pulmonary edema (ATSDR, 2003a). One selenium compound, selenium sulfide, is also considered to be a probable human carcinogen (HHS, 2011).

Volatile Organic Compounds (Examples: acetaldehyde, benzene, formaldehyde, toluene, xylene). Volatile organic hazardous air pollutants are specific toxic gases that react easily with other gases and particles. These take in a host of chemicals that include carcinogens and other toxins. While many of these toxic air pollutants can cause cancer, they can also irritate the eyes, skin, and respiratory tract, impair lung function, and affect vital organs. Benzene and formaldehyde are recognized as known human carcinogens, while ethylbenzene and acetaldehyde are considered probable carcinogens (HHS, 2011). Long-term exposures to benzene can cause leukemia, a blood cancer, and other blood disorders such as anemia and depressed lymphocyte count in blood. Exposure to formaldehyde can also cause chronic bronchitis and nasal epithelial lesions. A recent review of the research found evidence that formaldehyde may increase the risk of asthma, particularly in the young (McGwin et al., 2010). Non-cancer effects associated with exposure to these organics range from irritation of the skin, eyes, nose, throat, and respiratory tract, and dizziness, nausea, and vomiting. These compounds can also cause difficulty in breathing, impaired lung function and respiratory symptoms, damage

to the liver and kidneys, and stomach discomfort. They may also cause developmental disorders, adverse effects to the nervous system, impairment of memory and neurological function, and slow response to visual stimuli. These pollutants can also affect hearing, speech, vision, and motor coordination (ATSDR, 1999a, 1999c, 2000a, 2007a, 2007b, 2010a).

Sulfur Dioxide (SO₂). Sulfur dioxide (SO₂) a gaseous air pollutant composed of sulfur and oxygen. The sulfur dioxide standard will help reduce this harmful pollutant, long recognized for its harm to health. Sulfur dioxide causes a range of harmful effects on the lungs, including wheezing, coughing, shortness of breath and chest tightness, and other problems, especially during exercise or physical activity. Continued exposure at high levels aggravates asthma, increases respiratory symptoms, and reduces the ability of the lungs to function. Short exposures to peak levels of SO₂ in the air can make it difficult for people with asthma to breathe when they are active outdoors. Rapid breathing during exercise helps SO₂ reach the lower respiratory tract, as does breathing through the mouth. SO₂ pollution increases the risk of hospital admissions or emergency room visits, especially among children, older adults, and people with asthma (EPA, 2009a). In addition, sulfur dioxide poses another threat to human health by reacting in the air to form sulfates (SO₄) which exist as aerosolized fine particulate matter (PM 2.5), another harmful air pollutant discussed below (EPA, 2009).

Nitrogen Oxides (NO_x). Nitrogen oxides (NO_x) are a class of gaseous air pollutants composed of nitrogen and oxygen. NO_x is emitted during the combustion of natural gas in engines, turbines, heaters, and boilers during production and processing operations for oil and gas wells. NO_x is also emitted during pit flaring of VOC emissions from well completions. The pollutant itself can inflame the airways and reduce lung function, worsened cough and wheezing, increase asthma attacks and hospital visits; and increase risk of respiratory infection (EPA, 2008). EPA's own review of the science found that exposure to NO_x can increase the risk of hospitalization by up to 20 percent (EPA, 2008). Nitrogen oxides are also precursors to nitrates (NO₃) which also are recognized as aerosolized fine particulate matter (PM 2.5) and discussed below. (EPA 2008)

Hydrogen chloride (HCl). Hydrogen chloride is a strong acid gas that reacts with moisture to form hydrochloric acid. Hydrogen chloride intensely irritates the mucous membranes of the respiratory system. At high concentrations, hydrogen chloride can cause swelling and spasms in the throat and suffocation. In addition, inhaled hydrogen chloride can lead to a chemical- or irritant-induced form of asthma called Reactive Airway Dysfunction Syndrome (RADS). (ATSDR, 2010b). Both hydrogen chloride and hydrogen fluoride can irritate the eyes, nasal passages, and lungs (EPA 2000a, 2000b).

Response: The EPA agrees that exposure to fine particles and hazardous air pollutants is associated with many adverse health effects and reducing exposure to these pollutants is associated with substantial public health benefits.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 75

Comment: EPA's total claimed monetized benefit of \$27 billion to \$67 billion, of which \$25 billion to \$65 billion is due to the co-beneficial removal of SO₂ rather than the control of HAPs, should be reduced commensurately. Reducing the co-benefit attributable to SO₂ by a factor of between two and six would produce a more realistic monetized benefit of between \$4 billion and \$33 billion.

Response: We disagree that the estimated co-benefits of controlling SO₂ emissions should be reduced by a factor between 2 and 6. The SO₂ emissions reductions are based on actual SO₂ emissions reported by industry and contained in the Boiler MACT emission database. For units that did not report SO₂ emission test, average baseline emission factors were developed using data from other boilers and process heaters with similar controls, fuels, and combustor designs. The SO₂ emission reductions analysis for existing combustion units was done for each boiler and process heater in the major source inventory. Each combustion unit was assigned a unit-specific or average baseline SO₂ emission factor, depending on the availability of emission data reported for the unit. In the impact analysis, a combustion unit is required to install a scrubber for HCl control if it is not currently meeting the HCl floor limit, and if it doesn't already have a scrubber installed. For units required to install a scrubber, it was assumed that the scrubber will achieve a 95 percent reduction from baseline for SO₂. To calculate emission reductions for SO₂, baseline emissions were multiplied by a factor of 0.95. This resulted in the total SO₂ reductions used in the benefits analysis.

16B. Executive Order 13132, Federalism

Commenter Name: Tangela Niemann

Commenter Affiliation: Texas Commission on Environmental Quality (TCEQ)

Document Control Number: EPA-HQ-OAR-2002-0058-3594-A3

Comment Excerpt Number: 9

Comment: By mandating case-by-case review and approval of the emissions averaging plans in §63.7522 and the emission credit plans in §63.7533, the EPA is imposing requirements and additional work on the agencies tasked with enforcing these rules and the EPA must account for the fiscal impact. The fact that the EPA proposed these provisions by specifically stating the delegated authority must review and approve the plans indicates that the EPA fully intends for the states to perform this work. The additional work created by these case-by-case review requirements in the rule is above and beyond the resources necessary for the state to accept enforcement authority of the rule, and the EPA should have accounted for the impact to the state agencies in the fiscal analysis and regulatory impact analysis for 40 CFR 63 Subpart DDDDD. The TCEQ has found no such impact analysis regarding these requirements in the current proposal or with the March 21, 2011, adoption of the final rule.

In the preamble of the recently finalized utility NESHAP rule, 40 CFR 63 Subpart UUUUU, the EPA indicated that "While the EPA has not prepared an analysis of the impacts of the rule on state programs, the Agency does not believe the rule will be unduly burdensome to the state regulatory agencies." If the EPA did not analyze the impact of the utility NESHAP rule on state agencies, then the EPA has no basis for claiming it is not a burden on state agency resources. Since the EPA has not provided any analysis of the impact of these requirements on state agencies for 40 CFR 63 Subpart DDDDD, the TCEQ concludes that the EPA has made the same

assumption that the review and approval of the implementation plans is not a burden to the states. The EPA has an obligation to evaluate the impact of its regulations on the agencies that will be expected to implement the EPA's rules. State agencies do not have unlimited resources available to implement whatever requirements the EPA decides to include in its rules. The EPA cannot just assume its rules are not costly or burdensome to state environmental agencies as it did with the utility NESHAP rule. If the EPA has not considered the number of staff hours required to review and approve the implementation plans on a case-by-case basis, the possible total number of facilities requesting approval of emissions averaging and emission credit implementation plans, and the approximate cost to state agencies to perform these reviews, then the EPA does not know the burden it is imposing of the states.

Response: We agree that the EPA has an obligation to evaluate the impact of its regulations on the agencies that will be expected to implement the EPA's rules. We realize that State agencies do not have unlimited resources available to implement whatever requirements the EPA decides to include in its rules. We disagree that the EPA just assume its rules are not costly or burdensome to state environmental agencies. However, we did not considered the number of staff hours required to review and approve the implementation plans on a case-by-case basis, the possible total number of facilities requesting approval of emissions averaging and emission credit implementation plans, and the approximate cost to state agencies to perform these reviews. Based on similar comments from other State agencies, the final rule have been revised to remove the requirement mandating case-by-case review and approval of the emissions averaging plans in §63.7522 and the emission credit plans in §63.7533. In both sections, the requirement has been revised from "must ... submit to ... for review and approval.." to "submit upon request..." In both cases the source must still prepare the plan.

Commenter Name: Tangela Niemann

Commenter Affiliation: Texas Commission on Environmental Quality (TCEQ)

Document Control Number: EPA-HQ-OAR-2002-0058-3594-A3

Comment Excerpt Number: 10

Comment: While the TCEQ supports flexibility in regulatory implementation by providing options for compliance such as the emissions averaging approach, the rule provisions to implement these options should be designed as much as possible to allow for implementation without case-by-case review and approval. The EPA has revised the utility NESHAP rule emission averaging plan requirements to only require review and approval of the emissions averaging implementation plans upon request by the administrator and, as discussed elsewhere in these TCEQ comments, the TCEQ is requesting the EPA make the same change to the §63.7522 and §63.7533. If the emissions averaging option or the emission credit option cannot be implemented without a case-by-case review of each implementation plan, the EPA should reevaluate §63.7522 and §63.7533 to determine if revisions are necessary to ensure appropriate self-implementation or if the options should be removed from the final rule. If the mandatory case-by-case review of the implementation plans remains a requirement in the final rule, the EPA has an obligation to evaluate and disclose the impact that has on the state agencies.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3594-A3, excerpt 9.

Commenter Name: Myra Reece

Commenter Affiliation: South Carolina Department of Health and Environmental Control

Document Control Number: EPA-HQ-OAR-2002-0058-3629-A2

Comment Excerpt Number: 1

Comment: Emission Credits Earned From Implementation Of Energy Conservation Measures To Demonstrate Compliance With This Rule Cannot Be Effectively Implemented Or Enforced By Approving Implementation Plans

The emission credit compliance approach in Section 63.7533 requires facilities electing to use this compliance option to submit an “Implementation Plan” to the delegated authority for review and approval. The Implementation Plan shall identify all existing affected boilers to be included in applying the emission credits and include a description of the energy conservation measures implemented, the energy savings generated from each measure, and an explanation of the criteria used for determining savings.

There is no clear justification to require that the delegated agencies approve the Implementation Plans nor is there a clear explanation of its benefit in the preamble of the rule. A more efficient process would be requiring facilities electing this compliance option to submit the Implementation Plan requirements specified in Section 63.7533(d) within the Notification of Compliance Status (NOCS) required by Section 63.7545. While DHEC appreciates that it has been granted authority to administer the requirements under 40 CFR 632, it is clear that the EPA is not considering the additional burden the Implementation Plan approval process will pose to the already limited resources of delegated agencies and is downplaying the complexities of implementing and enforcing the emission credit compliance option.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3594-A3, excerpt 9.

Commenter Name: Myra Reece

Commenter Affiliation: South Carolina Department of Health and Environmental Control

Document Control Number: EPA-HQ-OAR-2002-0058-3629-A2

Comment Excerpt Number: 4

Comment: The EPA proposes to require facilities choosing to demonstrate compliance by the emission averaging option to submit an “Implementation Plan” for review and approval by the delegated authority. However, the EPA did not provide a clear process for implementing and enforcing this complex compliance option. We strongly request that the EPA eliminate the requirement for delegated authorities to approve implementation plans and instead develop an emission averaging certification mechanism within the Notice of Compliance Status (NOCS). The NOCS process is established, and states have experience implementing it.

As stated in our comment letters on the proposed Boiler and Utility MACT dated August 17, 2010 and July 20, 2011 respectively, DHEC received several implementation plans from facilities trying to comply with the vacated Boiler MACT in 2007. We encountered many problems with the approval process and received little help and guidance from the EPA. The EPA proposed the same approval process in this Boiler MACT reconsideration, disregarding the

known problems states faced in 2007 trying to implement the emission averaging compliance option in the vacated Boiler MACT.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3594-A3, excerpt 9.

Commenter Name: Myra Reece

Commenter Affiliation: South Carolina Department of Health and Environmental Control

Document Control Number: EPA-HQ-OAR-2002-0058-3629-A2

Comment Excerpt Number: 5

Comment: We believe that the requirement to establish an emission cap and submit an implementation plan to the permitting agencies for approval is problematic as written. Because the emission cap is not used in the initial compliance demonstration or in demonstrating continuous compliance with the emission averaging option, it is of little use.

If the intent of this option is for facilities to not exceed the cap at any time, then the EPA should include a demonstration methodology that shows that a facility is not exceeding the cap in the compliance equations in section 63.7522. If the cap is included in the compliance equations, facilities could certify compliance with the cap in the NOCS and within each required semiannual report. Additionally, if the initial and continuous compliance measures include the emission cap, the implementation plan will not be necessary and states will not have to spend valuable time and resources to approve these duplicative plans.

As stated previously, DHEC received several implementation plans from facilities trying to comply with the vacated Boiler MACT in 2007. We encountered many problems with the approval process and received little help and guidance from the EPA.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3594-A3, excerpt 9.

Commenter Name: Myra Reece

Commenter Affiliation: South Carolina Department of Health and Environmental Control

Document Control Number: EPA-HQ-OAR-2002-0058-3629-A2

Comment Excerpt Number: 6

Comment: Requirement For Delegated Agencies To Approve Implementation Plans Is Burdensome And Unnecessary. The EPA Should Provide Specific Guidance And Examples On What Constitutes An Acceptable Emission Cap.

The requirement to establish an emission cap and submit an implementation plan to the permitting agencies for approval is problematic as written. DHEC noted this issue in our comments for the 2010 proposed Boiler MACT. While the EPA attempted to correct the enforceability problem related to the emission cap in the final Boiler MACT by requiring facilities to report the emission cap in the NOCS (see 40 CFR 63.7545(e)(5)(i)), and certify compliance with the cap in the compliance reports (see 40 CFR 63.7550(c)(13)), there is no guidance or clear process on what constitutes an acceptable and enforceable emission cap that delegated agencies can follow to approve the cap.

If the EPA decides that the submittal and approval of implementation plans are necessary for the emission averaging compliance option, DHEC believes that the EPA should retain the authority to approve the implementation plans.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3594-A3, excerpt 9.

16D. Executive Order 13045, Protection of Children from Environmental Health Risks and Safety Risks

Commenter Name: Janice E. Nolen

Commenter Affiliation: American Lung Association

Document Control Number: EPA-HQ-OAR-2002-0058-3679-A2

Comment Excerpt Number: 5

Comment: Children face quite different risks from air pollutants than adults. The lungs and their alveoli are not fully grown until children become adults (Dietert et al., 2000). Biological defenses that help adults fight off infections are still developing in young bodies (WHO, 2005). Furthermore, children don't behave like adults, and their behavior also affects their vulnerability. They are outside for longer periods and are usually more active when outdoors. Consequently, they inhale more polluted outdoor air than adults typically do (AAP, 2004). Toxic substances may put children more at risk than adults. For example, the California Environmental Protection Agency explored improved methodologies to determine susceptibility to carcinogens in utero and childhood after finding in 2001 that the existing approaches did not adequately reflect the risks to children. Their subsequent research found that the children generally display greater sensitivity to environmental carcinogens than did adults (CalEPA, 2009).

Response: Exposure to methylmercury is associated with substantial public health effects. For more information on the health effects associated with mercury, please consult <http://www.epa.gov/mercury>.

16F. Regulatory Flexibility Act as Amended by the Small Business Regulatory Enforcement Fairness Act (RFA) of 1996 (SBREFA), 5 U.S.C. 601 et Seq.

Commenter Name: Douglas A. McWilliams

Commenter Affiliation: American Municipal Power

Document Control Number: EPA-HQ-OAR-2002-0058-3685-A2

Comment Excerpt Number: 3

Comment: It Would Be Arbitrary for EPA to Ignore the Advice of the Small Business Advocacy Panel Given the Increased Stringency of the HCI Limits

The Regulatory Flexibility Act ("RFA") requires EPA to analyze the impacts of its rules on small entities (including small government entities) for rules that will have a significant impact on a substantial number of small entities. 7 To assist with this analysis, EPA convened the SBA Review Panel to recommend ways the Agency could alleviate the rule's impacts on small businesses and governments. The Small Business Advocacy Review Panel identified HBELs as *"the most important step* EPA could take to mitigate the serious financial harm the Boiler MACT

would otherwise inflict on small entities using solid fuels nationwide ... "8 All of AMP's generating members now anticipate needing controls to comply with the proposed HCI limits. Even the best-performing AMP member must now concede that fuel management may not be a sufficient strategy to meet an emission limit of 0.022 lb/mmBtu. Given the increased stringency of the HCI limit in the Proposed Rule, it is likely that many more entities would be forced to install controls than under the March 2011 rule.

EPA estimated a median compliance cost for small public entities of \$1.1 million, with cost-to-revenue ratios greater than 10 percent.⁹ EPA has estimated no change in costs for these entities, despite proposing more stringent emission limits on coal-fired units for nearly every pollutant. Furthermore, AMP provided EPA with additional cost information in the 2010 AMP Comments that demonstrated many entities will experience significantly higher annual costs. The City of Orrville and the City of Painesville have independently evaluated the cost of controlling HCI emissions at their coal-fired electric utilities and determined that the capital cost for a single unit would reach \$5-16 million, with annual operating costs between \$900,000 and \$1.2 million. The City of Painesville operates three boilers, and the City of Orrville operates four. These facilities would incur \$3-4 million in operating costs each year *for HCI control alone*.¹⁰ Many small entities will be unable to absorb these unnecessary costs and be forced to severely curtail or shutdown operations entirely. This would significantly hinder municipal utilities' ability to provide reliable electrical services to their communities, grid support during high demand periods to avoid brownouts, and quality work opportunities for local residents. Adopting MACT standards that force small entities to severely curtail or eliminate operations is contrary to the intent of Congress, which has stated that "MACT is not intended to . . . drive sources to the brink of shutdown." House REP. No. 101-490, Part 1 (1990) at 328. But that is precisely what will happen to small entities under the Proposed Rule unless changes are made.

[Footnote 7: 5 U.S.C. § 603.]

[Footnote 8: SBA REVIEW PANEL, FRNAL REPORT at 23 (emphasis added).]

[Footnote 9: Memorandum from Tom Walton to Brian Shrager, re: Regulatory Impact Results for the Reconsideration Proposal for National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters at Major Sources (Dec. 1, 2011). 10 This represents \$33,000 per customer in capital costs and an additional \$3,000 per customer for annual operating costs.]

Response: The EPA appreciates the concerns of the regulated small entities. During this rulemaking process we have incorporated several suggestions from the small business panel, and we made several changes in the March, 2011 final rule (76 FR 15608) to reduce the burden on all sources, including small entities. The EPA has maintained its consideration of small sources in the final rule. See the Final Regulatory Flexibility Analysis (FRFA) section of the Regulatory Impact Analysis (RIA) which has been prepared for this rule for further discussion of the impact on small entities.

Commenter Name: Douglas A. McWilliams
Commenter Affiliation: American Municipal Power

Document Control Number: EPA-HQ-OAR-2002-0058-3685-A2

Comment Excerpt Number: 6

Comment: EPA has articulated no legitimate reason for ignoring the advice of the SBA Review Panel, which was convened for the express purposes of helping EPA to analyze the impact of the Boiler MACT rule on small entities. The Panel 's recommendations are even more relevant now that EPA has proposed to reduce the HCI limit by an additional 30 percent. EPA did not adequately consider and analyze regulatory options to reduce the impact of the rule on small government entities as required by the RFA and UMRA, and has acted arbitrarily and capriciously in rejecting the SBA Review Panel's recommendations using meritless arguments.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3685-A2, excerpt 3 for discussion of impact on small entities.

Commenter Name: Douglas A. McWilliams

Commenter Affiliation: American Municipal Power

Document Control Number: EPA-HQ-OAR-2002-0058-3685-A2

Comment Excerpt Number: 8

Comment: Including a Health-Based Emission Limit Alternative for Small Entities Is Supported by the Record

AMP and numerous other commenters provided EPA with significant legal and factual support for including HBELs in the final rule, and demonstrated that EPA's concerns were unfounded. EPA has offered no legitimate justification for ignoring this data and refusing to adopt an HBEL. EPA's actions are even more problematic in light of the Proposed Rule, in which EPA has imposed even more stringent HCI limits than in the March 2011 rule. Municipalities have been hit particularly hard by the economic downturn, as federal and state money and local tax revenues have declined sharply since 2008. They face severe budget constraints that are driving difficult resource allocation choices. Congress gave EPA a tool to mitigate cost when relaxed limits are adequately protective, and EPA should use this tool to mitigate some of the burden on small entities and small governments. Given all of the data now before the Agency, it would be arbitrary and capricious for EPA to publish a final rule that sets HCI limits that are far more stringent than necessary to protect human health and the environment.

EPA could avoid this arbitrary and capricious finding and avoid violating the RFA by crafting an HBEL alternative for those units operated by qualifying small entities under the RFA. EPA has ample authority for adopting an HBEL for HCI, and doing so here would harmonize EPA's actions with the findings it made - and never refuted - in the 2004 Boiler MACT rule. If EPA is unwilling to include a blanket HBEL for HCI in the final rule, the rule should, at minimum, include a provision allowing small entities to petition for an HBEL on a site-specific basis. Because the petition process would be limited to small entities, the number of potential petitions would be limited to a manageable number. Site-specific evaluations would allow for an evaluation of potential cumulative impacts from nearby sources and provide sources an opportunity to demonstrate that they can adequately protect human health and the environment without wasting millions of dollars on unnecessary controls. Preserving the possibility of a site-specific HBEL through a petition process will provide necessary relief to small entities without

compromising human health or the environment and without necessitating a complete rewrite of the HCI standards in the final rule.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3685-A2, excerpt 3 for discussion of impact on small entities.

Commenter Name: Dan Bosch

Commenter Affiliation: National Federation of Independent Business (NFIB)

Document Control Number: EPA-HQ-OAR-2002-0058-3460-A2

Comment Excerpt Number: 1

Comment: NFIB's comments will focus solely on the cost and compliance burden these rules will impose on small businesses. We are greatly concerned that even though many emissions limits have been lowered and other improvements in flexibility have been made, these rules are simply too costly and complex for affected small businesses to comply without serious economic harm.

Regulation affects small businesses in a substantially different way than it does large businesses. When a large business needs to comply with a new regulation, it designates its regulatory compliance officer – or officers – with the task. These individuals know their way around regulatory technicalities that most lay persons do not easily understand.

For the small-business owner, there is no regulatory compliance officer. This burden falls squarely on the owner, who, more times than not, is responsible for everything from ordering inventory and hiring employees, to taking out the trash at the end of the day. And while they may be expert in their craft, comprehending regulations, formalizing plans for their implementation and filling out paperwork is an extremely burdensome exercise.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3685-A2, excerpt 3 for discussion of impact on small entities.

Commenter Name: Dan Bosch

Commenter Affiliation: National Federation of Independent Business (NFIB)

Document Control Number: EPA-HQ-OAR-2002-0058-3460-A2

Comment Excerpt Number: 2

Comment: Even beyond the significant time regulations take away from a small-business owner trying to make a living, the per-employee cost of regulation is significantly greater for small businesses. The U.S. Small Business Administration's Office of Advocacy released a study in 2010 that showed the smallest businesses – those with fewer than 20 employees – spend 36 percent more per employee per year complying with federal regulations¹. Alarming, that disproportionality increases to 364 percent when it comes to environmental regulation. These findings do not suggest that all regulation is bad or unnecessary, but rather clearly demonstrate that agencies need to take extra care to make sure their regulations are well-reasoned and flexible. Without such flexibility, the ability of small businesses to grow and create jobs is severely inhibited.

This regulatory scheme is among the most complex in recent memory and as such, the compliance burdens presented by these rules are vast. Small-business owners will need to spend significant time to attempt to understand these rules, make expenditures to expensive consultants to bring the facility up to compliance, and greatly increase the amount of time he or she spends on paperwork compliance. The result will have serious and harmful consequences for the small businesses forced to comply with these rules. [Footnote]

(1) <http://archive.sba.gov/advo/research/rs371tot.pdf>

Response: See the response to comment EPA-HQ-OAR-2002-0058-3685-A2, excerpt 3 for discussion of impact on small entities.

Commenter Name: Dan Bosch

Commenter Affiliation: National Federation of Independent Business (NFIB)

Document Control Number: EPA-HQ-OAR-2002-0058-3460-A2

Comment Excerpt Number: 3

Comment: NFIB suggests that to improve these rules further, the EPA should adopt the suggestions the small-entity representatives provided the agency during the Small Business Advocacy Review

(SBAR) panel held in 2009. Though some of these suggestions have been proposed, such as additional subcategories for boilers, other recommendations have not been proposed that we believe would lessen the compliance burden for small businesses. These recommendations include:

- Allowing facilities meeting the SBA definition of a small business to have reduced and less frequent monitoring, testing and reporting requirements;
- Allowing facilities to use work practice standards rather than emission limits for additional pollutants;
- Adopting health-based compliance options in areas where there is no significant risk to nearby residents;
- Requiring annual boiler tune-ups as a way to improve boiler efficiency instead of emissions standards; and

Exempting area sources from Title V permitting requirements.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3685-A2, excerpt 3 for discussion of impact on small entities.

Commenter Name: Bart Sponsellar

Commenter Affiliation: Wisconsin Department of Natural Resources (DNR)

Document Control Number: EPA-HQ-OAR-2002-0058-3527-A1

Comment Excerpt Number: 2

Comment: Another major concern we have regards the intensity of compliance requirements for sources subject to emission limitations. We believe that with further work on the rule, costs

can be significantly reduced while achieving the same or better environmental improvement. Once again, we are especially concerned for small sources which contribute significantly less in emissions but are subject to the same intensity of compliance requirements — specifically annual performance testing.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3685-A2, excerpt 3 for discussion of impact on small entities.

16G. Paperwork Reduction Act

Commenter Name: John V. Corra, Director

Commenter Affiliation: State of Wyoming Department of Environmental Quality

Document Control Number: EPA-HQ-OAR-2002-0058-3435-A1

Comment Excerpt Number: 2

Comment: EPA has provided cost estimates for the annual monitoring, recordkeeping, and reporting burdens that companies and the Federal government will incur, as well as total yearly labor costs. No estimate of the associated burden on state and local governments was provided. Wyoming recommends that EPA estimate and report the additional burden that the reconsidered rules place on state and local governments. The evaluation should consider the development of staff expertise necessary to evaluate energy assessments, as well as the addition of staff resources needed to effectively review industry's annual monitoring, reporting and recordkeeping requirements.

Wyoming believes that EPA should also evaluate the permitting burden placed on states, as companies may need to make process modifications to be more energy efficient. Permitting entities with minor source authority, such as Wyoming, may be faced with additional permit applications to address equipment changes associated with improving energy efficiency, especially if the equipment modifications are beyond insignificant or like-kind replacement. Energy efficiency could also bring into question the applicability of Prevention of Significant Deterioration review for increased capacity, process optimization, or increased reliability that may not result in a permit but will require the facility, and possibly the permitting authority, to evaluate.

Response: The EPA appreciates the concerns related to the burden on state agencies. The Agency revised permitting provisions in the March, 2011 final rule notice (76 FR 15608) to reduce the burden on states. These revised permitting provisions have been retained in the final rule.

16I. Executive Order 12898, Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations

Commenter Name: Janice E. Nolen

Commenter Affiliation: American Lung Association

Document Control Number: EPA-HQ-OAR-2002-0058-3679-A2

Comment Excerpt Number: 2

Comment: The EPA estimates that 1.5 million boilers and 95 solid waste incinerators are in use throughout the United States (EPA, 2011b; EPA, 2011c). Boilers and process heaters comprise some of the most common industrial equipment, but they also provide heat and power to commercial buildings and institutions, such as churches, colleges and hospitals. Because boilers are so widely used, their toxic emissions can threaten local communities, especially lower income or minority communities that are often located closer to the larger industrial sources.

Response: "Nearness" to a source is not necessarily an indicator of greater "harm." However, we believe that the controls placed on these combustion units by this rule will substantially reduce emissions and will result in positive benefits to all those communities previously impacted by this source category. EPA expects that those who live nearest to sources that are impacted by this rule will benefit the most from the rule.

Commenter Name: Janice E. Nolen

Commenter Affiliation: American Lung Association

Document Control Number: EPA-HQ-OAR-2002-0058-3679-A2

Comment Excerpt Number: 7

Comment: Toxic Air Pollution Disproportionately Threatens Many Communities

Communities of color and poorer people also appear to face higher risk, underscoring the need to properly assess this margin of safety. Research indicates that minorities live in greater concentrations both in areas that do not meet federal air quality standards and in areas with above average numbers of air-polluting facilities (NAS, 1999). Both African Americans and Hispanics have been found to be more likely than Caucasians to live in areas with high levels of air toxics (Morello-Frosch and Lopez, 2006).

A study in Maryland found that the risk of cancer related to air toxics was greatest in areas with the largest African American population proportions and lowest among those with the smallest African American population proportions. In addition, the estimated cancer risk decreased for every 10 percent increase in the percentage of Caucasians living in an area. Having a low income also increased the risk among African Americans more so than among Caucasians (Apelberg BJ et al., 2005).

In Houston, Houston is home to one of the world's largest petrochemical complexes, researchers found that the risk of cancer in an area increased along with the proportion of the population that was Hispanic and as measures of social disadvantage increased (Linder et al., 2008).

Response: Because the final rule does not allow emission increases, the EPA has determined that the rule will not have disproportionately high and adverse human health or environmental effects on minority, low-income, or Tribal populations. This statement supports EPA's determination that it has complied with the terms of the Executive Order, which by its terms focuses on adverse impacts. The preamble to the March, 2011 final rule notice (76 FR 15608) discusses environmental justice issues more broadly by focusing on the demographic analysis that shows that that major source boilers are located in areas where minorities' share of the population living within a three-mile buffer is higher than the national average. For these same areas, the percent of the population below the poverty line is also higher than the national average. Because of the emissions reductions mandated by the final rule, EPA believes that the

beneficial effects from the rule will be larger for the average minority and low income American than for all Americans.

16Z. Other Executive Orders

Commenter Name: Susan J. Miller

Commenter Affiliation: Brick Industry Association (BIA)

Document Control Number: EPA-HQ-OAR-2002-0058-3530-A1

Comment Excerpt Number: 1

Comment: This proposal represents an ongoing practice by EPA of establishing a rulemaking without sufficiently reviewing and analyzing available information due to insufficient time and resources being allocated to this important project. The court orders that drive this unreasonable pace are, in part, self-imposed by the EPA. With these incredibly short time periods to review tremendous volumes of information, EPA has not allowed itself the ability to establish the rule based on “careful analysis” as required by Executive Order 13563. This order calls for:

...careful analysis of the likely consequences of regulation, including consideration of underlying science, or alternatives, of costs and benefits, and of simplified, harmonized, and flexible methods for achieving regulatory goals. Under the Executive Order, agencies may not proceed unless the benefits justify the costs (unless the law requires them to do so). In addition, agencies are required to maximize net benefits, to select the least burdensome alternatives, and to consider approaches that promote freedom of choice for the public.

A rush to regulate, without considering all alternatives, would be unacceptable during any economic conditions. However, as our nation continues to struggle to recover, this rush to over-regulate is inexcusable.

Response: We disagree with the commenter that this proposal represents an ongoing practice by EPA of establishing a rulemaking without sufficiently reviewing and analyzing available information due to insufficient time and resources being allocated to this important project. The proposal was due to the reconsideration of the March 2011 final rule initiated because of significant changes made to the final rule, based on *careful analysis of the likely consequences of regulation*, including consideration of underlying science, or alternatives, of costs and benefits, and of simplified, harmonized, and flexible methods for achieving regulatory goals, for which the public did not previously have an opportunity to comment. As was clearly present in the preamble to the March 2011 final rule, the benefits of the regulation clearly justify the costs. In the March 2011 final rule and in the reconsideration proposal, alternatives were developed and analyzed that provide more flexibility in complying with the standards at lower costs without reducing the benefits of the standards. Section 112 of the Clean Air Act mandates the minimum stringency (i.e., MACT floors) in establishing these standards.

Commenter Name: Susan J. Miller

Commenter Affiliation: Brick Industry Association (BIA)

Document Control Number: EPA-HQ-OAR-2002-0058-3530-A1

Comment Excerpt Number: 6

Comment: EPA is not unavoidably committed to one and only one particular approach to determining these standards. Executive Order 13563 dictates that alternatives be considered. EPA has ample discretion to make pragmatic choices that would appropriately balance EPA's responsibility to protect health and the environment with the Agency's (and the US Government's) need to protect and promote the productive capacity of the Nation.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3530-A1, excerpt 1.

Commenter Name: Dean C. DeLorey

Commenter Affiliation: The Amalgamated Sugar Company LLC (TASCO)

Document Control Number: EPA-HQ-OAR-2002-0058-3522-A1

Comment Excerpt Number: 12

Comment: Based on these comments and in accordance with Executive Order 13563, it is requested that the monitoring requirements be substantially reduced to only one source test per 5-year Title V Operating permit period.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3530-A1, excerpt 1, for discussion on Executive Order 13563.

The EPA disagrees with reducing the source testing requirements to be in accordance with Title V permit scheduling. Given the inherent operational and fuel variability of sources subject to the rule, it cannot be guaranteed that the results of one test will remain consistent over a period of five years.

Gas Specification

17A. Appropriateness of Gas Specification

Commenter Name: Dave Copeland, Manager, Air Quality, Corporate Safety and Environmental Services

Commenter Affiliation: Praxair Inc.

Document Control Number: EPA-HQ-OAR-2002-0058-3437-A2

Comment Excerpt Number: 1

Comment: Praxair supports that the rule now contains a mechanism for gases that are not natural gas nor refinery gas to be classified as an "other gas 1 fuel" as spelled out in 40 CFR 63.7521 (f). This is especially important because many of the gases that meet the definition of "other gas 1 fuel" are actually as clean as, if not cleaner than, natural gas/refinery gas. Regulating these types of gases under more stringent requirements than natural gas/refinery gas would unfairly place those gases at a competitive disadvantage and become a hindrance to the productive utilization of these gases as alternative fuels. For example, tail gas produced in hydrogen production process is similar to natural gas but would need to comply with the stringent limits of the "gas 2 fuel" category if not for this option. In a brief summary, tail gas is what is left over in the steam methane reforming (SMR) process used to make hydrogen from natural gas. Natural gas is fed into the SMR along with steam and broken down into methane,

CO, CO₂, nitrogen and hydrogen. The majority of the hydrogen is removed as a product and the remaining material is tail gas, which is fed back to the SMR as a fuel to heat the reaction. This tail gas, which is derived from natural gas, is a clean burning fuel, comparable to natural gas, and it is very appropriate for it to be regulated similar to natural gas rather than as "gas 2 fuel".

Response: The EPA thanks the commenter for their support.

Commenter Name: Elizabeth McMeekin

Commenter Affiliation: PPG Industries, Inc

Document Control Number: EPA-HQ-OAR-2002-0058-3778-A1

Comment Excerpt Number: 6

Comment: PPG supports EPA's proposed revised definition of "Other gas 1 fuel" and the Gas 1 opt-in provision for gases other than natural gas and refinery gas proposed by EPA.

Response: The EPA thanks the commenter for their support.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 24

Comment: Comments on subcategories and definitions associated with subcategorization.

A. The proposed "other gas 1" fuels specification is technically sound and appropriate.

As we pointed out in detail in our comments on the June 4, 2010 proposal, with very limited exceptions, the technical data developed by EPA indicate no HAP emission basis for treating gas 1 and 2 differently and the combined gas category should have only design or work practice standards, since establishing and enforcing an emission limitation for gas-fired BPH is not feasible.

In the preamble to the current proposal, EPA reports its reanalysis essentially reached the same conclusions as the original analysis. Thus, the proposal to treat all gases with mercury levels below 40 micrograms/cubic meter the same as natural gas and refinery gas is technically sound and defensible. All gases combust similarly and thus the fuel mercury level is the only variable that would be an indicator of potential health concerns. Hydrogen sulfide level, which was also included as a criterion in the March 21, 2011 final rule, is not related to the production of HAPs in the combustion process and thus is not a technically appropriate surrogate for HAP emissions. EPA is therefore correct in removing H₂S as an "other gas 1" criterion.

Since gases combust with very low levels of HAP emissions, the overwhelming majority of those emissions are below the level that can be accurately quantified by the available test methods and thus application of a design or work practice standard is appropriate and compliant with section 112(h) of the CAA.

Response: The EPA thanks the commenter for their support.

Commenter Name: Richard Krock
Commenter Affiliation: The Vinyl Institute
Document Control Number: EPA-HQ-OAR-2002-0058-3526-A1
Comment Excerpt Number: 8

Comment: The VI continues to support EPA's proposal to allow other fuels to qualify as Gas 1 fuels subject to work practice standards instead of emission limits.

Response: The EPA thanks the commenter for their support.

Commenter Name: Peter Pagano
Commenter Affiliation: American Iron and Steel Institute (AISI)
Document Control Number: EPA-HQ-OAR-2002-0058-3490-A1
Comment Excerpt Number: 15

Comment: Sections pertaining to the gas 1 fuel specification analysis should be amended to give process gases/coke oven gases a fair opportunity to be considered gas 1 fuels.

Gaseous fuels that qualify as "other gas 1 fuels" are given preferential treatment under the Boiler MACT. Indeed, operators of gas 1 units (*i.e.*, boilers or process heaters that burn fuels considered "clean", namely natural gas, refinery gas, or other gas 1 fuels) have only to comply with work practice standards and regular tune-ups instead of emissions standards. Qualifying as a gas 1 unit is, therefore, an important undertaking for affected sources. While we strongly believe the iron and steel industry should be exempt from the Boiler MACT altogether, we provide the following comments in support of changes to the gas 1 fuel specification analysis to ensure that steel industry process gas have a fair opportunity to be considered for gas 1 treatment.

Response: Sources that are burning coke oven gas or other process gases (other than blast furnace gas or process gases regulated under another subpart of part 63, or part 60, part 61, or part 65) may qualify as a unit designed to burn gas 1 if the gaseous fuels demonstrate compliance with the mercury fuel specification.

Commenter Name: Peter Pagano
Commenter Affiliation: American Iron and Steel Institute (AISI)
Document Control Number: EPA-HQ-OAR-2002-0058-3490-A1
Comment Excerpt Number: 21

Comment: The data suggest that the distinction between gas 1 and gas 2 is not material to the control of HAP emissions. Therefore, EPA should collapse the distinction and allow all gas-fired units to meet the work practices designed to ensure proper combustion. Alternatively, the data support a mercury threshold significantly higher than 40 ug/m³ and, based upon available objective literature, possibly as high as 440 ug/m³.

Response: For a response to the request for all process gases to be given the opportunity to be treated as an other gas 1 fuel, please see comment EPA-HQ-OAR-2002-0058-3490-A1, excerpt 15. EPA disagrees that the distinction between gas 1 and gas 2 should be removed. An analysis was conducted on the gaseous fuel analysis data reported to EPA, the results of which show that

mercury levels in natural gas are approximately equivalent to 40 micrograms per cubic meter. Similar analyses on additional gaseous fuel types show mercury levels much higher than 40 micrograms per cubic meter. Therefore, EPA has retained the gas 1 and gas 2 distinctions in the final rule, as well as the 40 microgram per cubic meter specification required for classification as an other gas 1 fuel. Further, the commenter has provided no information to support the findings required by section 112(h) as a prerequisite to establishing work practice standards in lieu of numeric emissions limits.

Commenter Name: Peter Pagano

Commenter Affiliation: American Iron and Steel Institute (AISI)

Document Control Number: EPA-HQ-OAR-2002-0058-3490-A1

Comment Excerpt Number: 22

Comment: An appropriate and approved testing methodology currently does not exist for process gases. Those methodologies enumerated in Table 6 of the Reconsidered Rule have not been verified as accurate for any fuel other than natural gas. Although the rule allows "equivalent" methodologies be used, EPA must clarify which test methodology is approved for the iron and steel industry to use in testing process gases.

Response: EPA has provided an alternative method for testing other gases at the outlet of the boiler or process heater using traditional stack-test based methods that will work on gases from the iron and steel industry. The affected source can also petition the EPA for alternative methods.

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 41

Comment: In its final rule, EPA now allows some units burning "other process gases" (Gas 2 Units) to substitute work-practice standards for the numeric standards applicable to other such units. 76 Fed. Reg. at 15,639. The units escaping numeric standards need only demonstrate that the gases burned "have levels of H₂S and Hg that are no higher than those found in Gas 1 units." EPA's decision to set work practice standards instead of numeric emission standards for Gas 2 Units is unlawful and arbitrary for all the reasons that its decision to set work practice standards for natural gas units was unlawful and arbitrary. Accordingly, all the comments on the proposed subcategories made in the Comments (Comments at 42-48) are incorporated by reference as if fully stated herein and reiterated with respect to Gas 2 Units.

EPA has not shown and the record does not suggest that the presence of other HAP in the fuel burned necessarily correlates with the presence of H₂S and Hg. Nor has the agency demonstrated that it is not feasible to prescribe or enforce emission standards for Gas 2 units. Indeed, EPA has set numeric standards for Gas 2 units, it just chooses to exempt some of them from compliance by means of allowing them to meet a work practice standard instead. EPA's policy goal of allowing some Gas 2 units to meet work practice standards instead of emission standards does not suffice. Absent a showing that it would be infeasible to prescribe or enforce emission standards for Gas 2 units – a showing that appears nowhere in the record – setting work practice standards for these units is unlawful. And, assuming arguendo that EPA has placed

some rationale for its work practice standards for Gas 2 units somewhere in the record, the agency's decision is nonetheless unlawful and arbitrary and capricious for the reasons given in the 2010 Comments, which are incorporated by reference as if fully stated herein, and above.

Response: As discussed in the March 2011 final rule, the EPA determined that it is not feasible to prescribe numerical emissions standards for Gas 1 units because the application of measurement methodology is not practicable due to technological and economic limitations. Therefore, the EPA is finalizing the work practice standards for Gas 1 units. The measured emissions from these units are routinely below the detection limits of EPA test methods, and, as such, EPA considers it impracticable to reliably measure emissions from these units. Even CO was below the level EPA considers to be a reliable measurement. The case for other pollutants was even more compelling as the majority of measurements are so low as to cast doubt on the true levels of emissions that were measured during the tests. Overall, the available test methods are greatly challenged, to the point of providing results that are questionable for all of the pollutants, when testing natural gas units. Because of these technological limitations that render it impracticable to measure emissions from Gas 1 units, EPA was also unable to establish the actual performance of the best performers as well as sources outside of the top performing 12 percent. The inability to accurately measure emissions from Gas 1 units and the related economic impracticability associated with measuring levels that are so low that even carefully conducted tests do not accurately measure emissions warrant setting a work practice standard under CAA section 112(h).

It was also discussed in the March 2001 final rule preamble that several comments requested that the Gas 1 subcategory be expanded to include gases similar to natural gas and refinery gas. One of the commenter stated that pilot scale and field data studies have concluded that emissions of organic HAP from gaseous fuels are not significantly affected by fuel type. Another commenter submitted combustion properties of refinery gas and petrochemical gas in order to show that they are very similar in composition and should be categorized with natural gas in the Gas 1 category. Based on the information submitted, the EPA determined that to the extent that process gases are comparable to natural gas and refinery gas, combustion of those gases in boilers and process heaters should be subject to the same standards as combustion of natural gas and refinery gas. Boilers that combust other gaseous fuels that have comparable emissions levels to Gas 1 units are similar in class and type to Gas 1 units because they share common design, operation, and emissions characteristics. Therefore, we provided a mechanism by which units that combust gaseous fuels other than natural gas and refinery gas can demonstrate that they are similar to Gas 1 units and therefore be subject to the standards for Gas 1 units. Since the combustion-related pollutants are similar from the various types of gaseous fuel, the fuel related HAP of concern is mercury. Therefore, the EPA believe it is appropriate to base such a demonstration on levels of mercury content in the gases.

We believe that this provision provides the benefit for recovering the waste heat from these offgases. Commenters argue that installation of controls will be prohibitively expensive and thus sources will flare the offgas, instead of burning in a boiler to recovery its energy, and replace it with natural gas.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 133

Comment: EPA should clarify that mixed gas fuels should be evaluated as combusted to determine whether the gaseous fuel meets the Gas 1 mercury criterion. Many industrial sources mix a process gas with natural gas to ensure a high enough heat rate to sustain a stable flame in the combustion unit. The individual gas streams may come from a number of different vessels that are captured and evacuated to a common gas main. It would be impractical to measure each of these individual source streams. That mixed gas is then combusted with natural gas or other process gas fuels to achieve the right Btu value for efficient combustion. EPA should clarify that the mercury concentration used to determine Gas 1 status is based on the mixture of gaseous fuel(s) as they are combusted. Companies should also have the flexibility to either sample the mixed gas before the combustion chamber or, if more convenient, sample the constituent gas streams and calculate the mercury concentration based on an equation that considers the volume of each gas contributed to the combustion chamber. The mercury content of the fuel as it is combusted is the only number relevant to the control of HAP emissions.

Response: The fuel spec was finalized in March as intended, which was based on a test of individual fuel types. Since natural gas and process gases are two different fuel types, the specification finalized by EPA in this rule remains the same as March and ensures that only those gaseous fuels that are as clean as natural gas or refinery gas, via the fuel specification requirements, qualify for work practices. This approach is consistent with the subcategorization in the final rule which does not allow units co-fire natural gas with coal or other fuel types and qualify for a work practice in lieu of numeric emission limits, even if their blended gas stream is consistent with emission levels of natural gas, refinery gas, or other gas 1 fuels. To qualify for a work practice under Section 112(h) of the CAA EPA must conclude that one of the criteria in section 112(h)(2) are met, e.g., that the application of measurement methodology is not practicable due to technological and economic limitations. It is possible to extract other gaseous fuel types for analysis of mercury emissions prior to mixing with natural gas in order to demonstrate that the fuel is comparable to other gas 1 fuel types. Therefore, the EPA has not changed the measurement location of fuel specification in the final rule.

Commenter Name: Peter Pagano

Commenter Affiliation: American Iron and Steel Institute (AISI)

Document Control Number: EPA-HQ-OAR-2002-0058-3490-A1

Comment Excerpt Number: 23

Comment: The definition of "fuel type" must be amended to clarify that process gases mixed with other fuels constitute a single fuel type that should be evaluated "as combusted" to determine its mercury content. Under the current Reconsidered Rule, if both coke oven gas and blast furnace gas fuel a boiler, it is not clear if the operator must separately test the coke oven-gas stream and the blast furnace gas stream or if the combined gas stream entering the boiler must be tested. The rule should clarify that the operator must determine the mercury content of the mixed gas stream to evaluate whether it is a gas 1 fuel. This would also be consistent with the current practice of some iron and steel facilities that employ fuel mixing stations where gaseous fuel (including coke oven gas, blast furnace gas, and natural gas) is mixed to obtain the desired heat value prior to being beneficially reused and combusted in boilers and process heaters. If the

use of process gases determines whether a unit is regulated under the Boiler MACT, how process gases are treated as a fuel type needs to be clarified.

Response: See the response to comment EPA-HQ-OAR2002-0058-3521-A1, excerpt 133. As a result of this determination the EPA has not changed the definition of fuel type for process gases.

Commenter Name: Peter Pagano

Commenter Affiliation: American Iron and Steel Institute (AISI)

Document Control Number: EPA-HQ-OAR-2002-0058-3490-A1

Comment Excerpt Number: 24

Comment: It is the fuel mixture used to fuel the boiler that should be tested and then only at the point of combustion where feasible. As noted above, in iron and steel manufacturing, coke oven gas has multiple purposes. Approximately forty percent of the coke oven gas is sent back to the coke oven as fuel to underfire the ovens. The remainder is distributed elsewhere in the plant wherever fuel or heat is needed. Depending on the type of boiler and its required heat input, different mixtures of fuels are used. Coke oven gas often is supplemented in boilers by natural gas, fuel oil, or blast furnace gas, among others, to optimize heat input and efficient combustion. It is the fuel mixture, not its individual constituents, that determines a boiler's mercury emissions³⁵ Therefore, compliance with a gas 1 specification should be determined by analysis of the fuel mixture as combusted.

[Footnote]

(35) EPA recognizes this fact in its preamble and in its reciprocal output-based regulations corresponding to the input-based (*i.e.*, fuel-based) regulations. *See* 76 Fed. Reg. at 80,607, 80,642.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3490-A1, excerpt 23.

Commenter Name: Peter Pagano

Commenter Affiliation: American Iron and Steel Institute (AISI)

Document Control Number: EPA-HQ-OAR-2002-0058-3490-A1

Comment Excerpt Number: 25

Comment: A process gas fuel mixture should constitute a "fuel type" under section 63.7575. Currently, the Boiler MACT muddies the concept. The preamble states that to demonstrate compliance with mercury emission limits by fuel analysis, the mercury content of the "inlet fuel" must be evaluated. Section 63.7521 (a) states, "For purposes of complying with this section, a fuel gas system that consists of multiple gaseous fuels collected and mixed with each other is considered a single fuel type. We think this is the correct approach for all fuel mixtures and is consistent with the current practice of optimizing the use of fuels based upon their heat content. Nevertheless, both of these provisions lead to the conclusion that the mixed fuel is to be tested, not its individual components. The problem is further complicated, however, when considering the definition of "fuel type," stating that a fuel type is each category of fuels that share a common name or classification, such as bituminous coal, sub-bituminous coal, lignite, anthracite, biomass, and residual oil. This definition should be clarified to ensure that process gases sent to

boilers qualify as a fuel type and to ensure that mixed gaseous fuels are to be tested in the mercury fuel specification analysis as combusted. This can either be accomplished by testing the mixed fuel or by testing two or more contributing gas streams and calculating the as-combusted mercury content. The preamble should contain clarifying language to this point.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3490-A1, excerpt 23.

17B. Subcategories: Specification Used to Determine Gas 1 Category Typical of NG and RFG

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 20

Comment: Streams directly derived from natural gas during its initial processing should be presumed to be "other gas 1".

Natural gas, as described in paragraph 1 of the proposed definition⁵, must be separated from oil, production water, and solids and adjusted to pipeline specifications in production batteries and in natural gas plants. Additionally, intermediate gas streams (i.e., gas streams that are separated from the hydrocarbon/water mixture removed from the ground that do not yet meet the pipeline quality natural gas specifications) are combusted in BPH at the production site or the gas plant. Since natural gas is gas 1 by definition, the gas streams derived directly from natural gas should also be considered gas 1. Thus we recommend that gas streams derived from natural gas at the production site or gas plant be identified as "other gas 1" and that mercury testing be waived.

Specifically, we recommend addition of a paragraph (4) to §63.7521(f) as follows.

(4) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for gas streams directly derived from natural gas at natural gas production sites or natural gas plants. [Footnote 5: (1) A naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or]

Response: We agree with the commenter that any derivatives of natural gas are considered natural gas and are therefore Gas 1. In the final rule §63.7521(f) has been revised to add paragraph 4 as follows.

(4) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for gas streams directly derived from natural gas at natural gas production sites or natural gas plants.

17C. Subcategories: Specification Used to Determine Gas 1 Category (Removal of H2S)

Commenter Name: Felix Mestey, on behalf of Donald R. Schregardus

Commenter Affiliation: Clean Air Act Services Steering Committee, Department of Defense (DoD)

Document Control Number: EPA-HQ-OAR-2002-0058-3427

Comment Excerpt Number: 20

Comment: EPA correctly reexamined the fuel specification and concluded that H2S is not directly related to potential HAP emissions from boilers and process heaters. This proposed change will increase the use of landfill gas, which is often burned off by flaring, as a boiler/process heater fuel. Recent studies at one military installation indicated that landfill gas would not meet the definition of Gas 1 fuel and thus could not be used in existing boilers unless new emission controls for gas 2 fuel units were installed. Including the H2S limit in the definition of other gas 1 fuel in the final rule that was issued on March 21, 2011 made the use of landfill gas at this facility cost-prohibitive.

Recommendation

DoD supports EPA's proposal to eliminate H2S in the definition of other gas 1 fuel and remove related H2S fuel analysis requirements.

Response: The EPA thanks the commenter for their support.

Commenter Name: William C. Herz

Commenter Affiliation: The Fertilizer Institute (TFI)

Document Control Number: EPA-HQ-OAR-2002-0058-3448-A1

Comment Excerpt Number: 6

Comment: In the final *Industrial Boiler Major Source NESHAP* and Proposed Rule, EPA allows entities to demonstrate that process gases are comparable to natural gas and refinery gas and, therefore, that units combusting these gases are subject to the standards for Gas 1 units (referred to as "other gas 1 fuel"). TFI supports this flexibility, generally, and the proposed deletion of a hydrogen sulfide standard in the Proposed Rule, in particular.

As EPA may be aware, a typical ammonia plant uses desulfurized natural gas as both a process gas and a fuel gas. Some of the process gas containing unreacted methane is purged from the ammonia loop section and routed back to the primary reformer where it is burned with incoming desulfurized natural gas as fuel. This purge gas does not contain sulfur because the feed to the reformer is desulfurized natural gas, therefore, there is no need to perform testing to determine the hydrogen sulfide concentration.

Response: The EPA thanks the commenter for their support.

Commenter Name: Angela D. Marconi

Commenter Affiliation: Delaware Solid Waste Authority (DSWA)

Document Control Number: EPA-HQ-OAR-2002-0058-3545-A2

Comment Excerpt Number: 3

Comment: DSWA is pleased that the reconsideration has eliminated the unreasonable hydrogen sulfide (H₂S) limit of 4 ppm that was present in the March 21, 2002 publication. Use of H₂S in this respect is inappropriate because H₂S is neither a hazardous air pollutant (HAP) nor a HAP surrogate. Additionally, imposing this limit on "gas 2" fuels is not warranted because some "gas 1" fuels are not able to meet this requirement (such as some varieties of RG). Although removal of the H₂S limit is helpful, DSWA still recommends classifying LFG as a "gas I".

Response: The EPA thanks the commenter for their support.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 131

Comment: We support the elimination of H₂S as a criterion for the "clean gas" Gas 1 fuel subcategory.

Response: The EPA thanks the commenter for their support.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 10

Comment: Alternatively, if EPA does not qualify landfill gas as Gas 1, CIBO supports the mechanism for a unit to demonstrate its fuel specifications enable it to qualify for Gas 1 treatment. CIBO supports the removal of the H₂S fuel specification from this demonstration mechanism because H₂S is not related to potential hazardous air pollutants that will be emitted from combusting gaseous fuels. 76 FR at 80,609.

Response: The EPA thanks the commenter for their support.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 27

Comment: CIBO supports the EPA's proposal to drop H₂S fuel specifications, for the purpose of regulating a source under Gas 1 standards as opposed to Gas 2 standards, from the proposed Reconsideration Rule. 76 Fed. Reg. 80,609. In its Petition for Reconsideration, CIBO stated that "[s]ince H₂S . . . has limited relevance to HAP emissions other than partial conversion to SO₂, its selection as a Gas 2 to Gas 1 qualifier seems to be arbitrary." In its Reconsideration Rule, EPA agreed that "the key contaminant for demonstration of comparability from a HAP perspective is Hg and that the H₂S fuel specification that was finalized does not provide a direct

indication of potential HAP from combustion of gaseous fuel. Accordingly, the EPA is proposing a fuel specification based only on the Hg level in the gaseous fuel . . ." 76 Fed. Reg. 80,609 (2012 Reconsideration Rule). CIBO supports this proposal.

Response: The EPA thanks the commenter for their support.

Commenter Name: Edward W. Repa

Commenter Affiliation: National Solid Wastes Management Association (NSWMA)

Document Control Number: EPA-HQ-OAR-2002-0058-3539-A1

Comment Excerpt Number: 1

Comment: The proposed boiler reconsideration rule establishes a fuel specification such that LFG can qualify as a Gas 1 fuel. According to the preamble of the proposed rule, EPA states that:

- Mercury (Hg) is the key contaminant from a hazardous air pollutants (HAP) perspective; and
 - Hydrogen sulfide (H₂S) does not provide a direct indication of HAP.[\[1\]](#)
 - The Landfill Institute agrees with EPA that H₂S is not an indicator of HAP because it is based on sweetened pipeline-quality natural gas (NG). A review of H₂S and Hg concentrations is provided in Table 2 [See submittal for Table 2].Based on the data in Table 2, H₂S concentrations in refinery gas (RG), a Gas 1 fuel, are greater than those found in LFG. EPA should not hold LFG to a higher standard than RG that ranges to 450,000 ppmv. Further, EPA did not demonstrate that a correlation exists between H₂S and HAP.
-
- [\[1\]](#)76 FR 247, page 80609

Response: The EPA thanks the commenter for their support.

Commenter Name: Edward W. Repa

Commenter Affiliation: National Solid Wastes Management Association (NSWMA)

Document Control Number: EPA-HQ-OAR-2002-0058-3539-A1

Comment Excerpt Number: 2

Comment: The proposed boiler reconsideration rule establishes a fuel specification such that LFG can qualify as a Gas 1 fuel. According to the preamble of the proposed rule, EPA states that:

1. Mercury (Hg) is the key contaminant from a hazardous air pollutants (HAP) perspective; and
2. Hydrogen sulfide (H₂S) does not provide a direct indication of HAP.⁵

The Landfill Institute agrees with EPA that H₂S is not an indicator of HAP because it is based on sweetened pipeline-quality natural gas (NG). A review of H₂

S and Hg concentrations is provided in Table 2. [See Table 2]

Based on the data in Table 2, H₂S concentrations in refinery gas (RG), a Gas 1 fuel, are greater than those found in LFG. EPA should not hold LFG to a higher standard than RG that ranges to 450,000 ppmv. Further, EPA did not demonstrate that a correlation exists between H₂S and HAP. [footnote 5] 76 FR 247, pg 80609

Response: The EPA thanks the commenter for their support.

Commenter Name: Holly R. Hart

Commenter Affiliation: United Steel Workers (USW)

Document Control Number: EPA-HQ-OAR-2002-0058-3498-A1

Comment Excerpt Number: 4

Comment: USW supports EPA's proposal as described at page 80609 to substitute mercury (Hg) for hydrogen sulfide (H₂S) as the appropriate fuel specification for determining if a gas boiler qualifies as a boiler eligible for work practice standards (Gas 1) or not (Gas 2). USW agree with EPA that H₂S levels do not provide a reliable indication of the levels of hazardous air pollutants (HAP) in the gas.

Response: The EPA thanks the commenter for their support.

Commenter Name: Barry Christensen

Commenter Affiliation: Occidental Chemical Corporation (OCC)

Document Control Number: EPA-HQ-OAR-2002-0058-3477-A1

Comment Excerpt Number: 5

Comment: OCC supports the proposed removal of hydrogen sulfide from the fuel gas specification standard. The rationale provided by EPA in the proposed rule supports the approach that mercury is the primary HAP of concern that requires measurement in gaseous fuels. Hydrogen sulfide levels do not necessarily indicate the presence of other HAPS. Therefore, no additional fuel gas limitations are needed.

Response: The EPA thanks the commenter for their support.

Commenter Name: Russell A. Wozniak

Commenter Affiliation: The Dow Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3449-A1

Comment Excerpt Number: 4

Comment: Dow supports EPA's removal of the fuel specification for hydrogen sulfide since the concentration of hydrogen sulfide in a fuel does not provide a direct indication of potential HAP from combustion of gaseous fuel.

As stated in more detail during our August, 2010 comments on the June, 2010 proposed rule, this proposed definition promotes energy efficiency and allows owner/operators to use clean off-gas streams as fuel which enhances energy efficiency and minimizes air emissions at larger integrated chemical manufacturing sites.

Response: The EPA thanks the commenter for their support.

Commenter Name: Timothy Serie

Commenter Affiliation: American Coatings Association (ACA)

Document Control Number: EPA-HQ-OAR-2002-0058-3502-A1

Comment Excerpt Number: 6

Comment: ACA generally supports the following proposed changes in the Boiler MACT rule:

Proposed fuel specification based only on the Hg level in the gaseous fuel, and not hydrogen sulfide

Response: The EPA thanks the commenter for their support.

Commenter Name: Richard Krock

Commenter Affiliation: The Vinyl Institute

Document Control Number: EPA-HQ-OAR-2002-0058-3526-A1

Comment Excerpt Number: 9

Comment: The VI also supports EPA's decision to remove hydrogen sulfide testing from the fuel gas specification standard. Hydrogen sulfide levels do not necessarily indicate the presence of other HAPs, particularly mercury, which EPA has identified as the primary HAP of concern. Testing for hydrogen sulfide would provide little or no reduction in emission levels.

Response: The EPA thanks the commenter for their support.

Commenter Name: Jessica Bridges

Commenter Affiliation: United States Clean Heat & Power Association (USCHPA)

Document Control Number: EPA-HQ-OAR-2002-0058-3501-A1

Comment Excerpt Number: 4

Comment: With respect to the inclusion of a gaseous fuel specification based only on Hg level in the gaseous fuel EPA is correct in realizing that emissions data for natural gas-fired units show the overwhelming majority of emissions to be below the level that can be quantified by available test methods and in applying that understanding to units combusting other gases with contaminant levels similar to natural gas.

Response: The EPA thanks the commenter for their support.

Commenter Name: Kerry Kelly

Commenter Affiliation: Waste Management (WM)

Document Control Number: EPA-HQ-OAR-2002-0058-3681-A2

Comment Excerpt Number: 12

Comment: Although EPA has created a fuel specification for "other Gas 1 fuels" by which LFG and other gases may qualify for Gas 1 regulatory treatment, as proposed in the Boiler MACT Reconsideration Rule, the fuel specification does not provide a viable avenue by which LFG

combustion in industrial boilers would be relieved of the regulatory burdens associated with unnecessarily stringent emission limits, sampling and testing. While problems exist with the fuel specification as proposed, WM commends the Agency and supports its proposed removal of the inappropriate hydrogen sulfide (H₂S) limit from the Gas 1 fuel specification. In the preamble to the proposed Boiler MACT Reconsideration Rule, EPA explains that:

“EPA has reexamined the fuel specification and agrees that the key contaminant for demonstration of comparability from a HAP perspective is Hg and that the H₂S fuel specification that was finalized does not provide a direct indication of potential HAP from combustion of gaseous fuel. Accordingly, the EPA is proposing a fuel specification based only on the Hg level in the gaseous fuel, and that level is the same level that the EPA included in the March 2011 final rule.”

Waste Management agrees with the Agency’s conclusion that use of an H₂S limit is not an appropriate indicator of potential HAP emissions. As discussed above, WM contracted with CH2M Hill to conduct a comparison of the emissions properties of boilers firing LFG as fuel to those of boilers firing Gas 1 fuels, and to examine the publicly available information to compare LFG to Gas 1 fuels, specifically natural gas and refinery gas. [See submittal for report in Attachment 3] In this report, CH2M Hill noted that EPA based its fuel specification in the March 21, 2011 rule on sweetened, pipeline-quality natural gas. However, refinery gas, the other named Gas 1 fuel, typically contains much higher levels of H₂S than the Gas 1 fuel specification in that rule. CH2M Hill evaluation found that the H₂S concentrations in refinery gas can range from 0 to 450,000 ppm. Based on this data evaluation, WM asserted that LFG should not be held to a higher H₂S standard than refinery gas for qualification as a Gas 1 fuel. We also commented that as H₂S is not a HAP, nor a HAP precursor, nor a surrogate for HAP emissions, it is therefore an inappropriate limit to use in a demonstration of comparability for HAP emissions. While we commend EPA for correcting its Gas 1 fuel specification related to the H₂S limit, we continue to believe that the Boiler Reconsideration Rule, as proposed, creates a significant disincentive to using LFG as an alternative, renewable fuel. Our primary concern with the fuel specification is that despite the proposed correction to remove the H₂S limit from use as a demonstration of comparability, the Gas 1 fuel specification requirements are still unworkable and burdensome. The requirements preclude its use as a viable mechanism for boiler owner/operators or fuel suppliers to demonstrate fuel comparability with the two designated Gas 1 fuels.

Response: The EPA thanks the commenter for their support of the removal of the H₂S limit from the gas 1 fuel specification. The EPA disagrees that the remaining aspects of the gas 1 fuel specification are unworkable and burdensome or that the rule creates a disincentive for the combustion of landfill gas. If landfill gas can meet the Hg fuel specification, it can qualify as other Gas 1 in the same manner as other gaseous fuels.

17D. Subcategories: Specification Used to Determine Gas 1 Category (Rationale for Hg and Hg Level Selected)

Commenter Name: Peter Pagano

Commenter Affiliation: American Iron and Steel Institute (AISI)

Document Control Number: EPA-HQ-OAR-2002-0058-3490-A1

Comment Excerpt Number: 18

Comment: The Gas 1 fuel mercury specification analysis should be amended.

To demonstrate that a fuel qualifies as another gas 1 fuel, an operator must test "a single fuel sample for each fuel type" and verify it contains less than 40 ug/m³. We question this analysis in three key areas: (1) the mercury concentration limit of 40 ug/m³ for other gas 1 fuels, (2) the concept of a "fuel type," and (3) sampling requirements.

First, we question the basis by which EPA established the 40 ug/m³ concentration limit for clean fuels and suggest that a higher threshold be used. The Boiler MACT touts natural gas as the preeminent clean fuel and uses its pollutant concentrations as benchmarks for determining whether other fuels similarly qualify. While AISI does not question that natural gas is a clean fuel and, in fact, supports the work practice standards for natural gas-fired units, EPA appears to have inappropriately derived the 40 ug/m³ concentration from a letter dated January 2011 appearing in the docket.³⁰ The letter details a 40 ug/m³ mercury content in natural gas from a quantity supplied by "Calgon Carbon Corporation", who is a supplier of mercury control technology. The Calgon material cited in the letter in fact was company literature. This information does not qualify as an objective or scientific data source to characterize the level of mercury in U.S. natural gas supplies, nor do we think that Calgon intended it to be used for those purposes. Moreover, while mercury can and is commonly removed from natural gas supplies, that is not always the case. In reality, not all natural gas even meets the 40 ug/m³ limit.

[Footnote]

(30) Comment submitted by James Santory, Director, Environmental Health and Safety, Calgon Carbon Corporation, EPA-HQ-OAR-2002-0058-2956. *See also* EPA's Response to Public Comment's on EPA's National Emission Standards for Hazardous Air Pollutants for Major Source Industrial Commercial Institutional Boilers and Process Heaters, EPA-HQ-OAR-2002-0058-3289, at 288.

Response: The EPA disagrees that the source of the 40 microgram per cubic meter mercury fuel specification limit is not objective or scientific. While we agree that HAP concentrations in gaseous fuels can and do fluctuate, we believe that the 40 microgram per cubic meter limit is appropriate. Uncontrolled mercury emissions data provided for natural gas combustion show, when converted back to a fuel concentration using a Method 19 fuel factor, that all of the natural gas combusted was below the 40 microgram per cubic meter threshold for mercury content.

Commenter Name: Peter Pagano

Commenter Affiliation: American Iron and Steel Institute (AISI)

Document Control Number: EPA-HQ-OAR-2002-0058-3490-A1

Comment Excerpt Number: 19

Comment: Scientific data on this subject actually suggests that a much higher content threshold is appropriate. Mercury content in natural gas varies depending on where it is captured.³¹ For example, mercury concentrations for Midwest and Eastern U.S. pipeline natural gas can be as high as 100 and 440 ug/m³, respectively, well above the specification in the definition. Another study in the literature lists the mercury concentrations for Midwestern and Eastern U.S. pipeline natural gas ranging between 1 to

100 ug/m³ and 19 to 440 ug/m³, respectively³²

[Footnotes]

(31) Carnell, Peter J.H., et al., Mercury Matters, reprinted from Hydrocarbon Engineering 2005. (Permission of the publisher requested and we will supplement the docket when received.)

(32) Carnell, Peter J.H., et al., Mercury Matters, reprinted from Hydrocarbon Engineering 2005. (Permission of the publisher requested and we will supplement the docket when received.)

Response: See the response to comment EPA-HQ-OAR-2002-0058-3490-A1, excerpt 18.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 10

Comment: EPA should examine the 40 µg/m³ mercury criteria for process gases to qualify as Gas 1. As stated in the detailed comments being submitted by the American Coke and Coal Chemicals Institute (ACCCI), there are several regions where natural gas has a higher mercury content than 40 µg/m³. The threshold neither represents natural gas mercury content nor constitutes a specification for the natural gas industry.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3490-A1, excerpt 18.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 132

Comment: We question using a mercury content of 40 µg/m³ as the criterion to determine Gas 1 eligibility. The mercury specification should properly reflect all available data indicating the highest measured concentrations in natural gas and refinery gas, the two gaseous fuel types that EPA has declared "clean gas." Data provided by ACCCI and AISI in their comments indicate that mercury concentrations are found in natural gas well above the 40 µg/m³ threshold that EPA uses in the rule to define "clean gas."

Response: See the response to comment EPA-HQ-OAR-2002-0058-3490-A1, excerpt 18.

Commenter Name: Shannon S. Broome

Commenter Affiliation: Auto Industry Forum (AIF)

Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1

Comment Excerpt Number: 20

Comment: *If EPA Persists in Listing Landfill Gas in the Gas 2 Category and Subjecting It to the Demonstration Mechanism, EPA Should Still Make a Categorical Determination to Automatically Classify Landfill Gas as an "Other Gas 1 Fuel."*

As noted above, LFG is equivalent to Gas 1 fuels NG and RG in the relevant emission measures, abundant data show Hg levels for LFG as consistently, substantially below the “other Gas 1 fuel” specification limit for Hg, and compelling policy reasons support classifying LFG as a Gas 1 fuel. If, however, EPA fails to list LFG in that category and, instead, persists in listing LFG as a Gas 2 that can qualify for the Gas 1 category only through the demonstration mechanism, then EPA should make a categorical determination that LFG qualifies as an “other Gas 1 fuel.” AIF, therefore, recommends EPA modify § 63.7521(f) as follows:

To demonstrate that a gaseous fuel other than natural gas or refinery gas qualifies as an other gas 1 fuel, as defined in § 63.7575, you must conduct a fuel specification analysis for mercury . . . except as specified in paragraph (f)(1) through (3) of this section.

(1) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for natural gas, or refinery gas or landfill gas.

Boiler MACT Reconsideration Proposal, 76 Fed. Reg. at 80,633 (strikethrough reflecting suggested deletions; underline reflecting suggested additions).

Response: EPA disagrees that landfill gas should be exempted from the gas specification. EPA does not discount that several data sources suggest that landfill gas has similar HAP characteristics and emission profiles as natural gas and refinery gas. However, emissions data reported to EPA suggest that landfill gas has the potential to exhibit higher HAP emissions than natural gas or refinery gas. EPA believes that the mercury limit of 40 micrograms per cubic meter is an appropriate measure of HAP concentrations in gaseous fuels, and that the combustion of fuels with a higher mercury content exhibits the significant potential for environmental harm. Thus, EPA has not provided an exemption from the fuel specification for landfill gas in the final rule.

Commenter Name: Kerry Kelly

Commenter Affiliation: Waste Management (WM)

Document Control Number: EPA-HQ-OAR-2002-0058-3681-A2

Comment Excerpt Number: 10

Comment: If EPA fails to list LFG in the Gas 1 category despite the abundant data showing that LFG mercury levels are substantially below the Gas 1 fuel specification limit for mercury, then EPA should provide a categorical determination for LFG. The categorical determination that LFG qualifies as an other gas 1 fuel should be granted based on available published data, including EPA’s own reports, that shows LFG meets the other Gas 1 fuel specification limit of 40µg/m³. We therefore recommend §63.7521(f) be modified as follows:

§63.7521(f) To demonstrate that a gaseous fuel ~~other than natural gas or refinery gas~~ qualifies as an other gas 1 fuel,.....except as specified in paragraph (f)(1) through (3) of this section.

(1) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for natural gas ~~or~~, refinery gas or landfill gas.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3512-A1, excerpt 20.

Commenter Name: Shannon S. Broome
Commenter Affiliation: Auto Industry Forum (AIF)
Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1
Comment Excerpt Number: 13

Comment: In the reconsideration proposal, EPA proposes to eliminate the H₂S specification but would retain the Hg specification for a fuel to qualify in the Gas 1 category. As explained in detail below, AIF supports the elimination of the H₂S specification but believes that retention of the Hg specification, at least as to LFG, is unnecessary and inappropriate based upon the technical information before the Agency and that the proposal discourages the beneficial use of LFG (a gas formerly flared at the landfill) in boilers and process heaters. Instead, the proposed rule will create barriers to using LFG, a renewable fuel, and lead companies that have sought to put LFG to beneficial use to move back toward exclusive use of NG. This will result in combustion of neglected LFG by the landfills that will:

- increase emissions to the environment overall since the landfill gas must still be burned or flared,
- waste a valuable fuel source further depleting NG reserves, and
- run counter to EPA's policies and programs for encouraging the beneficial use of LFG.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3512-A1, excerpt 20.

Commenter Name: Edward W. Repa
Commenter Affiliation: National Solid Wastes Management Association (NSWMA)
Document Control Number: EPA-HQ-OAR-2002-0058-3539-A1
Comment Excerpt Number: 3

Comment: NSWMA does not agree with EPA that Hg is a better indicator of HAP. From Table 2, the concentrations of Hg in both NG and RG are greater than LFG. As with H₂S, EPA is holding LFG to a high standard than a Gas 1 fuel and the agency has not demonstrated that a correlation exists between Hg and HAP

Response: See the response to comment EPA-HQ-OAR-2002-0058-3512-A1, excerpt 20.

Commenter Name: William C. Herz
Commenter Affiliation: The Fertilizer Institute (TFI)
Document Control Number: EPA-HQ-OAR-2002-0058-3448-A1
Comment Excerpt Number: 7

Comment: The purge gas should not require testing to determine the mercury concentration and a comparison to the 40 micrograms/cubic meters limit in the regulations since the purge gas stream is merely unreacted natural gas purged from the ammonia loop section. Utilization of this purge gas not only makes the plant more efficient but also reduces the release of pollutants from these systems.

Response: Only gases other than natural gas, refinery gas, and gaseous fuels subject to another subpart of part 63 are required to test to determine mercury concentration. The purge gas would not be required to be tested if it is unreacted natural gas.

Commenter Name: Paul G. Page

Commenter Affiliation: AK Steel Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3457-A2

Comment Excerpt Number: 7

Comment: It is not clear from the definition of "other gas 1 fuel" how this considerable variability and complication in fuel mixture, sampling point, and mercury concentration should be addressed. If EPA does not exempt "process gases that otherwise would be flared" directly from the definition of "waste heat boiler," then AK Steel believes the Agency needs to significantly revise the definition of "other gas 1 fuels" to incorporate additional protocols on the methods to demonstrate compliance under such variable circumstances.

Response: EPA has revised the definition of waste heat boilers, but that edit does not incorporate waste heat boilers using gases that would otherwise be flared. Refer to the chapter of this response to comment document under the Legal/Applicability section on waste heat boilers. For a discussion of other methods added to demonstrate compliance with the other gas 1 fuel specification, refer to comment EPA-HQ-OAR-2002-0058-3490-A1, excerpt 22 under the chapter Appropriateness of Gas Specification.

Commenter Name: Peter Pagano

Commenter Affiliation: American Iron and Steel Institute (AISI)

Document Control Number: EPA-HQ-OAR-2002-0058-3490-A1

Comment Excerpt Number: 20

Comment: Moreover, natural gas companies do not have to comply with quality specifications themselves, including mercury specifications. EPA's own documents reveal that mercury removal in many natural gas plants is optional and depends on the amount of mercury in feeds, whether aluminum heat exchangers are utilized, and whether downstream customers have mercury specifications³³ According to publicly available information from the Federal Energy Regulation Commission ("FERC"), there also are no mercury limits or thresholds imposed on natural gas in FERC gas tariffs. The absence of a mercury specification for natural gas and the aforementioned data mean that the proposed mercury limit of 40 ug/m³ either should be eliminated or increased substantially. The threshold neither represents natural gas mercury content nor constitutes a specification for the natural gas industry.

[Footnote]

(33) Mercury in Petroleum and Natural Gas: Estimation of Emissions from Production, Processing, and Combustion, EPA/600/R-01-066 (September 2001) [See DCN EPA-HQ-OAR-2002-0058-3490-A2 for attachment]

Response: The EPA disagrees a lack of mercury specification data for natural gas should lead to the limit being eliminated or increased. Units burning natural gas are not subject to the gaseous

fuel specification, and thus the lack of a precedent for mercury content in natural gas does not apply to this rule. For discussion on requests for the 40 microgram per cubic meter limit to be increased, please see the response to comment EPA-HQ-OAR-2002-0058-3490-A1, excerpt 18.

17E. Subcategories: Specification Used to Determine Gas 1 Category (Other Parameters)

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 32

Comment: ACC members support the Gas 1 opt-in provision for gases other than natural gas and refinery gas proposed by EPA. We agree with EPA's proposed definition of "other gas 1 fuel" and the mercury content criteria. Additionally, ACC believes that additional criteria such as Btu content and organic HAP content are not needed or appropriate since some process gases have lower Btu content than natural gas (e.g., hydrogen), or higher organic HAP than natural gas (e.g., some chemical process gases), but are still clean burning (i.e., result in HAP emissions that are not feasible to measure).

Response: The EPA thanks the commenter for their support.

Commenter Name: Elizabeth McMeekin

Commenter Affiliation: PPG Industries, Inc

Document Control Number: EPA-HQ-OAR-2002-0058-3778-A1

Comment Excerpt Number: 7

Comment: PPG agrees with EPA's proposed mercury content criteria, and we believe that additional criteria such as Btu content and organic HAP content are not appropriate. Some process *gases*, such as hydrogen, may have lower Btu content than natural *gas*, or higher organic HAP than natural *gas*, but are still as clean burning as natural gas.

Response: The EPA thanks the commenter for their support.

Commenter Name: Shannon S. Broome

Commenter Affiliation: Auto Industry Forum (AIF)

Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1

Comment Excerpt Number: 14

Comment: AIF urges EPA to revisit its proposed specifications. Moreover, AIF urges the Agency to recognize the importance of minimizing liability for users of LFG and not impose certification requirements on content of the gas that are not within the control of the certifying entity.

Response: EPA disagrees that the rule provides a disincentive to combust landfill gas. If a source combusts landfill gas, and the fuel demonstrates compliance with the mercury gas

specification limit, the source is classified as a unit designed to combust other gas 1 fuels and is subject to the same work practices as units burning natural gas or refinery gas. EPA believes this creates incentives for units to switch to the combustion of gaseous fuels, including landfill gas, that likely meet the mercury gas specification limit.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 8

Comment: As set forth in its Petition for Reconsideration and Comments on the Proposed Rule, there is no rational reason to not provide similar regulatory treatment for gaseous fuels that have similar constituents and emissions impacts as natural gas. In response to EPA's question whether additional parameters should be included in the Gas 1 fuel specification, CIBO urges that no additional criteria should be included because there is no rational basis for these to be added.

Response: The EPA agrees with the commenter, and no additional parameters have been added to the gas specification.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 12

Comment: To the extent that landfill gas is categorized as neither Gas 1 nor given a categorical exemption from the fuel specification mechanism, EPA should change the fuel specification mechanism and allow for alternative testing and certification measures. In the proposed Reconsideration Rule, a Gas 2 unit can secure Gas 1 treatment by: (1) certifying that the fuel will "never" exceed the Hg specification of 40 mm/m³, or (2) conduct monthly testing of the fuel. *Id.* at 80,641-42. Rather than certifying that a fuel will "never" exceed the Hg specification, a unit should have to certify that, based on available data, it is reasonably unlikely that the fuel will not exceed the Hg specification. Additionally, if a unit elects the testing option, the frequency of testing should be reduced if the unit's prior tests show consistent compliance with fuel specifications. Additionally, EPA should expand the allowable test methods listed in the *Boiler MACT Reconsideration Proposal*, 76 Fed. Reg. at 80,666 (Table 6) to include the allowable methods used to gather the Hg data that affected facilities supplied to EPA in response to the Section 114 requests (EPA Methods 29, 30A, or 30B at 40 CFR part 60).

Response: The EPA has revised the rule language to provide for a tiered testing frequency, based on the results of the initial fuel specification results. Refer to 63.7540(c) for this revised testing frequency. This should remove the concerns of the commenter regarding certification of never exceeding the fuel specification. Regarding allowing additional test methods, refer to comment EPA-HQ-OAR-2002-0058-3490-A1, excerpt 22 under the chapter Appropriateness of Gas Specification.

17Z. Other Gas Specification Comments

Commenter Name: Shannon S. Broome

Commenter Affiliation: Auto Industry Forum (AIF)

Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1

Comment Excerpt Number: 25

Comment: The compliance benchmark for Hg in gas fuels other than NG or RG is flatly inconsistent with compliance approaches used to demonstrate compliance with emission limits and work practice standards. It unfairly subjects all other gaseous fuels other than NG or RG to a fuel specification that the Gas 1 fuels are not even required to address in the most cursory manner. It suggests that even one aberrant or anomalous fuel measurement, would function as sufficient basis for failing to demonstrate the Hg specification is met and subjecting the unit to Gas 2 limits. This conflicts with the compliance demonstration methods presented elsewhere in the same reconsideration proposal, including in § 63.7520(e), in § 63.7522, and in § 63.7530. All of these fuel analysis-based compliance methods involve performing some type of statistical data analysis of multiple fuel samples. Moreover, the certification option is inconsistent with the very definition of "other Gas 1 fuel," which states that such fuel "*does not* exceed the maximum concentration of 40 micrograms/cubic meters of mercury." *Boiler MACT Reconsideration Proposal*, 76 Fed. Reg. at 80,653. The definition does not discuss future events, nor should it, and, therefore, it is unreasonable based on this definition to impose a certification as to future conditions as a compliance tool.

For these reasons, there should be no certification option. At a minimum, EPA should amend the compliance method for demonstrations that gaseous fuels other than NG or RG qualify as a Gas 1 fuel to ensure that it is consistent with these other approaches. As a corollary, to the extent EPA retains a certification option, EPA should provide that companies can make the certification based on an initial fuel specification analysis that shows Hg content below the specification level or based on contractual terms with the landfill that require the LFG to be below the level. Otherwise, companies that are unwilling to use LFG if they would be subject to Gas 2 limits may simply opt not to continue combusting LFG. And EPA must ensure comparison to a single maximum value reported among a group of samples does not determine compliance (or more importantly, non-compliance).

Response: The EPA has revised the rule language to provide for a tiered testing frequency, based on the results of the initial fuel specification results. Refer to 63.7540(c) for this revised testing frequency and 63.7530(g) for the certification revisions. This should remove the concerns of the commenter regarding certification of never exceeding the fuel specification.

Commenter Name: Kerry Kelly

Commenter Affiliation: Waste Management (WM)

Document Control Number: EPA-HQ-OAR-2002-0058-3681-A2

Comment Excerpt Number: 14

Comment: The "never exceed" specification for mercury in gas fuels other than natural gas or refinery gas is more stringent than typical compliance demonstration methods such as for emission limits and work practice standards. For example, we are not aware of any other

circumstance in which EPA has required a facility to certify to future compliance with work practice standards, or to certify the contents of future emissions tests or analyses. Likewise, the certification requirement included in the proposed Boiler MACT Reconsideration Rule is inconsistent with the very definition of "other gas 1 fuel", which states that such fuel "does not exceed the maximum concentration of 40 micrograms/cubic meters of mercury." (76 FR 80653). The definition does not discuss future events (nor should it), and therefore it is unreasonable based on this definition to impose a requirement to certify future conditions as a compliance tool in this case. Such requirement unfairly subjects all gaseous fuels other than natural gas or refinery gas to a fuel specification standard that these two Gas 1 fuels are not required to even address in the most cursory manner.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3512-A1, excerpt 25.

Commenter Name: Shannon S. Broome

Commenter Affiliation: Auto Industry Forum (AIF)

Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1

Comment Excerpt Number: 24

Comment: Even if the Hg constituents in the fuel consistently test far below the specification, the absolute formulation of the certification could be read in the future to potentially impose liability on the source not only for gas that exceeds the specification but also for a "false certification," should the highly unlikely circumstance outside of the representative's control arise in which the constituents of a purchased fuel like LFG exceed the regulatory specification. Further, it is simply substantively unreasonable to impose the term "never" as a qualification to limit testing obligations in this case, since certifications under Section 112 and Title V are intended to be based on information and belief formed after reasonable inquiry. *See, e.g.*, 40 C.F.R. § 70.5(c).

Response: See the response to comment EPA-HQ-OAR-2002-0058-3512-A1, excerpt 25.

Commenter Name: Shannon S. Broome

Commenter Affiliation: Auto Industry Forum (AIF)

Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1

Comment Excerpt Number: 26

Comment: *AIF's Comments on the Monthly Testing Option*

If a fuel's gas constituents "could vary above the [fuel] specification," then, under the proposed regulations, monthly testing is required. *See id.* EPA should revise this option for several reasons. First, EPA fails to provide any explanation as to why other options beyond monthly sampling as to each individual facility could not reliably demonstrate compliance with the Hg fuel specification limit. As conveyed in the discussion of the categorical determination approach outlined above, EPA could allow for the performance of a one-time, fuel specification compliance study, performed following applicable EPA sampling guidance, for fuel types like LFG, *i.e.*, for use of the fuel across all facilities. By including a representative number of facilities and collecting numerous samples, such a study could reliably characterize the variability of Hg concentrations so as to obviate the need for monthly testing. With respect to

LFG, as discussed elsewhere in these comments, the numerous published studies that have evaluated Hg in LFG provide a sufficient database for demonstrating compliance with the Hg fuel specification limit. However, as the reconsideration proposal does not address this type of study, AIF recommends that EPA revise it to incorporate this approach as an option for classification as an "other Gas 1 fuel."

Response: EPA disagrees with the commenter about developing a facility-specific representative testing value. Process and combustion conditions can vary between facilities and therefore EPA has determined that each facility should conduct the test. However, EPA has adjusted the testing frequency for the fuel specification for facilities that conduct an initial fuel specification and demonstrate their emissions are at or below the specification as discussed in Refer to 63.7540(c) of the final rule.

Commenter Name: John V. Corra, Director

Commenter Affiliation: State of Wyoming Department of Environmental Quality

Document Control Number: EPA-HQ-OAR-2002-0058-3435-A1

Comment Excerpt Number: 5

Comment: EPA should afford companies the option of using the results of a representative fuel analysis from another similar affected facility to demonstrate that the fuel qualifies as "other gas 1" fuel in accordance with § 63.7521, and other applicable subparts. Similar to relying on the fuel provider to demonstrate fuel quality, if a company can demonstrate that the fuel used at a second facility is comparable to that of previously analyzed fuel at a first affected facility, then the company should not have to test the fuel at the second facility. Implementing this practice could reduce testing requirements, while maintaining the regulatory intent for companies to address fuel quality.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3512-A1, excerpt 26.

Commenter Name: Russell A. Wozniak

Commenter Affiliation: The Dow Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3449-A1

Comment Excerpt Number: 11

Comment: Dow supports EPA's proposed rule revisions of 40 CFR 63.7521(g)(2)(iii) which rightfully addresses the situation where multiple boilers and process heaters are fueled by a common fuel stream. Sampling to determine compliance with the mercury fuel specification can be done at a common point of gas distribution.

Response: The EPA thanks the commenter for their support.

Commenter Name: Russell A. Wozniak

Commenter Affiliation: The Dow Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3449-A1

Comment Excerpt Number: 13

Comment: EPA should modify the proposed rule at 40 CFR 63.7521(h) regarding the number of fuel samples to provide more flexibility.

EPA's proposed rule states that: "You must obtain a single fuel sample for each fuel type according to the sampling procedures listed in Table 6 for fuel specification of gaseous fuels."

EPA should modify the final rule to allow the owner/operator to obtain multiple samples of gas for mercury analysis to provide a reliable average when determining whether or not a gas fuel stream will meet the specification of 40 micrograms per cubic meter. In many cases, our approach to sampling and analysis is that samples are taken either in duplicate or triplicate. EPA should allow the option of averaging the results of multiple samples in order to determine the concentration of mercury present in the fuel gas stream(s). The following changes are recommended to 40 CFR 63.7521(h):

You must obtain, at a minimum, a single fuel sample for each fuel type according to the sampling procedures listed in Table 6 for fuel specification of gaseous fuels. The owner/operator may obtain more than one fuel sample according to the sampling procedures listed in Table 6 for fuel specification of gaseous fuels and may average the results of all fuel samples when determining the mercury concentration of a fuel.

Response: EPA disagrees with allowing an average Hg level be the basis for comparison to the other gas 1 fuel specification. The intent of the fuel specification was to have a level at which gases comparable with natural gas and refinery gas mercury contents could qualify for a work practice standard in lieu of emission limits. This comparison must be consistent and should not cover a fuel that is sometimes containing mercury levels higher than the 40 microgram/m³ specification. If this standard is not consistently met the fuel does not qualify as an other gas 1 fuel type. The EPA did allow for sources to voluntarily continue to collect mercury data in 63.7540(c)(4) for a subsequent 12 month period in order to allow a source to switch from the unit designed to burn gas 2 subcategory to the unit designed to burn other gas 1 fuel subcategory as long as the mercury data supports this switch in subcategories.

Commenter Name: Russell A. Wozniak

Commenter Affiliation: The Dow Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3449-A1

Comment Excerpt Number: 14

Comment: If the owner/operator is subject to monthly sampling requirements for mercury to demonstrate that the criteria for other gas 1 fuels is met, EPA should clarify how an individual sample > 40 micrograms/cubic meter will be handled.

Proposed 40 CFR 63.7530(g) requires monthly testing for mercury content if the gas constituents could vary above the specification. However, EPA's rule does not address situations where one or two samples perhaps over the course of a year may have a mercury content > 40 micrograms per cubic meter. In order to avoid a situation where one or two "high" sample results occur over the course of a year, EPA should allow the Dow Chemical Comments Page 7 Docket EPA-HQ-OAR-2002-0058

owner/operator to calculate an annual average (based on the monthly sample results from a 12 month period) to determine whether or not the off-gas fuel is meeting the mercury specification of less than 40 micrograms per cubic meter.

Response: EPA has revised the language at 63.7540(c) to explain what steps should be taken if the initial gaseous fuel specification shows mercury levels in exceedance of the 40 microgram per cubic meter limit. Each affected unit burning this gaseous fuel is not a part of the unit designed to burn gas 1 subcategory, and must be in compliance with the emission and operating limits for the appropriate subcategory. These sources may elect to conduct additional monthly sampling while complying with the emission and operating limits to demonstrate that the gaseous fuel qualifies as an other gas 1 fuel. If 12 consecutive monthly fuel samples are at or below the 40 microgram per cubic meter limit, each affected unit can elect to switch back into the unit designed to burn gas 1 subcategory. Monthly fuel samples must continue to be conducted, and the unit may elect to remain in the unit designed to burn gas 1 subcategory until a fuel sample exceeds the 40 microgram per cubic meter limit.

For a response to the request for multiple fuel samples and an annual average be included in the gaseous fuel specification, please see comment EPA-HQ-OAR-2002-0058-3449-A1, excerpt 13.

Commenter Name: Kerry Kelly

Commenter Affiliation: Waste Management (WM)

Document Control Number: EPA-HQ-OAR-2002-0058-3681-A2

Comment Excerpt Number: 21

Comment: Per §63.7521(h), you must obtain a single fuel sample for each fuel type. Table 6 requires the owner/operator or fuel supplier to measure mercury concentration in the fuel sample (emphasis added) and convert to units of ug/m³. The proposed fuel specification demonstration apparently ensures that even one aberrant or anomalous fuel measurement, even if it is not valid, would be sufficient basis for failing to demonstrate the mercury fuel specification is met. This sampling requirement is inconsistent with compliance methods presented elsewhere in the proposed Boiler MACT Reconsideration Rule, specifically in §63.7530, which directs that the arithmetic average mercury concentration in each fuel type should be used and also provides an equation for calculating a 90 percent upper confidence limit fuel concentration from sample data (referred to in the rule as the “90th percentile confidence level”⁵). The fuel analysis based compliance method involves performing some type of statistical data analysis of multiple fuel samples. At a minimum, the approach used to demonstrate that a gaseous fuel qualifies as an other Gas 1 fuel should be consistent with compliance methods provided elsewhere in the proposed Boiler MACT Reconsideration Rule and standard EPA statistical guidance (e.g., EPA’s 2006 report, Data Quality Assessment: Statistical Methods for Practitioners. EPA QA/G-9S. EPA/240/B-06/003). We recommend that the proposed Boiler MACT reconsideration Rule be amended to ensure that compliance will not be determined based on one sample or by comparison to a single maximum value reported among a group of samples.

[Footnote]

(5) The equation provided for calculating a “90th percentile confidence level” to compare to emission limits (Eq. 10 at 76 FR 80641) does not appear to reflect EPA statistical guidance, for

example, as provided in EPA's 2006 report, Data Quality Assessment: Statistical Methods for Practitioners. EPA QA/G-9S. EPA/240/B-06/003.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3449-A1, excerpt 13.

Commenter Name: Kerry Kelly

Commenter Affiliation: Waste Management (WM)

Document Control Number: EPA-HQ-OAR-2002-0058-3681-A2

Comment Excerpt Number: 18

Comment: WM recommends the EPA modify the certification requirements and testing frequency in §63.7530(g) as follows: (g) If you elect to demonstrate....If the mercury constituents in the gaseous fuels ~~will never~~ do not and are not reasonably expected to exceed the specification included in the definition, you will include a signed certification with the Notification of Compliance Status that the initial fuel specification test meets the gas specification outlined in the definition of other gas 1 fuels. The Notification of Compliance Status may include other relevant data or measurements that supports the certification that the mercury constituents are not reasonably expected to exceed the specifications ~~If your gas constituents could vary above the specification, you will~~ If your initial fuel specification test does not meet the gas specification outlined in the definition of other gas 1 fuels or would otherwise be reasonably expected to vary above the specification, then you must follow Gas 2 subcategory requirements or you may conduct monthly testing according to the procedures in §63.7521(f) through (i) and §63.7540(c) and maintain records of the results of the testing as outlined in §63.7555(g). Where 12 consecutive monthly samples demonstrate that the fuel meets the specification for mercury for the other gas 1 subcategory, you may decrease fuel specification testing frequency to annually.

Response: The language at 63.7530(g) has been revised. All units burning gaseous fuels other than natural gas refinery gas that may qualify as an other gas 1 fuel must conduct the initial fuel specification analysis if classification in the gas 1 category is desired. For fuels for which the initial specification analysis demonstrates compliance with the mercury specification limit, the requirement for a signed Notification of Compliance Status was retained.

The testing frequency at 63.7540(c) has been modified since the December 23, 2011 proposed rule to include the following provision:

- (1) If the mercury concentration resulting from the initial fuel specification analysis is equal to or less than half of the 40 microgram per cubic meter limit, no further sampling is required.
- (2) If the initial test shows that the mercury concentration is between half and 75% of the 40 microgram per cubic meter limit, you must conduct semi-annual sampling. If any semi-annual sample exceeds 75% of the limit, you must return to monthly sampling until 12 consecutive months of sampling show mercury levels at or below 75% of the limit.
- (3) If the initial test shows that the mercury concentration is greater than 75% of the limit, you must conduct monthly sampling. If 12 consecutive months show mercury levels below 75% of the limit, you may switch to semi-annual fuel sampling.

Commenter Name: Kerry Kelly
Commenter Affiliation: Waste Management (WM)
Document Control Number: EPA-HQ-OAR-2002-0058-3681-A2
Comment Excerpt Number: 19

Comment: We recommend the EPA modify the certification requirements and testing frequency in §63.7540(c) as follows: (c) If you elected to demonstrate that the unit meets the specification for mercury for the other gas 1 subcategory and you cannot submit a signed certification under § 63.753045(g) because the constituents ~~could exceed~~ exceeded the specification, you must follow Gas 2 subcategory requirements or conduct monthly fuel specification testing of the gaseous fuels, according to the procedures in § 63.7521(f) through (i). Where 12 consecutive monthly samples demonstrate that the fuel meets the specification for mercury for the other gas 1 subcategory, you may decrease fuel specification testing frequency to annually.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3681-A2, excerpt 18.

Commenter Name: Peter Pagano
Commenter Affiliation: American Iron and Steel Institute (AISI)
Document Control Number: EPA-HQ-OAR-2002-0058-3490-A1
Comment Excerpt Number: 26

Comment: EPA proposes that a gas 1 fuel can be certified based on process knowledge confirmed by a single fuel sample mercury analysis. Absent that certification, monthly fuel samples are required to verify gas 1 eligibility. This is impractical because a single sample with elevated mercury could recategorize a source from gas 1 to gas 2 and impose new generic emission limits that cannot immediately be met. The specification analysis should instead be based on two or more fuel samples taken and analyzed prior to the calendar year(s)³⁸ for which the certification would be effective. The average mercury content over those samples would be used to determine if the fuel meets the gas 1 mercury specification. Averaging over multiple fuel samples mitigates the effect of uncharacteristic spikes in the mercury content of process gases. If all valid data are below the specification, the fuel should be deemed certified gas 1 and no further fuel samples should be required unless the fuel type has changed. Otherwise, the fuel specification mercury sampling and testing would occur again in advance of the next period for which the gas 1 certification would be effective. This process offers sources some notice and time to plan if they determine that a process gas can no longer meet the gas 1 fuel specification.

[Footnote]

(38) AISI encourages EPA to extend this period of gas 1 certification to facilitate longer term planning in the industry. EPA has used a three year period to assess eligibility thresholds that could subject a unit to significantly different regulatory obligations. *See* 40 CFR 72.6(b)(4)(i) (rendering a cogeneration unit subject to the Acid Rain program if it contributes more than 113 of its output capacity to the grid for sale averaged over any three calendar years.)

Response: For discussion on changes to the sampling frequency for the gaseous fuel specification, please see comment EPA-HQ-OAR-2002-0058-3681-A2, excerpt 18. For

discussion on requests for additional fuel samples to be included and averaged as a part of the fuel specification, please see comment EPA-HQ-OAR-2002-0058-3449-A1, excerpt 13.

Commenter Name: Kerry Kelly

Commenter Affiliation: Waste Management (WM)

Document Control Number: EPA-HQ-OAR-2002-0058-3681-A2

Comment Excerpt Number: 16

Comment: The Boiler MACT Rule should not preclude subsequent testing to demonstrate compliance with the fuel specification where the results of the initial fuel specification demonstration did not meet the gas specification outlined in the definition of other gas 1 fuels. In this case, a subsequent initial test followed by periodic testing, such as monthly sampling, to validate initial fuel specification demonstration results could be required. The proposed Boiler MACT Reconsideration Rule states that if “12 consecutive monthly fuel analyses demonstrate compliance, you may request decreased fuel analysis frequency by applying to the EPA.” (76 FR 80631). We recommend the Agency also include a reduced testing frequency, such as annually or bi-annually where 12 consecutive monthly samples demonstrate that the fuel meets the gas specification outlined in the definition of other gas 1 fuels.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3681-A1, excerpt 18.

Commenter Name: Shannon S. Broome

Commenter Affiliation: Auto Industry Forum (AIF)

Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1

Comment Excerpt Number: 27

Comment: In the alternative, EPA fails to provide any explanation as to why it does not allow, at the facility-specific level, an equivalent, one-time fuel specification analysis, performed following applicable EPA sampling guidance, for demonstrating compliance with the Hg fuel specification limit. The absence of such an option is inconsistent with other compliance requirements in the proposed reconsideration rule, including performance stack tests annually and tune-ups annually, biennially or every five years. Consistent with those compliance requirements, in the alternative, EPA should amend the reconsideration rule to allow each facility to qualify a fuel as an "other Gas 1 fuel," if the initial fuel specification analysis demonstrates Hg concentration a certain percentage below the specified limit.

Response: The testing frequency at 63.7540(c) has been revised. If the initial gaseous fuel specification analysis shows a mercury concentration at or below half of the 40 microgram per cubic meter limit, no further fuel sampling is required. EPA believes that, at mercury levels this low, it is highly unlikely that the mercury concentration of the fuel will ever fluctuate above the 40 microgram per cubic meter limit, and thus further testing is not necessary. For more discussion on changes to the sampling frequency for the gaseous fuel specification, please see comment EPA-HQ-OAR-2002-0058-3681-A2, excerpt 18.

Commenter Name: Shannon S. Broome

Commenter Affiliation: Auto Industry Forum (AIF)

Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1

Comment Excerpt Number: 21

Comment: *To the Extent that Landfill Gas (or Any Gaseous Fuel) May Qualify as Gas 1 Only Through the “Other Gas 1 Fuel” Specification, EPA Should Finalize the Proposed Elimination of the H2S from the Specification Because H2S is Not Directly Related to Potential HAP from the Combustion of Gaseous Fuel.*

As noted above, EPA proposes to revise the fuel specification analyses requirements for the demonstration mechanism. *See id.* at 80,609, 80,641. Specifically, EPA reexamined the fuel specification and concluded that (1) the H2S fuel specification from the final rule does not provide a direct indication of potential HAP from combustion of gaseous fuel and (2) the key contaminant for demonstration of comparability from a HAP perspective is Hg. *See id.* Upon reexamination, then, EPA proposes to eliminate the H2S fuel specification and use an “other Gas 1 fuel” specification based only on an Hg level in the gaseous fuel of 40 µg/m³, *i.e.*, the same level as EPA included in the final rule of March 21, 2011. *See id.* Under this proposal, LFG (and other gaseous fuels besides NG and RG) still would initially fall into the Gas 2 fuel category but could now qualify as an “other Gas 1 fuel” with merely a demonstration of not exceeding the previously published Hg limit of 40 µg/m³. *Boiler MACT*, 76 Fed. Reg. at 15,639.

As articulated above, AIF urges EPA to automatically classify LFG as a Gas 1. If, however, EPA retains the demonstration mechanism and still classifies LFG (and/or other gaseous fuels) in the Gas 2 category, AIF supports the proposed elimination of H2S from the fuel specification, *i.e.*, EPA’s proposed “other Gas 1 fuel” specification based solely on a Hg concentration of 40 µg/m³. AIF concurs with EPA that the H2S fuel specification from the final rule does not provide a direct indication of potential HAP from the combustion of gaseous fuel. Moreover, as stated in AIF’s prior comments, the prior formulation of the demonstration mechanism arbitrarily and capriciously required LFG to meet an H2S emission limit of 4 ppmv or less for classification as a Gas 1 even while the regulations allowed RG emissions of up to 162 H2S and still automatically treated RG as a Gas 1. If EPA elects to retain the demonstration mechanism as the method for LFG (and other gaseous fuels) to attain “other Gas 1 fuel” classification, AIF, therefore, supports the proposed elimination of the H2S fuel specification.

Response: The EPA thanks the commenter for their support of the removal of the H2S limit from the gaseous fuel specification analysis. The decision to exclude the H2S limit has been retained in the final rule.

The EPA disagrees that landfill gas should automatically qualify as a gas 1 fuel. Emissions data reported to EPA show that uncontrolled mercury emissions from landfill gas, when converted back to a gaseous fuel concentration, can fluctuate above and below the 40 microgram per cubic meter limit. For this reason, landfill gas has not been defined as a gas 1 fuel, and units combusting landfill gas may elect to demonstrate that the fuel qualifies as an other gas 1 fuel by conducting the fuel specification analysis.

Commenter Name: Shannon S. Broome

Commenter Affiliation: Auto Industry Forum (AIF)

Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1

Comment Excerpt Number: 28

Comment: In the alternative, EPA fails to provide any explanation as to why it does not allow a gradual, performance-based reduction in the monthly testing frequency as facilities obtain successive positive results as to a particular fuel. As an example, if a source reports less than a certain percentage of the Hg fuel specification for several consecutive months (*e.g.*, less than 80% of the 40 µg/m³ level), the regulations could provide for an automatic reduction in testing frequency to every other month; then, after a certain duration of continued positive testing, the frequency would decrease to every six months, and so on. There is no rational basis to indefinitely require monthly testing when a fuel regularly tests well below the Hg fuel specification for qualifying as an "other Gas 1 fuel." EPA has utilized such compliance flexibility in other contexts. *See, e.g.*, 40 C.F.R. § 63.1161 (NESHAP for Steel Pickling, Subpart CCC; EPA allows the permitting authority to approve an alternative schedule for performance testing that allows testing less frequently than annually); 40 C.F.R. § 63.1543(e) (NESHAP for Primary Lead Smelting, Subpart TTT; EPA allows less-frequent testing when facilities demonstrate consistent compliance with the standards); 40 C.F.R. § 265.1057(c)(1) (Subpart BB of the Resource Conservation and Recovery Act ("RCRA") Regulations, valves in gas/vapor service; EPA permits sources to monitor valves for leaks less frequently if a leak is not detected for two successive months and allows sources to skip quarterly leak detection periods if a low percentage of valves are leaking). Consistent with those regimes, in the alternative, EPA should finalize a gradual, performance-based reduction in the monthly testing frequency for the "other Gas 1 fuel" specification as facilities obtain successive positive results as to a particular fuel.¹⁷

[Footnote 17: Moreover, to the extent EPA retains any form of the monthly testing option, it should more clearly articulate to facilities how the monthly testing option works, *e.g.*, if a facility tests below the "other Gas 1 fuel" specification level one month but then above the specification level the next month, whether it can, then, test back into the Gas 1 category the succeeding month with a test result below the specification level.]

Response: See the response to comment EPA-HQ-OAR-2002-0058-3681-A1, excerpt 18.

Commenter Name: Shannon S. Broome

Commenter Affiliation: Auto Industry Forum (AIF)

Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1

Comment Excerpt Number: 22

Comment: *As to the "Other Gas 1 Fuel" Specification, EPA Should Amend the Certification Option to Make It More Workable and Amend the Monthly Testing Option to Allow for Additional Flexibility.*

Even with the proposed elimination of H₂S, the "other Gas 1 fuel" specification does not provide a viable avenue for relieving LFG (and other gaseous fuels in the Gas 2 category) of the regulatory burdens associated with unnecessarily stringent emission limits, sampling, and testing.

In its current form, the demonstration mechanism still creates a significant disincentive for companies to purchase and use LFG as a renewable fuel alternative to NG. It provides facilities using fuels in the Gas 2 category and seeking to qualify those fuels for classification in the Gas 1 category with a choice between a certification or monthly testing. Specifically, proposed § 63.7530(g) states:

If you elect to demonstrate that a gaseous fuel meets the specifications of an other gas 1 fuel as defined in §63.7575, you must conduct an initial fuel specification analyses according to §63.7521(f) through (i). If the mercury constituents in the gaseous fuels will *never exceed the specification* included in the definition (40 ug/cm) you will include a signed certification with the Notification of Compliance Status that the initial fuel specification test meets the specification outlined in the definition of other gas 1 fuels. If your gas constituents could vary above the specification, you will conduct *monthly testing* according to the procedures in §63.7521(f)-(i) and §63.7540(c) and maintain records of results of the testing as outlined in §63.7555(g).

Boiler MACT Reconsideration Proposal, 76 Fed. Reg. at 80,641 (emphasis added). As indicated in this proposed regulatory language, the certification option requires the fuel user to sign a certification, based on the results of an initial fuel specification analysis according to § 63.7521(f)-(i), that the gaseous fuel will *never* exceed the regulatory fuel specification. *See id.* The alternative, if the gas constituents in the fuel could vary, is conducting *monthly testing* per § 63.7521(f)-(i) and keeping the requisite, corresponding records. *See id.* EPA proposes retaining these provisions in the same form as promulgated in the final rule of March 21, 2011, however, with the elimination of the H₂S fuel specification, affected sources now would only need to make a certification or conduct the monthly testing as to the Hg constituents. *See id.*

AIF objects to the language of the certification requirement as unworkably absolute and inconsistent with other compliance approaches in the Boiler MACT, and to the alternative of monthly testing as onerous and, as applied to LFG, not supported by the consistently low concentrations of Hg from available analyses.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3681-A1, excerpt 18.

Commenter Name: Shannon S. Broome

Commenter Affiliation: Auto Industry Forum (AIF)

Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1

Comment Excerpt Number: 23

Comment: *AIF's Comments on the Certification Option*

The absoluteness of the certification option EPA imposes – a promise that LFG will *never* exceed the Hg specification – is problematic because it asks the *user* of the gas to certify what will occur in the future based on actions the user does not control. A facility's responsible official may well conclude that he or she cannot guarantee the future given the absolute language, even though there is no reasonable expectation that Hg content will exceed the specification level. EPA should revise the language and/or clarify it to be clear that initial tests below the 40 µg/m³ level are sufficient to make the certification (or some percentage of that level, *e.g.*, if the initial test is less than 80% of the 40 µg/m³ level, a facility is not required to do

testing). Such an approach would provide an objective criterion for facilities to know whether or not they are required to conduct periodic testing.

Response: See the response to comment EPA-HQ-OAR-2002-0058-3681-A1, excerpt 18 for discussion on changes to the sampling frequency for the gaseous fuel specification. For discussion on landfill gas and the request for it to be classified as a gas 1 fuel, please see comment EPA-HQ-OAR-2002-0058-3512-A1, excerpt 21.

Commenter Name: Kerry Kelly

Commenter Affiliation: Waste Management (WM)

Document Control Number: EPA-HQ-OAR-2002-0058-3681-A2

Comment Excerpt Number: 13

Comment: The certification requirements in proposed §63.7530(g) state: “If you elect to demonstrate that a gaseous fuel meets the specifications of an other gas 1 fuel as defined in §63.7575, you must conduct an initial fuel specification analyses according to §63.7521(f) through (i). If the mercury constituents in the gaseous fuels will never exceed the specification included in the definition (40 ug/cm) you will include a signed certification with the Notification of Compliance Status that the initial fuel specification test meets the specification outlined in the definition of other gas 1 fuels. If your gas constituents could vary above the specification, you will conduct monthly testing according to the procedures in §63.7521(f)-(i) and §63.7540(c) and maintain records of results of the testing as outlined in §63.7555(g).” This provision would appear to require a certification that LFG “will never exceed the specification limit for mercury.” Such a certification, relating to unknown future conditions, is overly burdensome, impractical and unworkable. A facility designated representative cannot sign such a certification without taking an undue legal/fiduciary risk, even for a highly unlikely circumstance that is out of the representative’s control. Such certification is inconsistent with RCRA and Clean Air Act NSPS, NESHAP and Title V operating permit certification requirements, which allow for certifications to be based on all credible evidence, generator knowledge, and which provide for certifications based on generator or operator knowledge, information, belief. While it can be demonstrated that a gaseous fuel consistently meets the mercury specification through all currently available data sets (as shown above with respect to LFG), it is unnecessary and impossible to demonstrate that a gaseous fuel will never exceed such specification in the future, especially where the content of future analyses and data sets cannot be known.

Response: For discussion on changes to the sampling frequency for the gaseous fuel specification, please see comment EPA-HQ-OAR-2002-0058-3681-A2, excerpt 18. For discussion on landfill gas and the request for it to be classified as a gas 1 fuel, please see comment EPA-HQ-OAR-2002-0058-3512-A1, excerpt 21.

Commenter Name: Angela D. Marconi

Commenter Affiliation: Delaware Solid Waste Authority (DSWA)

Document Control Number: EPA-HQ-OAR-2002-0058-3545-A2

Comment Excerpt Number: 2

Comment: If the final rule does not allow LFG to be a "gas 1" fuel, changes to the "other gas 1" requirements are necessary. The reconsideration allows LFG to be categorized as "other gas 1" if

it is certified that the LFG "will never exceed the specification limit for mercury". DSWA finds it unlikely that any entity would execute a certification with such rigid language. We suggest that the language should be changed to reasonably account for the possibility of factors beyond the entity's control. This could be accounted for via an engineering report that would explain the remote likelihood of an increase in the mercury content of LFG.

The alternative to certification is monthly lab analysis. The required frequency of testing is onerous. An annual or semiannual test is sufficient to determine mercury levels present in gas.

Response: For discussion on changes to the sampling frequency for the gaseous fuel specification, please see comment EPA-HQ-OAR-2002-0058-3681-A2, excerpt 18. For discussion on landfill gas and the request for it to be classified as a gas 1 fuel, please see comment EPA-HQ-OAR-2002-0058-3512-A1, excerpt 21.

Commenter Name: Kerry Kelly

Commenter Affiliation: Waste Management (WM)

Document Control Number: EPA-HQ-OAR-2002-0058-3681-A2

Comment Excerpt Number: 15

Comment: The only alternative to this onerous certification requirement provided in the proposed Boiler MACT Reconsideration Rule is monthly testing of gaseous fuels to demonstrate compliance with the gas specification. This testing requirement is not supported by the consistently low levels of mercury from all available LFG analyses. Accordingly, in the case of LFG, the Initial Fuel Specification Analysis is sufficient to demonstrate Other Gas 1 status. Section 63.7530(g) states that you will conduct monthly testing if your gas constituents could vary above the specification. In addition, §63.7540(c) requires monthly fuel specification testing be conducted at each facility if a signed certification stating mercury fuel specification limit will never be exceeded cannot be submitted. As discussed above, it is unreasonable and inconsistent with other Federal Rules to require such certification. The requirement to conduct monthly testing is also unreasonable and inconsistent with other compliance requirements in the proposed Boiler MACT Reconsideration Rule (i.e., annual performance stack test, annual or biennial tune-ups). The proposed Boiler MACT Reconsideration Rule should allow, at the facility-specific level, a one-time certification, performed following applicable EPA sampling guidance, rather than monthly monitoring to demonstrate compliance with the mercury fuel specification limit.

Response: For discussion on changes to the sampling frequency for the gaseous fuel specification, please see comment EPA-HQ-OAR-2002-0058-3681-A2, excerpt 18. For discussion on landfill gas and the request for it to be classified as a gas 1 fuel, please see comment EPA-HQ-OAR-2002-0058-3512-A1, excerpt 21.

Commenter Name: Kerry Kelly

Commenter Affiliation: Waste Management (WM)

Document Control Number: EPA-HQ-OAR-2002-0058-3681-A2

Comment Excerpt Number: 11

Comment: To the extent that LFG or any gaseous fuel may only qualify for Gas 1 categorization through a fuel specification, WM requests that EPA revise the specification to

ensure that it is established in a manner that will include LFG that is managed in accordance with existing CAA requirements as discussed above. For example, the Landfill MACT requires that LFG be routed to a treatment system that processes the gas for subsequent sale or use as fuel; this requirement would be an appropriate and adequate specification for demonstrating that LFG may be combusted as a Gas 1 fuel.

Response: For discussion on the request for landfill gas to automatically be classified as a gas 1 fuel, please see comment EPA-HQ-OAR-2002-0058-3512-A1, excerpt 21. Comments pertaining to correlating this rule with other MACT rules are outside the scope of this comment response document.

Commenter Name: Kerry Kelly

Commenter Affiliation: Waste Management (WM)

Document Control Number: EPA-HQ-OAR-2002-0058-3681-A2

Comment Excerpt Number: 20

Comment: We recommend the EPA modify the certification requirements and testing frequency in §63.7555(g) as follows: (g) If you elected to demonstrate that the unit meets the specification for mercury for the other gas 1 subcategory and you cannot submit a signed certification under § 63.753045(g) because the constituents ~~could exceed~~ exceeded the specification, you must follow Gas 2 subcategory requirements or maintain monthly and/or annual records of the calculations and results of the fuel specification for mercury in Table 6.

This approach is consistent other NESHAP requirements such as 40 CFR Part 63, Subpart N (40 cfr 63.344); Subpart GGG (see 40 CFR 63.1250). See also 40 CFR 261.10 (use of generator knowledge to certify to regulatory characteristics of materials)

Response: The EPA has updated the recordkeeping requirements for the sources demonstrating compliance with the fuel specification. The edits do not exactly reflect the requests of the commenter, but EPA agrees that the wording needed to be revised to be consistent with the frequency of the fuel sampling required under 63.7540(c).

Other Petitioner Issues Not Granted Reconsideration

112A. Allow Health-Based Compliance Alternatives for HCl, Mn, and Acid Gases [DENIED PETITIONER ISSUE]

Commenter Name: Randall D. Quintrell

Commenter Affiliation: Georgia Paper & Forest Products Association

Document Control Number: EPA-HQ-OAR-2002-0058-3451-A1

Comment Excerpt Number: 2

Comment: Allowing a health-based option, particularly for HCl, would benefit solid fuel units among the industrial boiler fleet. Under the current MACT proposal, those facilities would be required to install pollution control equipment at an estimated average capital cost of \$1 million per affected unit and incur additional annual operating costs of \$2 million per unit, *without*

realizing a commensurate improvement in public health protection. The health-based emissions limitations established in the 2004 MACT rule were developed under rigorous standards that protect public health with an ample margin of safety. EPA can and should set health-based standards that are clearly and unequivocally allowed by the Clean Air Act.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Peter Pagano

Commenter Affiliation: American Iron and Steel Institute (AISI)

Document Control Number: EPA-HQ-OAR-2002-0058-3490-A1

Comment Excerpt Number: 37

Comment: Health-based compliance options should be available based on site-specific demonstrations.

EPA has the discretion to include a health-based compliance option for hydrochloric acid and manganese because they are threshold pollutants for which scientists have determined a level below which adverse health effects are not observed. EPA included a health-based compliance option in the original Boiler MACT rule, but has excluded it in the proposed rule. Given the significant cost of this rule and burden on U.S. businesses, EPA should exercise all of its options to provide site-specific flexibility. To the extent a facility can prove that its emissions, when considered with the emissions in the area, do not produce concentrations at or across their fence line in excess of the health-based threshold for HCL or manganese, they should be able to avoid the unnecessary costs of controlling those emissions.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Roger Martella

Commenter Affiliation: National Alliance of Forest Owners (NAFO)

Document Control Number: EPA-HQ-OAR-2002-0058-3519-A1

Comment Excerpt Number: 9

Comment: First, we urge EPA to adopt health-based compliance alternatives for HCl and manganese under section 112(d)(4) of the Clean Air Act in order to provide environmental health benefits while avoiding extreme costs to the industry. Biomass contains very small amounts of HCl and the proposed numerical standards will require expensive technological adjustments that provide very little benefit to public health or the environment. In addition, EPA has long recognized that manganese is emitted from many facilities in amounts that do not expose anyone in surrounding population to concentrations above the established health thresholds and therefore the emissions do not pose a significant risk to the surrounding population.²⁹ Providing an alternative health-based approach will ensure that high compliance costs are not imposed on the industry unless commensurate health benefits are provided.

[Footnote 29: 69 Fed. Reg. 55,218, 55,241 (Sept. 13, 2004).]

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Stephen E. Woock

Commenter Affiliation: Weyerhaeuser Company

Document Control Number: EPA-HQ-OAR-2002-0058-3523-A1

Comment Excerpt Number: 12

Comment: Weyerhaeuser continues to urge EPA to reverse its position and provide health-based compliance alternatives for HCl and for manganese. When the original Boiler MACT was promulgated in 2004, it included "Health Based Compliance Alternatives" (HBCA) as emissions limitations for HCl and manganese. Weyerhaeuser found these alternatives would have been a significant cost reduction factor that still met the CAA goals of reducing health and environmental risk. At that time we intended to employ the HBCA for one or both of the target HAPs at about one-third of our then-existing portfolio of mills. We refer EPA to our discussion of this approach in our comments on the June 2010 proposed rule (see docket ID EPA-HQ-OAR-2002-0058-2797) and incorporate those comments by reference.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Douglas A. McWilliams

Commenter Affiliation: American Municipal Power

Document Control Number: EPA-HQ-OAR-2002-0058-3685-A2

Comment Excerpt Number: 1

Comment: EPA Should Adopt a Health-Based Emission Limit for HCl

EPA has long recognized its authority to adopt health-based emission limits (11 HBELs") pursuant to CAA § 112(d)(4). Section 112(d)(4) authorizes EPA to consider, "[w]ith respect to pollutants for which a health threshold has been established . . . such threshold level, with an ample margin of safety, when establishing emission standards under [112(d)]." Congress's intent in including section 112(d)(4) was to avoid setting HAP emission limits that go well beyond what is needed to protect the public. In formulating this section of the CAA, Congress recognized that 11 [f]or some pollutants a MACT emissions limitation may be far more stringent than is necessary to protect public health and the environment."4 As a result, Congress included section 112(d)(4) as an alternative standard setting mechanism for HAPs "where health thresholds are well-established . . . and the pollutant presents no risk of other adverse health effects, including cancer... ."5

In the 2004 Boiler MACT rule, EPA determined that the MACT floor limits established for HCl were in some cases more stringent than necessary to protect public health, and established an HBEL as a compliance alternative for solid fuel-fired boilers. The HCl limits EPA found more stringent than necessary were 0.02 lb/mmBtu and 0.07 lb/mmBtu for new and existing units, respectively.6

Since that time, EPA has continued to impose even more stringent HCI limits on solid fuel-fired boilers. In the March 2011 Rule, EPA imposed an HCI limit of 0.035 lb/mmBtu on existing units. Despite recommendations and numerous comments from the regulated community (including the Small Business Advisory Review Panel), EPA declined to include an HBEL in that rule. In the Proposed Rule, EPA has proposed an HCI limit that is *more than 30% more stringent* than the March 2011 rule and *almost 70% more stringent* than the 2004 rule for solid fuel-fired units. These significantly more stringent limits only bolster support for EPA's initial 2004 determination and the recommendations of the Small Business Advisory Review Panel ("SBA Review Panel"). EPA has articulated no explanation for abandoning its 2004 approach or ignoring the advice of the SBA Panel. A final rule that does not include an HBEL option would be unsupportable.

[Footnote 4: S. REP. NO. 101-228 (1990) at 171.]

[Footnote 5: *!d.*]

[Footnote 6: 69 Fed. Reg. at 55270.]

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Douglas A. McWilliams

Commenter Affiliation: American Municipal Power

Document Control Number: EPA-HQ-OAR-2002-0058-3685-A2

Comment Excerpt Number: 2

Comment: EPA Should Adopt a Health-Based Emission Limit for HCI

EPA has long recognized its authority to adopt health-based emission limits (11 HBELs") pursuant to CAA § 112(d)(4). Section 112(d)(4) authorizes EPA to consider, "[w]ith respect to pollutants for which a health threshold has been established . . . such threshold level, with an ample margin of safety, when establishing emission standards under [112(d)]." Congress's intent in including section 112(d)(4) was to avoid setting HAP emission limits that go well beyond what is needed to protect the public. In formulating this section of the CAA, Congress recognized that 11 [f]or some pollutants a MACT emissions limitation may be far more stringent than is necessary to protect public health and the environment."4 As a result, Congress included section 112(d)(4) as an alternative standard setting mechanism for HAPs "where health thresholds are well-established . . . and the pollutant presents no risk of other adverse health effects, including cancer... ."5

In the 2004 Boiler MACT rule, EPA determined that the MACT floor limits established for HCI were in some cases more stringent than necessary to protect public health, and established an HBEL as a compliance alternative for solid fuel-fired boilers. The HCI limits EPA found more stringent than necessary were 0.02 lb/mmBtu and 0.07 lb/mmBtu for new and existing units, respectively.6

Since that time, EPA has continued to impose even more stringent HCI limits on solid fuel-fired boilers. In the March 2011 Rule, EPA imposed an HCI limit of 0.035 lb/mmBtu on existing

units. Despite recommendations and numerous comments from the regulated community (including the Small Business Advisory Review Panel), EPA declined to include an HBEL in that rule. In the Proposed Rule, EPA has proposed an HCI limit that is *more than 30% more stringent* than the March 2011 rule and *almost 70% more stringent* than the 2004 rule for solid fuel-fired units. These significantly more stringent limits only bolster support for EPA's initial 2004 determination and the recommendations of the Small Business Advisory Review Panel ("SBA Review Panel"). EPA has articulated no explanation for abandoning its 2004 approach or ignoring the advice of the SBA Panel. A final rule that does not include an HBEL option would be unsupportable.

[Footnote 4: S. REP. NO. 101-228 (1990) at 171.]

[Footnote 5: *!d.*]

[Footnote 6: 69 Fed. Reg. at 55270.]

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Douglas A. McWilliams

Commenter Affiliation: American Municipal Power

Document Control Number: EPA-HQ-OAR-2002-0058-3685-A2

Comment Excerpt Number: 4

Comment: Adoption of an HBEL for acid gases would significantly reduce this cost burden for small entities by allowing them to meet emission limitations that are protective of human health and the environment without spending millions on unnecessary control equipment and operating costs. Under both the RFA and the Unfunded Mandates Reform Act ("UMRA"), EPA is obligated to consider the costs of its rules on small government entities and to analyze the costs of alternative regulatory approaches. EPA has not done so. EPA never analyzed the significant costs that might be avoided by offering an HBEL option for HCI, despite the fact that the SBA Review Panel's number one recommendation was adoption of an HBEL.¹¹ Instead, EPA vaguely asserted a lack of information and implementation issues that do not exist. In the final March 2011 rule, EPA cited the "potential environmental impacts and cumulative impacts of acid gases on public health."¹² EPA performed a thorough analysis of the HBEL alternative in 2004, and concluded it could establish an HBEL that was protective of human health and the environment with an ample margin of safety. Furthermore, the 2004 HBEL alternative required each source wishing to use the HBEL to perform a site-specific risk analysis to ensure that the public would be adequately protected.

[Footnote¹¹: EPA properly analyzed the costs savings in 2004, and determined it would save approximately \$2 billion in unnecessary control costs.]

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Douglas A. McWilliams
Commenter Affiliation: American Municipal Power
Document Control Number: EPA-HQ-OAR-2002-0058-3685-A2
Comment Excerpt Number: 5

Comment: EPA further attempted to justify its exclusion of an HBEL option by citing the co-benefits of collateral non-HAP emission reduction that would occur under the technology-based limitation. Specifically, EPA cited reductions in SO₂, non-condensable PM, and other non-HAP acid gases.¹³ The Clean Air Act does not permit EPA to consider non-HAP collateral emission reductions in setting standards. Section 112(d)(2) provides an express list of factors that EPA may consider in setting section 112(d) standards. That list includes "the cost of achieving such emission reduction, and any *non-air quality* health and environmental impacts and energy requirements." (emphasis added). This list does not include consideration of non-HAP air quality benefits, which are likely to be minimal at best. In the coming years, many of these sources will be required to reduce SO₂ and PM emissions because of other regulatory requirements, such as the revised NAAQS standards. It would be unreasonable for EPA to base its refusal to include an HBEL on reductions in pollutants that are already managed by other programs. EPA cannot support its refusal to properly analyze the HBEL option under the RFA and UMRA by citing non-existent "potential" impacts and air quality benefits that are likely to occur with or without the Boiler MACT rule.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Douglas A. McWilliams
Commenter Affiliation: American Municipal Power
Document Control Number: EPA-HQ-OAR-2002-0058-3685-A2
Comment Excerpt Number: 7

Comment: It Would Be Arbitrary for EPA to Disregard Its Prior Adoption of Health-Based Emission Limits

When EPA first promulgated the Boiler MACT rule in 2004, it included HBELs for HCl and manganese. These standards required a site-specific risk assessment to demonstrate that emissions from the site were low enough to protect human health with an ample margin of safety. The standards also required actual emission testing to verify emission rates used in the risk assessment, and required sources to include relevant site parameters such as stack height and fence locations in its Title V operating permit.¹⁴ These standards required accountability, and were more than adequate to protect human health and the environment without forcing struggling small entities to invest millions in unnecessary control equipment. EPA and the Department of Justice vigorously defended these HBELs in the final 2004 rule and in the ensuing litigation. EPA dedicated 17 pages of its brief to explaining why its HBELs complied with the requirements of section 112(d)(4). In that brief, EPA acknowledged making the following determinations: (1) both HCl and manganese have reference concentrations and have not been shown to be carcinogenic, (2) the HBELs provided an ample margin of safety, (3) "health-based standards would not reduce the HAP-related health benefits from the rule because only those

facilities with emissions that did not pose a health risk would qualify for the alternative standards," (4) it is inappropriate to consider potential cumulative risks until the residual risk stage of the NESHAP process, and (5) "the potential collateral benefits of controls were not a proper reason to impose control costs under the HAPs program on facilities with HAP emissions that did not pose a public health risk." EPA argued that each of these positions was reasonable, in accord with the law, and entitled to deference. EPA has offered no explanation for its about-face on this issue.

Although EPA has discretion in setting HBELs, "a reasoned explanation is needed for disregarding facts and circumstances that underlay or were engendered by [a] prior policy." *FCC v. Fox Television Stations, Inc.*, 129 S. Ct. 1800, 1810 (2009). EPA has offered no explanation for its change in position, or even acknowledged its prior defense of HBELs in the 2004 Boiler MACT rule. In particular, the two main arguments EPA relies upon for refusing to establish an HBEL for HCl- the concern over cumulative risks and collateral benefits- are *directly contrary* to the conclusions EPA reached in items (4) and (5) above. EPA's failure to acknowledge its prior determination and failure to explain why it has raised as questions issues that previously were resolved render its decision not to propose HBELs arbitrary and capricious.

[Footnote14: See 69 Fed. Reg. at 55227-28.]

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Heather Parent

Commenter Affiliation: Maine Department of Environmental Protection

Document Control Number: EPA-HQ-OAR-2002-0058-3691-A2

Comment Excerpt Number: 13

Comment: We believe that EPA's proposed standards for hydrochloric acid (HCl) exceed the levels necessary to protect public health and will create an unnecessary compliance burden for affected units. We recommend that EPA apply the provisions of Section 112(d)(4) to the extent possible to establish a more appropriate scheme for HCl emission reductions.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

114A. Definition of Natural Gas Curtailment [DENIED PETITIONER ISSUE]

Commenter Name: Russell A. Wozniak

Commenter Affiliation: The Dow Chemical Company

Document Control Number: EPA-HQ-OAR-2002-0058-3449-A1

Comment Excerpt Number: 31

Comment: EPA should further clarify the definition of "Period of gas curtailment or supply interruption".

The definition of “Period of gas curtailment or supply interruption” should be revised to also incorporate scenarios that are beyond the control of the facility that “restrict” the supply of gas fuels to a site in such a manner that the type of fuel used by some on-site boilers would need to be changed for a short period of time. The proposed definition could be interpreted to mean that the only conditions that would meet this definition are those where the gas supply to the site is completely stopped or halted.

Therefore, EPA should consider adding “or restricted” to the first sentence in the definition as follows:

means a period of time during which the supply of gaseous fuel to an affected facility is halted or restricted for reasons beyond the control of the facility.

In addition, many contractual agreements are possible for supplying gas fuel to a site and EPA should clarify that the use of back-up fuel is allowed under certain situations where the supply of gas fuel is restricted to a site under a purchase contract agreement to the extent that a very high cost or penalty would be involved for continued gas use under certain situations. Thus, the first sentence of the definition could be further amended as follows:

means a period of time during which the supply of gaseous fuel to an affected facility is halted or restricted for reasons beyond the control of the facility or due to the terms of a contractual agreement with a supplier of gas fuel that allows gas curtailment or supply interruption.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Timothy Serie

Commenter Affiliation: American Coatings Association (ACA)

Document Control Number: EPA-HQ-OAR-2002-0058-3502-A1

Comment Excerpt Number: 15

Comment: ACA generally supports the following proposed changes in the Boiler MACT rule:

Revised definition of natural gas curtailment to clarify that a curtailment does not include normal market fluctuations in the price of gas that are not associated with periods of supplier delivery restrictions; however, the term “halted” may be interpreted to interfere with existing contractual obligations and therefore is too restrictive.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 125

Comment: When disparity between overall supply and overall demand threatens the integrity of the pipeline transportation system, interruptible supply contracts are curtailed first generally by

Operational Flow Orders (or similar contractual requirements by another name) issued to users under their supply contract terms. These orders do not generally involve physically blocking the supply pipeline,⁵⁵ but rather an evaluation after the fact of possible non-contractually compliant use during the curtailment period and the institution of a fine or penalty that can be assessed as high as 10 or so times the contract gas sales price. Payment of a penalty due to unauthorized natural gas usage during an Operational Flow Order is regularly not considered an increase in the cost or unit price of natural gas or a surcharge due to market supply/demand fluctuations. The contracts and user requirements are to protect the integrity of the pipeline system and allow its operation in compliance with FERC requirements.

The current definition could be interpreted to mean that if a company contracts for interruptible natural gas supply, where the interruption could either mean the supply is halted by the utility/FERC regulated pipeline or the facility must switch fuels to avoid contractual fines, the use of backup liquid fuel during periods of high residential/critical infrastructure demand would not constitute curtailment unless the utility/FERC-regulated pipeline actually physically halts the entire supply of gas to the facility.

[Footnote 55: More drastic response such as blocking service lines generally is not considered unless more drastic curtailment situations warrant. This is not typical practice in the experience of many small manufacturers. In limited supply areas Operational Flow Order restrictions and curtailment may happen multiple times a year for interruptible supply users. In some regions even this level of curtailment is infrequent.]

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 63

Comment: In certain regions of the country, firm service contracts are no longer available and interruptible service is the only option for small manufacturing sites. When disparity between overall supply and overall demand threatens the integrity of the pipeline supply system, interruptible supply contracts are curtailed generally by Operational Flow Orders (or similar contractual requirements by another name) issued to users under their supply contract terms. These orders do not generally involve physically blocking the supply pipeline¹⁴, but rather an evaluation after the fact of possible non-contractually compliant use during the curtailment period and the institution of a fine or penalty that can be assessed as high as 10 or so times the contract gas sales price. Payment of a penalty due to unauthorized natural gas usage during an OFO is not considered an increase in the cost or unit price of natural gas or a surcharge due to market supply/demand fluctuations. The contracts and user requirements are to protect the physical integrity of the system and allow its operation in compliance with FERC or state regulations.

Example contract language from actual contracts for supply reinforce these points and should be helpful in understanding curtailment scenarios.¹⁵

The current definition could be interpreted to mean that if a company contracts for interruptible natural gas supply, where the interruption could either mean the supply is halted by the utility/FERC regulated pipeline or the facility must switch fuels to avoid contractual fines, the use of backup liquid fuel during periods of high residential/critical infrastructure demand would not constitute curtailment unless the utility/FERC regulated pipeline actually physically halts the entire supply of gas to the facility.

[Footnote 14: More drastic response such as blocking service lines generally is not considered unless more drastic curtailment situations warrant. This is not typical practice in the experience of many small manufacturers. In limited supply areas, Operational Flow Order restrictions and curtailment may happen multiple times a year for interruptible supply users. In some regions even this level of curtailment is infrequent.]

[Footnote 15: Examples of gas supply contract language: Curtailment "- a critical period in which natural gas transportation service provider issues an Operational Flow Order (OFO). The OFO is required to prevent physical damage to or to maintain the integrity and safe operations of the provider's natural gas pipeline system. *If a penalty for ignoring an OFO is assessed*..... The payment or increase in cost or unit price of natural gas for unauthorized gas usage during an OFO shall under no circumstances be considered as giving the buyer the right to violate OFOs nor shall such payment be considered a substitute for any other supply remedy available. This increase in cost or unit price of natural gas is not considered a surcharge." Moreover, helpful websites include: <http://www.ferc.gov/industries/gas/gen-info.asp> - FERC website on natural gas regulations

<http://www.ingaa.org/cms/143.aspx> - Link explaining how natural gas pipelines are regulated]

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 64

Comment: Most LDC's/FERC regulated pipelines do not have automatic shutoff capability, but rather they rely on customers taking appropriate action to reduce gas use when needed for meeting high demand or for system integrity requirements. Therefore, due to the inclusion of the word "halted" in the current definition, we are concerned that the only conditions that would meet the definition are those where the gas supply to the facility is completely stopped beyond the control of the facility. Contracts for interruptible service and the inaccessibility of firm service in some regions leave a user only a limited choice – "either use backup liquid fuel during periods of natural gas curtailment, manufacturing operations cease or violate contractual restrictions under strict penalties".

If the definition of curtailment is not revised to include contractual orders whose supply is halted or restricted due to an OFO (Operational Flow Order), interruptible supply users have but no option other than to cease operations during periods of gas curtailment and suffer the economic consequences. If that is EPA's intent, the extremely high cost to manufacturers from this result

has not been assessed. Such a cost impact would have severe effects on the US economy, with its harshest effects falling on smaller manufacturers. EPA did and directly affect small It is our belief that such

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 32

Comment: The first sentence of the definition for NG curtailment restricts the allowance for liquid firing to only periods when the supply of natural gas is "halted." A total halting of natural gas is highly unusual, rather gas supplies are typically reduced to a point where they are inadequate to maintain operations. At that point liquid firing may be employed (where the capability exists) to keep at least the most critical operations going. Thus the word "halted, must be replaced with "halted or limited to a level inadequate to maintain current operations."

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 123

Comment: EPA has proposed to amend the definition of period of natural gas curtailment (76 Fed. Reg. 80536). The definition would be amended to read as follows:

"Period of gas curtailment or supply interruption means a period of time during which the supply of gaseous fuel to an affected facility is halted for reasons beyond the control of the facility. The act of entering into a contractual agreement with a supplier of natural gas established for curtailment purposes does not constitute a reason that is under the control of a facility for the purposes of this definition. An increase in the cost or unit price of natural gas due to normal market fluctuations not during periods of supplier delivery restriction does not constitute a period of natural gas curtailment or supply interruption. On-site gaseous fuel system emergencies or equipment failures also qualify as periods of supply interruption when the emergency or failure is beyond the control of the facility."

We appreciate EPA's movement on this matter, but additional clarification is still needed. The current definition is unclear and problematic, particularly as it relates to typical requirements of interruptible gas supply contracts such as those often in place at industrial facilities. Many manufacturing companies that utilize natural gas-fired boilers and process heaters operate under contractual supply agreements with local utilities and natural gas suppliers. These entities often utilize FERC-regulated natural gas pipelines to transport natural gas supply from point of

production to the consuming manufacturing facilities. Utilities and natural gas pipelines offer limited "firm supply" contracts and "interruptible supply" contracts, as appropriate, under FERC regulations to ensure the integrity of the natural gas pipeline transportation system and to maximize service according to defined user priorities for a given supply. Hospitals for example are critical users and are afforded high priority. Interrupting or "curtailing" service is required by FERC to ensure the integrity of the pipeline system. Contracts for supply define the terms of that curtailment. Interruptible service may involve lower gas prices than firm service prices because the higher priority commands a higher price. In many areas firm service is no longer available and interruptible service is the only option for manufacturing sites.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 124

Comment: EPA has proposed to amend the definition of period of natural gas curtailment (76 Fed. Reg. 80536). The definition would be amended to read as follows:

"Period of gas curtailment or supply interruption means a period of time during which the supply of gaseous fuel to an affected facility is halted for reasons beyond the control of the facility. The act of entering into a contractual agreement with a supplier of natural gas established for curtailment purposes does not constitute a reason that is under the control of a facility for the purposes of this definition. An increase in the cost or unit price of natural gas due to normal market fluctuations not during periods of supplier delivery restriction does not constitute a period of natural gas curtailment or supply interruption. On-site gaseous fuel system emergencies or equipment failures also qualify as periods of supply interruption when the emergency or failure is beyond the control of the facility."

We appreciate EPA's movement on this matter, but additional clarification is still needed. The current definition is unclear and problematic, particularly as it relates to typical requirements of interruptible gas supply contracts such as those often in place at industrial facilities. Many manufacturing companies that utilize natural gas-fired boilers and process heaters operate under contractual supply agreements with local utilities and natural gas suppliers. These entities often utilize FERC-regulated natural gas pipelines to transport natural gas supply from point of production to the consuming manufacturing facilities. Utilities and natural gas pipelines offer limited "firm supply" contracts and "interruptible supply" contracts, as appropriate, under FERC regulations to ensure the integrity of the natural gas pipeline transportation system and to maximize service according to defined user priorities for a given supply. Hospitals for example are critical users and are afforded high priority. Interrupting or "curtailing" service is required by FERC to ensure the integrity of the pipeline system. Contracts for supply define the terms of that curtailment. Interruptible service may involve lower gas prices than firm service prices because the higher priority commands a higher price. In many areas firm service is no longer available and interruptible service is the only option for manufacturing sites.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 144

Comment: THE DEFINITION OF NATURAL GAS CURTAILMENT

EPA has proposed to amend the definition of period of natural gas curtailment as follows:

Period of gas curtailment or supply interruption means a period of time during which the supply of gaseous fuel to an affected facility is halted for reasons beyond the control of the facility. The act of entering into a contractual agreement with a supplier of natural gas established for curtailment purposes does not constitute a reason that is under the control of a facility for the purposes of this definition. An increase in the cost or unit price of natural gas due to normal market fluctuations not during periods of supplier delivery restriction does not constitute a period of natural gas curtailment or supply interruption. On-site gaseous fuel system emergencies or equipment failures qualify as periods of supply interruption when the emergency or failure is beyond the control of the facility. (76 Fed. Reg. 80536)

This definition presents a major concern for industry because the term "halted" is too restrictive and may be interpreted to interfere with existing contractual obligations. Many manufacturing companies that use natural gas fired boilers and process heaters operate under contract supply agreements with local utilities, often at reduced cost to the company, in exchange for either the utility's ability to curtail the supply or a facility's commitment to switch fuels when regional demand by residential or other critical users (e.g., hospitals) is high. Critical regional demand is frequently a function of inclement weather when residential and medical facilities require more gas than normal, thus limiting the amount of gas available to industrial customers. However, most gas suppliers do not have automatic shutoff capability so they rely on industrial customers to reduce gas use when needed.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 145

Comment: The current definition can be read to severely penalize facilities that contract for interruptible natural gas, which is the most common method of industrial gas curtailment. Interpreted literally, the current definition of curtailment includes only periods when the utility physically halts the entire supply of gas to a facility. As discussed, that is not even possible for most gas supply circumstances.

Given the many contractual arrangements possible, ACC requests that EPA modify the rule to clarify it does not intend to restrict the ability of natural gas consumers to obtain the most appropriate gas purchasing contract arrangement for their purposes. In addition, please clarify that EPA will allow use of backup liquid fuel firing under those situations where the supply of natural gas is restricted to affected facilities under a purchase contract arrangement to the extent that a very high cost or penalty would be involved for continued natural gas use at pre-restriction levels.

ACC suggests the following revision to the definition: *"Period of gas curtailment or supply interruption means a period of time during which the supply of gaseous fuel to an affected facility is halted or restricted for reasons beyond the control of the facility or due to the terms of a contractual agreement with a supplier of natural gas that allows gas curtailment or supply interruption. An increase in the cost or unit price of natural gas due to normal market fluctuations that does not occur during periods of supplier delivery restriction does not constitute a period of natural gas curtailment or supply interruption. Restriction of supply by a natural gas supplier under a contractual order (e.g., operational flow order under a user's interruptible supply contract) does constitute a period of natural gas curtailment. On-site gaseous fuel system emergencies or equipment failures also qualify as periods of supply interruption when the emergency or failure is beyond the control of the facility."*

The definition needs to be consistent between the area source and major source rules.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 126

Comment: Most utilities/FERC regulated pipelines do not have automatic shutoff capability, but rather rely on customers taking appropriate action to reduce gas use when needed. Therefore, due to the inclusion of the word "halted" in the current definition, we are concerned that the only conditions that would meet the definition are those where the gas supply to the facility is completely stopped beyond the control of the facility.

Given the many contractual arrangements possible, we request that EPA clarify that the Agency does not intend to restrict the ability of natural gas consumers to obtain the most appropriate gas purchasing contract arrangement for their purposes. In addition, please clarify that EPA will allow use of backup liquid fuel firing under those situations where the supply of natural gas is restricted to affected facilities under a purchase contract arrangement.

We suggest the following revision (see underlined text) to the definition:

"Period of gas curtailment or supply interruption means a period of time during which the supply of gaseous fuel to an affected facility is halted or restricted for reasons beyond the control of the facility or due to the terms of a contractual agreement with a supplier of natural gas that allows gas curtailment or supply interruption. An increase in the cost or unit price of natural gas

due to normal market fluctuations that does not occur during periods of supplier delivery restriction does not constitute a period of natural gas curtailment or supply interruption. Restriction of supply by a natural gas supplier under a contractual order (e.g., operational flow order under a user's interruptible supply contract) does constitute a period of natural gas curtailment. On-site gaseous fuel system emergencies or equipment failures also qualify as periods of supply interruption when the emergency or failure is beyond the control of the facility."

The definitions in both the Boiler MACT and GACT rules should be consistent.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 65

Comment: We request that EPA clarify that the Agency does not intend to restrict the ability of natural gas consumers to obtain the most appropriate gas purchasing arrangement for their purposes, while at the same time complying with FERC or State regulations. In addition, EPA should clarify that EPA will allow use of backup liquid fuel firing under those situations where the supply of natural gas is restricted to affected facilities under a purchase contract arrangement.

The revised text does not account for the many contractual arrangements possible, and the definition should be amended so that it does not restrict the ability of natural gas-fired units to obtain the most appropriate gas purchasing contract arrangement for their purposes. In addition, EPA should revise the text to allow use of backup liquid fuel firing under situations where the supply of natural gas is restricted to affected facilities under a purchase contract arrangement to the extent that a very high cost or penalty would be involved for continued natural gas use at pre-restriction levels.

We suggest the following revisions to the definition in the Proposed Reconsideration Rule:

"Period of gas curtailment or supply interruption means a period of time during which the supply of gaseous fuel to an affected facility is halted or restricted for reasons beyond the control of the facility. ~~The act of entering into or due to the terms of~~ a contractual agreement with a supplier of natural gas ~~established for curtailment purposes does not constitute a reason that is under the control of a facility for the purposes of this definition. that allows gas curtailment or supply interruption or due to the terms and conditions of a tariff or supply rate offered by the local utility provider that allows curtailment or supply interruption.~~ Restriction of supply by a natural gas supplier under a contractual order (e.g., operational flow order under an interruptible supply contract) does constitute a period of natural gas curtailment or supply interruption. An increase in the cost or unit price of natural gas due to normal market fluctuations ~~not~~ that does not occur during periods of supplier delivery restriction does not constitute a period of natural gas curtailment or supply interruption. On-site gaseous fuel system emergencies or equipment failures ~~may~~ also qualify as periods of supply interruption when the emergency or failure is beyond the control of the facility."

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 61

Comment: CIBO commented on EPA’s earlier definition of natural gas curtailment and explained its legal and factual deficiencies. In response to comments and in the Proposed Reconsidered rule, EPA did not address the critical compliance obstacle that this definition creates.

EPA’s Proposed Reconsideration makes these amendments to the definition in the Final March 2011 Rule of period of natural gas curtailment:

Period of gas curtailment or supply interruption means a period of time during which the supply of ~~natural gas~~[gaseous fuel](#) to an affected facility is halted for reasons beyond the control of the facility. The act of entering into a contractual agreement with a supplier of natural gas established for curtailment purposes does not constitute a reason that is under the control of a facility for the purposes of this definition. An increase in the cost or unit price of natural gas [due to normal market fluctuations not during periods of supplier delivery restriction](#) does not constitute a period of natural gas curtailment or supply interruption. [On-site gaseous fuel system emergencies or equipment failures may qualify as periods of supply interruption when the emergency or failure is beyond the control of the facility.](#)

76 Fed. Reg. 80653 (redline edits indicate changes to the Final Rule). EPA’s revisions on reconsideration do not address the significant concerns raised by sources. This definition continues to present a major compliance concern for industry because the term "halted" is too restrictive and may be interpreted to interfere with existing contractual obligations. The bottom line for sources is that under this narrow definition of curtailment, ordinary gas supply circumstances will result in Gas 1 sources being re-defined out of the Gas 1 category, if they make sensible market-based decisions regarding fuel availability and pricing impacts.

This definition is apparently written to protect firms whose supply is downstream of a Local Distribution Company (LDC). Users downstream of a LDC can indeed have their supply restricted or halted when the needs of users exceed the LDC’s available supply. In such a scenario, residential users, hospitals and others would be given priority and an industrial company would be shut off. In that simple case, the industrial source must burn its alternate fuel. However, most curtailments are not that simple, and instead reflect complex supply and demand circumstances that EPA does not account for in its simplistic approach to curtailments.

The proposed definition does not address the range of gas supply arrangements and would likely create confusion and eliminate routine cost-effective use of gas purchase contract arrangements. Such impacts would extend beyond EPA authority and implicate state and FERC regulatory authority. The range of gas supply arrangements can include purchase from an LDC under state jurisdiction or purchase from a gas supplier that transports the supply on a interstate/intrastate gas pipeline system under FERC jurisdiction. Purchased transportation can be firm (a consumer

contracts for a specific amount of transport capacity) or interruptible (a consumer can be interrupted by the transporting entity at the transporting entity's will), or a combination of firm and interruptible. Because a site must pay a cost for firm transportation whether the gas is actually purchased or not, many large natural gas consumers utilize contracts that incorporate a combination of firm and interruptible supply contracts to optimize transportation costs in light of variation in natural gas demand.

Normally, with purchase of firm transportation, the risk of curtailment limits a firm's delivery amount to the firm transport capacity purchased (or the firm's daily nomination, whichever is less). Curtailment typically occurs when demand is unusually high, for example, with very cold weather.

Firm transport customers are normally only subject to curtailment to less than their firm capacity when the transporter suffers a force majeure situation (e.g., a compressor station failure, pipe failure), or the supply is significantly disrupted (e.g. a major hurricane in the Gulf of Mexico).

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 33

Comment: The second sentence of the definition is "The act of entering into a contractual agreement with a supplier of natural gas established for curtailment purposes does not constitute a reason that is under the control of a facility for the purposes of this definition." This sentence appears to be making it clear that interruptible supply contracts are allowed and natural gas reductions as a result of such contracts would be an acceptable reason for firing liquid. However, the wording of the second sentence is totally unclear and should be revised to "Natural gas curtailments due to the terms of a contractual agreement with a supplier of natural gas that allows gas curtailment or supply interruption are considered periods of curtailment beyond the control of the facility."

Interruptible supply agreements are important, not only because they save money for facilities, but because they allow utilities to provide gas to critical users (e.g., residences, hospitals) when regional gas supplies are short (e.g., during hurricanes). This definition must be clear that such agreements are allowed and curtailments due to these agreements are an acceptable basis for liquid firing. If that is not the case, EPA must outline all of the implications of disallowing such agreements on the public, public health, emergency response, etc. and incorporate those impacts and the added costs of converting facilities to non-interruptible supply contracts into the rule supporting analysis and provide that information for notice and comment.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Robert D. Bessette
Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)
Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1
Comment Excerpt Number: 62

Comment: In the case of interstate/intrastate gas transportation contracts, there are provisions under which a customer hypothetically could buy natural gas in excess of its contractual firm transportation amount during a curtailment. However, penalties in pipeline tariff agreements, regulated by FERC, can be significant and are intended to make the a violation of curtailment so painful as effectively to prohibit a consumer from attempting to defy the curtailment order. As examples, one interstate pipeline tariff cites a \$15 per Dekatherm penalty on top of Henry Hub prices, effectively quadrupling the cost of natural gas and another interruptible user reports an even higher \$30 per Dekatherm penalty. The penalties of unauthorized natural gas usage during a curtailment are imposed to ensure pipeline system integrity and are not considered a unit cost increase for the price of natural gas. In contrast, for firms purchasing gas from a LDC there is little or no ability to buy supply as customers are required to honor the curtailment order. If they do not, the customer is subject to huge penalties for amounts taken above the contract quantity and pipeline system integrity can be compromised.

For interruptible service, or for that portion of a supply contract that is interruptible, transportation of natural gas on both interstate/intrastate pipelines and local distribution systems would be "halted" or "restricted" under Operational Flow Order (OFO) conditions (or pre-OFO conditions). Because many large consumers of natural gas utilize contracts that combine firm and interruptible transportation, an OFO represents an unpredictable constraint on a firm's ability to operate its plant at optimal levels. For those firms whose natural gas supply contracts consist entirely of firm delivery, this would be an infrequent event such as a Force Majeure. Many small manufacturing sites such as those subject to GACT also operate under purely interruptible service contracts. Frequency of curtailment under an OFO varies but on system's that are supply/capacity limited curtailment may run from zero to multiple events per year based on actual overall supply/distribution capacity versus actual overall demand.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Matthew Todd
Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)
Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2
Comment Excerpt Number: 31

Comment: The definition of "period of gas curtailment or supply interruption" is unclear and does not provide relief for all reasonable situations and thus needs to be revised.

EPA has proposed the following definition of period of gas curtailment or supply disruption as follows.

Period of gas curtailment or supply interruption means a period of time during which the supply of gaseous fuel to an affected facility is halted for reasons beyond the control of the facility. The act of entering into a contractual agreement with a supplier of natural gas established for curtailment purposes does not constitute a reason that is under the control of a facility for the purposes of this definition. An increase in the cost or unit price of natural gas due to normal market fluctuations not during periods of supplier delivery restriction does not constitute a period of natural gas curtailment or supply interruption. On-site gaseous fuel system emergencies or equipment failures qualify as periods of supply interruption when the emergency or failure is beyond the control of the facility.

In this definition the term “beyond the control of the facility” is used repeatedly to narrow what special cases are allowed. However, this phrase is arbitrary and unclear and puts facilities at risk of violations based on the whim of a regulator or citizen. Since EPA claims through their affirmative defense language that essentially all malfunctions are preventable, it is unclear they would consider any emergency or equipment failure to be beyond the control of the facility. Even loss of natural gas because of a pipeline rupture might not qualify, since EPA claims under the affirmative defense provisions that an event is not a malfunction if the event could “have been prevented through careful planning, proper design or better operation and maintenance practices” or stemmed “from any activity or event that could have been foreseen and avoided, API/AFPM Comments on Proposed BPH NESHAPs, CISWI and NHSM Rules Page 22 “ The phrase “beyond the control of the facility” is arbitrary and unclear and should be deleted.

[Footnote 11: See proposed §63.7501(a)(1)(ii) and (iii).]

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

115B. Electronic Reporting: WebFIRE [DENIED PETITIONER ISSUE]

Commenter Name: Lee Zeugin and Lauren Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1

Comment Excerpt Number: 44

Comment: In support of its proposal for the ERT, EPA again offers general assertions of reduced burden and emission factor improvements. With respect to the substantive content of the reports, EPA states that “[a]nother advantage is that ERT clearly states what testing information would be required.” 76 Fed. Reg. at 80,605. EPA did not respond to any of UARG’s prior comments.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Lee Zeugin and Lauren Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1

Comment Excerpt Number: 46

Comment: UARG does not object to a requirement to report data that are necessary to determine compliance, or are otherwise useful to the Agency. UARG also does not object to electronic reporting of those data. However, UARG does object to codification of vague and inadequately defined reporting requirements. Where EPA has proposed to require reporting of “performance test data” and “relative accuracy test audit data,” UARG understands those terms to refer to information already required to be reported under Subpart DDDDD. For example, when performance tests are conducted using reference methods specified in Subpart DDDDD, those promulgated methods specify what results must be reported. Similarly, when relative accuracy test audits are conducted, the applicable performance specification identifies what must be reported. To the extent additional data are needed to support compliance, EPA must specify those data in the rule. If EPA simply required the reporting of those existing data in a reasonable electronic format, UARG would not object. Unfortunately, EPA does not. EPA requires ERT.

EPA asserts that ERT clearly states what must be reported. However, ERT is not a rule. ERT is only a “tool” for reporting information as required by rule. ERT has not undergone rulemaking, or review under the PRA. EPA cannot use ERT to define what must be reported. That must be specified in the rule so that affected facilities have the opportunity to review and provide comment on the scope of the substantive reporting requirement. EPA’s outreach to stack testing companies regarding the content of ERT is not a substitute for rulemaking. Unfortunately, one need look no further than the ERT user manual to see that EPA is attempting to use ERT to establish new substantive reporting requirements. For example, no “test data” may be entered into ERT until a Test Plan has been created in ERT. Section 63.7520(a) does require development of a test plan according to § 63.7(c), which in turn requires submission of the plan “if requested.” But EPA has not formally requested submission of such test plans,²⁰ or limited the ERT Test Plan to information required under § 63.7(c). *See, e.g.*, Electronic Reporting Tool (ERT) Users Guide Version 3.1 June 2009 at 3 (describing the expanded process descriptions required so that “ERT can be used to develop and report emission factors”). A more thorough audit of ERT and its user manual undoubtedly would reveal many other examples of newly created substantive reporting requirements. Notably, neither ERT nor its user manual contain a single regulatory citation to identify the source of the substantive reporting requirement. The first step in making ERT legal is to identify for each data input a rule requiring reporting of that information.

[Footnote]

(20) Neither Subpart DDDDD, nor § 63.7(c), appear to anticipate that EPA would require that a test plan be submitted and approved prior to every performance test. Instead, after a notification of performance testing is submitted, EPA must request submission of the plan for that test.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Lee Zeugin and Lauren Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1

Comment Excerpt Number: 47

Comment: Any electronic report used to satisfy federal reporting requirements also must meet the requirements of the Cross-Media Electronic Reporting Rule, codified at 40 C.F.R. Part 3, including the requirement that the document include a valid electronic signature, as defined in the rule. EPA has made no attempt to explain how ERT, CEDRI, or WebFIRE meet this requirement. UARG also is concerned regarding the ability of ERT to satisfy other criteria EPA deems necessary for valid electronic reporting, including whether (i) each electronic signature was a valid electronic signature at the time of signing; (ii) the electronic document cannot be altered without detection at any time after being signed; and (iii) each signatory had the opportunity to review in a human readable format the content of the electronic document that he or she was certifying to, attesting to, or agreeing to by signing. *See, e.g.,* 40 C.F.R. § 3.2000(b)(5). In UARG's experience, ERT satisfies none of these criteria. Especially troublesome is the inability of the responsible official to prevent revision of the information in ERT at or after the point of submittal. EPA cannot require sources to submit data using a mechanism that does not satisfy its own requirements for such submissions. Promises by EPA that these issues will be addressed by the time reports must be submitted are not sufficient to satisfy EPA's obligations under the CAA to provide notice and opportunity for comment at the time of proposal.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Lee Zeugin and Lauren Freeman

Commenter Affiliation: Utility Air Regulatory Group (UARG)

Document Control Number: EPA-HQ-OAR-2002-0058-3500-A1

Comment Excerpt Number: 48

Comment: UARG does not agree with EPA's unsupported assertion that the information required to be submitted under ERT to WebFIRE will benefit EPA and sources by improving emission factors. EPA has yet to explain in any detail how the process of emission factor development from performance test and 30-day rolling average CEMS and CPMS data submitted to WebFIRE will work. In its comments on the ANPR, UARG expressed concerns about the process EPA described and objected to any attempts to mandate submission of reports before EPA had more completely explained its plans, completed any necessary rulemakings, and made operational its website. UARG reiterates those points here. EPA should reserve the question of mandatory reporting to WebFIRE until it has resolved the questions raised in the ANPR.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Myra Reece

Commenter Affiliation: South Carolina Department of Health and Environmental Control

Document Control Number: EPA-HQ-OAR-2002-0058-3629-A2

Comment Excerpt Number: 7

Comment: DHEC has serious reservations about facilities reporting to the EPA through the Central Data Exchange (CDX). Our concerns center around data quality and the burden of requiring facilities to submit reports to both the state, as the Delegate Agency, and to the EPA.

DHEC is encouraged by the prospect of integrating a streamlined approach to electronic submission of data, however the EPA must consider how this proposal would assure data quality and how it would impact the reporting burden on facilities. These issues should be addressed prior to moving forward. Until these concerns are addressed, DHEC has significant reservations regarding the EPA's effort to have data submitted directly to the CDX.

DHEC takes seriously our responsibility to ensure the quality of data submitted by facilities, and notes that routine requests are made for facilities to correct, revise, or supplement the data after initial submission and review. It does not appear that the data submitted through the CDX will be reviewed or revised. This will lead to inaccurate data being relied on for future use or public viewing. This would create a significant issue for public trust and transparency as well as potentially provide invalid data for future environmental permit decisions.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Robin Mills Ridgway

Commenter Affiliation: Purdue University

Document Control Number: EPA-HQ-OAR-2002-0058-3668-A2

Comment Excerpt Number: 19

Comment: In §63.7550(j), EPA proposes to require submission of parametric operating data to WebFire on a quarterly basis. Purdue University's Wade Utility Plant boilers are currently CAIR affected units for ozone season NO_x emissions. This program requires quarterly submission of emissions data to the Clean Air Markets Division via ECMPS. The process for collecting, preparing, quality assuring, and submitting this data for CAIR compliance is burdensome and, due to staff time constraints, requires the assistance of contractors specifically skilled in the preparation and submission process. To require submission of parametric monitoring data electronically would add tremendous burden and cost to Purdue's existing reporting scheme for Part 75, a program that currently costs the University \$25,000/year for data QA, data submission, and data acquisition and handling system support. As well, the state regulatory agency is unable to accept data electronically resulting in duplicative reporting with little environmental benefit.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 139

Comment: Alternative reporting mechanisms should be specified, since exclusive use of EPA's new and unproven Compliance and Emissions Data Reporting Interface and the limited ERT puts sources at risk due to failures of this unproven system. Timing of these submissions should be coordinated with the periodic reports.

1. Proposed §63.7550(j) requires periodic reports of operating parameter daily averages and that those reports be submitted using the Compliance and Emissions Data Reporting Interface, or CEDRI, which is accessed through the EPA's Central Data Exchange (CDX). However, this system has only been put into production as of the first of 2012 and is clearly unproven in regards to its reliability and accuracy. It is highly unlikely to be reliable for periodic report use for much longer than the compliance time for this rule and EPA should provide the normal paper reporting as an alternate until some future time when electronic periodic reporting is 100% proven, if this requirement is finalized. It is unreasonable to put sources at risk of violations (late reporting) because of EPA reporting tool issues or availability. A 100% reliable alternative to using the unproven CEDRI system must be made available.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 140

Comment: In §63.7550(h), (i) and (j), the rule proposes to require performance test results be submitted using the Agency's Electronic Reporting Tool (ERT). While we disagree with most of the claims stated in the preamble for the benefits of this system and believe it will add additional stack testing costs, we understand that its use for performance test results is now essentially a fait accompli. Our recent experience using the ERT for Component IV of the Refinery ICR shows that there are many problems and difficulties in trying to use the ERT and that this requirement increases burdens and puts facilities at significant risk of deviations because the ERT is unable to accept this information.

EPA has recognized this problem in the recently promulgated revisions to part 60 subpart Db. §60.46b(j)(14)⁵², where it states "Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database." Unfortunately, this sentence falls short in addressing the entire problem, because it does not indicate how to submit the information that the ERT cannot accept or how EPA will match up information that is split between the ERT submission and what we presume would be a paper submission. Nor is it clear that the cost and burden estimates supporting this rulemaking reflect the duplication that will be occurring

Thus, clarifications are needed to make this requirement more practical and to prevent violations due to ERT issues. We recommend 1) EPA incorporate the sentence quoted in the previous paragraph from §60.46b(j)(14) into §63.7550(h), (j) and (i); and 2) EPA be specific about how to submit any information that the ERT does not accept.⁵³

[Footnote 52: 77 Fed. Reg. 9460 (February 16, 2012)]

[Footnote 53: We note that EPA has currently proposed amendments (77 Fed. Reg. 1130, January 9, 2012) to most stack test methods that will change many commonly used stack test

methods if those amendments are finalized. It is unclear how promptly the ERT can be revised to handle such changes.]

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 142

Comment: Proposed §63.7515(g) requires reporting of performance tests and associated operating parameter information within 90 days after completing the test. For facilities with many BPH requiring stack tests, managing the submission of this large number of reports in paper versions to the State and in electronic and paper versions to EPA (since the ERT does not accept all of the information required) imposes large unnecessary burdens. It would be much more efficient for sources and for regulators if this information could be accumulated and submitted with the periodic report. Thus, we request that §63.7515(g) be revised to require reporting of subsequent performance test and associated required information, including ERT submissions, on the same schedule as applies to periodic reports (i.e., January 31 or July 31 for the six month calendar periods ending December 31 and June 30, respectively).

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Janice E. Nolen

Commenter Affiliation: American Lung Association

Document Control Number: EPA-HQ-OAR-2002-0058-3679-A2

Comment Excerpt Number: 15

Comment: Public records for monitoring and compliance with emissions limits. The Lung Association recommends that the records and reports of monitoring and compliance measures for emissions limits be made easily and readily accessible to the public. The public has an established right to know about the emissions of toxic substances. For 25 years, EPA has required companies to make public information on toxic chemicals released into the community through the Toxic Release Inventory (TRI). We support a system similar to TRI, where facilities are required to report toxic emissions to the database and make data relating to those emissions available online.

EPA should require boiler operators to publicly disclose and report all monitoring data and compliance documentation—including with required work practices standards—and submit those data reports to EPA for public access online. These would include data and results from performance tests of facilities and emissions that occur during malfunctions of boiler equipment. Communities have a right to know what toxic air pollutants are emitted by boilers and incinerators, the quantities of each type of pollutant being emitted, when those emissions are occurring, particularly when the emissions exceed limits set by EPA.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Janice E. Nolen

Commenter Affiliation: American Lung Association

Document Control Number: EPA-HQ-OAR-2002-0058-3679-A2

Comment Excerpt Number: 16

Comment: Public records for monitoring and compliance with emissions limits. The Lung Association recommends that the records and reports of monitoring and compliance measures for emissions limits be made easily and readily accessible to the public. The public has an established right to know about the emissions of toxic substances. For 25 years, EPA has required companies to make public information on toxic chemicals released into the community through the Toxic Release Inventory (TRI). We support a system similar to TRI, where facilities are required to report toxic emissions to the database and make data relating to those emissions available online.

EPA should require boiler operators to publicly disclose and report all monitoring data and compliance documentation—including with required work practices standards—and submit those data reports to EPA for public access online. These would include data and results from performance tests of facilities and emissions that occur during malfunctions of boiler equipment. Communities have a right to know what toxic air pollutants are emitted by boilers and incinerators, the quantities of each type of pollutant being emitted, when those emissions are occurring, particularly when the emissions exceed limits set by EPA.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

115C. Modify Gas Curtailment Notifications [DENIED PETITIONER ISSUE]

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 146

Comment: In addition, the requirement to notify EPA within 48 hours when oil is burned in a gas-fired unit due to curtailment is burdensome and unnecessary. Section 63.7545 requires facilities to submit a notice of natural gas curtailment of supply interruption when an alternate fuel is burned within 48 hours of the curtailment declaration. This notification requirement is an unnecessary burden on facilities, and it has the potential to result in numerous reporting violations. It should be sufficient for facilities to keep records of such events, make them available upon request, and summarize any such periods in the semi-annual compliance reports required by the rule.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Shannon S. Broome
Commenter Affiliation: Auto Industry Forum (AIF)
Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1
Comment Excerpt Number: 42

Comment: In the final rule, EPA imposed an additional obligation on operators of Gas 1 units during periods of NG curtailment or supply interruption. In the newly proposed 40 C.F.R. § 63.7545(f), EPA required these Gas 1 unit operators to provide notification of their use of an alternative, non-Gas 1 fuel within 48 hours of the commencement of such periods. *See Boiler MACT*, 76 Fed. Reg. at 15,679, 15,685.

In its petition for reconsideration and subsequent comments, AIF advocated for the elimination of this requirement and recommended that EPA modify any notification requirements to comport with the 6-month reporting deadlines under Title V. *See* 40 C.F.R. § 70.6(c) (including the notification as to a NG curtailment from the previous 6-month period in the Title V semi-annual report of required monitoring). AIF made this suggestion because of its concerns regarding the feasibility of EPA imposing on facilities such a short timeframe for notification and the fact that backup fuels are allowed by existing permits, rendering this requirement unnecessary.

In the proposal, § 63.7545(f) continues to contain this requirement. *See Boiler MACT Reconsideration Proposal*, 76 Fed. Reg. at 80,646. Further, EPA does not explain why it did not include this issue in the preamble or otherwise acknowledge this subject as one as to which AIF petitioned for reconsideration.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Shannon S. Broome
Commenter Affiliation: Auto Industry Forum (AIF)
Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1
Comment Excerpt Number: 43

Comment: AIF reiterates the position conveyed in its petition for reconsideration and subsequent comments: EPA should eliminate this requirement. It simply is not feasible to impose on facilities such a short timeframe for notification. EPA has previously stated that, as "curtailments are an unlikely event, so the burden of this requirement should be minimal." EPA's Responses to Public Comments on *Boiler MACT*, Vol. 2, Comment Excerpt No: 6 (Mar. 21, 2011), Document Control No: EPA-HQ-OAR-2002-0058-2894.1. The fact that such a situation may occur only infrequently, however, does not change the severity of the burden on a facility, including those owned and/or operated by AIF members, when it does occur. EPA, therefore, should eliminate the notification requirement.

In the final rule, EPA sought to justify it as functioning to "ensure that only those units that qualify as Gas 1 units remain in the Gas 1 subcategory." *See id.*, Vol. 1, at p. 895, Document Control No: EPA-HQ-OAR-2002-0058-3289. This concern, however, does not justify a 48-hour notification requirement—the selection of that notification timeframe is arbitrary and capricious; EPA fails to explain how its stated concern supports imposing 48 hours as the timeframe for the

requisite notification. If EPA elects to retain the requirement, it can still clearly achieve its stated goal by receiving any information regarding NG curtailment in Title V reports. There is no rational basis to add to facilities' monitoring burdens when Title V already requires them to report NG curtailments from the previous 6 months in their semi-annual reports of required monitoring. If it elects to retain the notification requirement, therefore, EPA should amend it to operate consistently with the timeframe of Title V's reporting regime for required monitoring, relying on reporting of changes in the semi-annual report of required monitoring, rather than imposing a 48-hour notification requirement.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Shannon S. Broome

Commenter Affiliation: Auto Industry Forum (AIF)

Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1

Comment Excerpt Number: 44

Comment: Moreover, EPA fails to provide a rational basis as to why, even in light of its stated concern, it should require any notification when facilities, in instances of NG curtailment, merely burn backup fuels. When facilities burn backup fuels, notification is unnecessary because existing permits allow the burning of backup fuels. Burning a backup fuel is not like burning a new fuel. At most, then, if EPA elects to retain the notification requirement, it should restrict the requirement to circumstances where, during instances of NG curtailment, facilities burn a fuel that was not previously identified in a permit. There is, otherwise, no rational basis for it.

Therefore, EPA should eliminate the notification requirement of alternative fuel use during NG curtailment. In the alternative, EPA should amend the timeframe of § 63.7545(f) to one that is consistent with Title V's semi-annual report of required monitoring. Moreover, EPA should only require facilities to report when they burn a new fuel, *i.e.*, one that was not previously identified or allowed under their Title V permit.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section 'Other Actions We Are Taking' for the reasons for the denial.

Commenter Name: Paul Noe

Commenter Affiliation: American Forest & Paper Association (AF&PA) et al.

Document Control Number: EPA-HQ-OAR-2002-0058-3521-A1

Comment Excerpt Number: 140

Comment: Section 63.7545 requires facilities to submit a notice of natural gas curtailment of supply interruption when an alternate fuel is burned within 48 hours of the curtailment declaration. This notification requirement is an unnecessary burden on facilities, and it has the potential to result in numerous reporting violations. It should be sufficient for facilities to keep records of such events, make them available upon request, and summarize any such periods in the semi-annual compliance reports required by the rule.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Commenter Name: Barbara Schulze

Commenter Affiliation: Merck and Co., Inc

Document Control Number: EPA-HQ-OAR-2002-0058-3546-A2

Comment Excerpt Number: 1

Comment: In the current proposal, the EPA allows gaseous fuel boilers and process heaters to burn liquid fuel for periodic testing, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year, unless there is a gas curtailment or other supply emergency. In order to maintain the ability for a dual fuel boiler to burn liquid fuel during emergencies, it is necessary to properly train operators to switch fuels safely, while maintaining proper combustion practices, thus minimizing emissions. The current annual testing and tuning alone may take up to 48 hours. A 72 hour period would provide a more adequate timeframe to complete these activities safely and ensure boilers are running proficiently in the event of a fuel switch. The emissions from the operation of the boiler for up to 24 hours more per year on liquid fuel would be negligible. However, this small addition of time to the limit on liquid fuel burning would allow for training of personnel so that they can safely operate boilers on the back-up fuel in the event of an emergency, and enable the performance of maintenance that may be required for efficient on-going operation of the boiler.

Response: This comment relates to a petition that was denied by the EPA. Refer to the preamble section ‘Other Actions We Are Taking’ for the reasons for the denial.

Table 1. List of Commenters that Submitted Comments to EPA-HQ-OAR-2002-0058

DCN	Commenter Name	Commenter Affiliation	Commenter Type
EPA-HQ-OAR-2002-0058-3423	Temple-Inland	Carole J. Stapper	Industry
EPA-HQ-OAR-2002-0058-3424	Dakota Gasification Company Great Plains Synfuels Plant	David W. Peightal	Industry
EPA-HQ-OAR-2002-0058-3427	Felix Mestey, on behalf of Donald R. Schregardus	Clean Air Act Services Steering Committee, Department of Defense (DoD)	
EPA-HQ-OAR-2002-0058-3432-A1	Michael Livermore, Jason Schwartz	Institute for Policy Integrity, NYU School of Law	
EPA-HQ-OAR-2002-0058-3435-A1	John V. Corra, Director	State of Wyoming Department of Environmental Quality	
EPA-HQ-OAR-2002-0058-3436-A1	Mark Thoma, Principal, Environmental Services Department	Otter Tail Power Company	
EPA-HQ-OAR-2002-0058-3437-A2	Dave Copeland, Manager, Air Quality, Corporate Safety and Environmental Services	Praxair Inc.	
EPA-HQ-OAR-2002-0058-3444-A1	Regina Hopper	America's Natural Gas Alliance (ANGA)	
EPA-HQ-OAR-2002-0058-3448-A1	William C. Herz	The Fertilizer Institute (TFI)	
EPA-HQ-OAR-2002-0058-3449-A1	Russell A. Wozniak	The Dow Chemical Company	
EPA-HQ-OAR-2002-0058-3451-A1	Randall D. Quintrell	Georgia Paper & Forest Products Association	
EPA-HQ-OAR-2002-0058-3452-A1	Bruce W. Ramme	Wisconsin Electric Power Company (WE Energies)	
EPA-HQ-OAR-2002-0058-3453-A1	Michael D. Wendorf	FMC Corporation	
EPA-HQ-OAR-2002-0058-3454-A1	Melvin E. Keener	Coalition for Responsible Waste Incineration (CRWI)	
EPA-HQ-OAR-2002-0058-3455-A1	John C. Hendricks	American Electric Power (AEP)	
EPA-HQ-OAR-2002-0058-3456-A2	Derek Stephens	Advanced Industrial Resources, Inc. (AIR)	
EPA-HQ-OAR-2002-0058-3457-A2	Paul G. Page	AK Steel Corporation	
EPA-HQ-OAR-2002-0058-3460-A2	Dan Bosch	National Federation of Independent Business (NFIB)	
EPA-HQ-OAR-2002-0058-3465-A1	Traylor Champion	Georgia-Pacific LLC (GP)	
EPA-HQ-OAR-2002-0058-3466-A1	John S Williams	Maine Pulp & Paper Association (MPPA)	
EPA-HQ-OAR-2002-0058-3476-A1	David L. Meeker	National Renderers Association (NRA)	
EPA-HQ-OAR-2002-0058-3477-A1	Barry Christensen	Occidental Chemical Corporation (OCC)	
EPA-HQ-OAR-2002-0058-3478-A1	Gary Melow, Director	Michigan Biomass (MB)	
EPA-HQ-OAR-2002-0058-3479-A1	Wayne J. Galler	Georgia Industry Environmental Coalition	
EPA-HQ-OAR-2002-0058-3485-A1	Claudia M. O'Brien, Latham & Watkins LLP	JELD-WEN, inc.	
EPA-HQ-OAR-2002-0058-3486-A1	Lenny Dupuis	Dominion Resources Services, Inc.	
EPA-HQ-OAR-2002-0058-3487-A1	Kenneth Anderson	Ameren Corporation	
EPA-HQ-OAR-2002-0058-3488-A1	Robert E. Hunzinger	Gainesville Regional Utilities (GRU),	

Table 1. List of Commenters that Submitted Comments to EPA-HQ-OAR-2002-0058

DCN	Commenter Name	Commenter Affiliation	Commenter Type
		Florida	
EPA-HQ-OAR-2002-0058-3489-A1	Robert Cleaves	Biomass Power Association (BPA) and California Biomass Energy Alliance (CBEA)	
EPA-HQ-OAR-2002-0058-3490-A1	Peter Pagano	American Iron and Steel Institute (AISI)	
EPA-HQ-OAR-2002-0058-3491-A1	David Foerter	Institute of Clean Air Companies (ICAC)	
EPA-HQ-OAR-2002-0058-3492-A1	Eric Guelker, Alliant Energy Corporate Services, Inc.	Interstate Power and Light Company (IPL) and Wisconsin Power and Light Company (WPL), Alliant Energy Corp.	
EPA-HQ-OAR-2002-0058-3493-A1	Dirk J. Krouskop	MeadWestvaco Corporation (MWV)	
EPA-HQ-OAR-2002-0058-3494-A1	David Hacker	United States Steel Corporation (USS)	
EPA-HQ-OAR-2002-0058-3495-A1	Michael Bradley	The Clean Energy Group	
EPA-HQ-OAR-2002-0058-3496-A1	Kevin G. Desharnais, Attorney, Mayer Brown LLP	United States Sugar Corporation	
EPA-HQ-OAR-2002-0058-3497-A1	Lisa Jacobson	Business Council for Sustainable Energy (BCSE)	
EPA-HQ-OAR-2002-0058-3498-A1	Holly R. Hart	United Steel Workers (USW)	
EPA-HQ-OAR-2002-0058-3499-A1	N.W. Bernstein & Associates, LLC	Eco Power Solutions (USA) Corporation	
EPA-HQ-OAR-2002-0058-3500-A1	Lee Zeugin and Lauren Freeman	Utility Air Regulatory Group (UARG)	
EPA-HQ-OAR-2002-0058-3501-A1	Jessica Bridges	United States Clean Heat & Power Association (USCHPA)	
EPA-HQ-OAR-2002-0058-3502-A1	Timothy Serie	American Coatings Association (ACA)	
EPA-HQ-OAR-2002-0058-3503-A1	Sarah E. Amick	Rubber Manufacturers Association (RMA)	
EPA-HQ-OAR-2002-0058-3504-A1	David A. Buff, Golder Associates Inc.	Florida Sugar Industry (FSI)	
EPA-HQ-OAR-2002-0058-3505-A1	Ashok K. Jain	National Council for Air and Stream Improvement, Inc. (NCASI)	
EPA-HQ-OAR-2002-0058-3506-A1	Arthur N. Marin	Northeast States for Coordinated Air Use Management (NESCAUM)	
EPA-HQ-OAR-2002-0058-3507-A1	Michael L. Krancer	Pennsylvania Department of Environmental Protection (DEP)	
EPA-HQ-OAR-2002-0058-3508-A1	James Johnson	United States Beet Sugar Association (USBSA)	
EPA-HQ-OAR-2002-0058-3509-A1	Charles Johnson	The Aluminum Association	
EPA-HQ-OAR-2002-0058-3510-A1	Lorraine Gershman	American Chemistry Council (ACC)	
EPA-HQ-OAR-2002-0058-3511-A1	James Pew	Earthjustice, Clean Air Council, Partnership for Policy Integrity	
EPA-HQ-OAR-2002-0058-3512-A1	Shannon S. Broome	Auto Industry Forum (AIF)	
EPA-HQ-OAR-2002-0058-3513-A1	Mark D. Pettegrew	PolyOne Corporation	
EPA-HQ-OAR-2002-0058-3515-A1	Alicia Meads	National Association of Manufacturers (NAM)	
EPA-HQ-OAR-2002-0058-3518-A1	Robert R. Perry	FirstEnergy Generation Corp (FGCO)	
EPA-HQ-OAR-2002-0058-3519-A1	Roger Martella	National Alliance of Forest Owners (NAFO)	
EPA-HQ-OAR-2002-0058-3520-A1	Chris M. Hobson	Southern Company	

Table 1. List of Commenters that Submitted Comments to EPA-HQ-OAR-2002-0058

DCN	Commenter Name	Commenter Affiliation	Commenter Type
EPA-HQ-OAR-2002-0058-3521-A1	Paul Noe	American Forest & Paper Association (AF&PA) et al.	
EPA-HQ-OAR-2002-0058-3522-A1	Dean C. DeLorey	The Amalgamated Sugar Company LLC (TASCO)	
EPA-HQ-OAR-2002-0058-3523-A1	Stephen E. Woock	Weyerhaeuser Company	
EPA-HQ-OAR-2002-0058-3524-A1	Ahmed Idriss, Capital Power Corporation	CPI USA North Carolina (CPI NC)	
EPA-HQ-OAR-2002-0058-3525-A1	Mary Sullivan Douglas	National Association of Clean Air Agencies (NACAA)	
EPA-HQ-OAR-2002-0058-3526-A1	Richard Krock	The Vinyl Institute	
EPA-HQ-OAR-2002-0058-3527-A1	Bart Sponsellar	Wisconsin Department of Natural Resources (DNR)	
EPA-HQ-OAR-2002-0058-3527-A2	Bart Sponsellar	Wisconsin Department of Natural Resources	
EPA-HQ-OAR-2002-0058-3528-A1	James M Parker	PPL Montana, LLC	
EPA-HQ-OAR-2002-0058-3529-A1	LESLIE SUE RITTS	National Environmental Development Association's Clean Air Project (NEDA/CAP)	
EPA-HQ-OAR-2002-0058-3530-A1	Susan J. Miller	Brick Industry Association (BIA)	
EPA-HQ-OAR-2002-0058-3531-A1	Responsible Citizens	John Smith	
EPA-HQ-OAR-2002-0058-3534-A1	Robert D. Bessette	Council of Industrial Boiler Owners (CIBO)	
EPA-HQ-OAR-2002-0058-3534-A2	Robert D. Bessette	Council of Industrial Boiler Owners (CIBO)	
EPA-HQ-OAR-2002-0058-3534-A3	Robert D. Bessette	Council of Industrial Boiler Owners (CIBO)	
EPA-HQ-OAR-2002-0058-3534-A4	Robert D. Bessette	Council of Industrial Boiler Owners (CIBO)	
EPA-HQ-OAR-2002-0058-3534-A5	Robert D. Bessette	Council of Industrial Boiler Owners (CIBO)	
EPA-HQ-OAR-2002-0058-3535-A2	Kevin Bloomer	Westlake Chemical Corporation	
EPA-HQ-OAR-2002-0058-3537-A2	Sarah Hedrick	Verso Paper Corp.	
EPA-HQ-OAR-2002-0058-3539-A1	Edward W. Repa	National Solid Wastes Management Association (NSWMA)	
EPA-HQ-OAR-2002-0058-3541-A1	Kristin Palecek	Flambeau River Papers	
EPA-HQ-OAR-2002-0058-3543-A1	J. Michael Geers	Duke Energy	
EPA-HQ-OAR-2002-0058-3544-A2	Louis A. Zeller	Blue Ridge Environmental Defense League	
EPA-HQ-OAR-2002-0058-3545-A2	Angela D. Marconi	Delaware Solid Waste Authority (DSWA)	
EPA-HQ-OAR-2002-0058-3546-A2	Barbara Schulze	Merck and Co., Inc	
EPA-HQ-OAR-2002-0058-3547-A2	Bruce A. Steiner	American Coke and Coal Chemical Institute (ACCCI)	
EPA-HQ-OAR-2002-0058-3548-A2	Frank H. Thorn	Newport News Shipbuilding	
EPA-HQ-OAR-2002-0058-3594-A3	Tangela Niemann	Texas Commission on Environmental Quality (TCEQ)	

Table 1. List of Commenters that Submitted Comments to EPA-HQ-OAR-2002-0058

DCN	Commenter Name	Commenter Affiliation	Commenter Type
EPA-HQ-OAR-2002-0058-3608-A1	Allison Watkins, Baker Botts	Class of '85 Regulatory Response Group	
EPA-HQ-OAR-2002-0058-3627-A2	C. Richard Neff	Cogentrix Energy, LLC	
EPA-HQ-OAR-2002-0058-3629-A2	Myra Reece	South Carolina Department of Health and Environmental Control	
EPA-HQ-OAR-2002-0058-3630-A2	Douglas Price	Tesoro Companies, Inc	
EPA-HQ-OAR-2002-0058-3658-A2	Mark Weiss	Reciprocal Energy Company	
EPA-HQ-OAR-2002-0058-3659-A2	Randal G. Oswald	Integrys Energy Group	
EPA-HQ-OAR-2002-0058-3661-A2	John M. Cullen	Masco Corporation	
EPA-HQ-OAR-2002-0058-3662-A2	Annabeth Reitter	NewPage Corporation	
EPA-HQ-OAR-2002-0058-3663-A2	Vickie Woods	Division of Air Quality, North Carolina Department of Environment and Natural Resources (NCDENR)	
EPA-HQ-OAR-2002-0058-3664-A2	Linda Miller	New Jersey Department of Environmental Protection (NJDEP)	
EPA-HQ-OAR-2002-0058-3665-A2	Stuart A. Clark	State of Washington Department of Ecology	
EPA-HQ-OAR-2002-0058-3667-A2	Jennifer Youngblood	National Tribal Air Association	
EPA-HQ-OAR-2002-0058-3668-A2	Robin Mills Ridgway	Purdue University	
EPA-HQ-OAR-2002-0058-3669-A2	Steve Gossett	Eastman Chemical Company	
EPA-HQ-OAR-2002-0058-3670-A2	Pat Dennis	Archer Daniels Midland Company	
EPA-HQ-OAR-2002-0058-3671-A2	Shawn Good	Pennsylvania Chamber of Business and Industry	
EPA-HQ-OAR-2002-0058-3672-A2	Pamela Lacey	American Gas Association (AGA)	
EPA-HQ-OAR-2002-0058-3673-A2	Christopher Coleman	HOVENSA LLC. , Hess Corporation	
EPA-HQ-OAR-2002-0058-3674-A2	Robert Ellerhorst	Michigan State University	
EPA-HQ-OAR-2002-0058-3675-A2	Douglas Emerson et al.	American Crystal Sugar Company et al.	
EPA-HQ-OAR-2002-0058-3676-A2	Bill Lane	American Home Furnishings Alliance (AHFA)	
EPA-HQ-OAR-2002-0058-3677-A2	Matthew Todd	American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)	
EPA-HQ-OAR-2002-0058-3679-A2	Janice E. Nolen	American Lung Association	
EPA-HQ-OAR-2002-0058-3680-A2	Erika Frank	Calgon Carbon Corp.	
EPA-HQ-OAR-2002-0058-3681-A2	Kerry Kelly	Waste Management (WM)	
EPA-HQ-OAR-2002-0058-3682-A2	Rick Rosvold	Xcel Energy Services, Inc.	
EPA-HQ-OAR-2002-0058-3683-A2	David Gardiner	The Alliance for Industrial Efficiency	
EPA-HQ-OAR-2002-0058-3684-A2	Mark Anthony	Alyeska Pipeline Service Company	
EPA-HQ-OAR-2002-0058-3685-A2	Douglas A. McWilliams	American Municipal Power	
EPA-HQ-OAR-2002-0058-3686-A2	Richard D. Garber	Boise Inc.	
EPA-HQ-OAR-2002-0058-3687-A2	Lisa Barry	Chevron Corporation	
EPA-HQ-OAR-2002-0058-3688-A2	Nina Butler	Rock-Tenn Company	
EPA-HQ-OAR-2002-0058-3689-A2	Dan F. Hunter	ConocoPhillips Company	
EPA-HQ-OAR-2002-0058-3691-A2	Heather Parent	Maine Department of Environmental	

Table 1. List of Commenters that Submitted Comments to EPA-HQ-OAR-2002-0058

DCN	Commenter Name	Commenter Affiliation	Commenter Type
		Protection	
EPA-HQ-OAR-2002-0058-3692-A2	Dell Majure	Kimberly-Clark Corp.	
EPA-HQ-OAR-2002-0058-3744-A1	Jim Cetrullo	TestAmerica	
EPA-HQ-OAR-2002-0058-3755-A1	Samuel H. Bruntz	Alcoa Power Generating, Inc.	
EPA-HQ-OAR-2002-0058-3759-A1	Brent Roberts	International Association of Machinists and Aerospace Workers, Local Lodge 1713	
EPA-HQ-OAR-2002-0058-3770-A1	Lorna Fear	Visual Cue Thermal Imaging	
EPA-HQ-OAR-2002-0058-3778-A1	Elizabeth McMeekin	PPG Industries, Inc	
EPA-HQ-OAR-2002-0058-3786-A1	Bill Wilson	Washington State University	
EPA-HQ-OAR-2002-0058-3795-A1	Cheryl Suttman	Ohio EPA, Division of Air Pollution Control	
EPA-HQ-OAR-2002-0058-3803-A1	Michael Cassidy	Kohler Co.	
EPA-HQ-OAR-2002-0058-3808-A1	Monica Lopes	NAES Corporation	
EPA-HQ-OAR-2002-0058-3814-A1	M.L. Steele	CraftMaster Manufacturing, Inc.	
EPA-HQ-OAR-2002-0058-3815-A1	Philip Lewis	Michigan Biomass - Grayling Generating Station	
EPA-HQ-OAR-2002-0058-3817-A2	R. Thomas Buffenbarger	International Association of Machinists and Aerospace Workers	
EPA-HQ-OAR-2002-0058-3818-A2	Michael Draper	United Brotherhood of Carpenters and Joiners of America	
EPA-HQ-OAR-2002-0058-3825-A1	Gretchen Brewer	PT AirWatchers	

Table 2. Commenters that have submitted comments on topics addressed in section V of the preamble

Comment Topic	DCN	Comment Excerpt Number	Commenter Affiliation	Commenter Name
100B. All Gas	EPA-HQ-OAR-2002-0058-3677-A2	40	American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)	Matthew Todd
100C. NG Water Heaters	EPA-HQ-OAR-2002-0058-3512-A1	31	Auto Industry Forum (AIF)	Shannon S. Broome
100C. NG Water Heaters	EPA-HQ-OAR-2002-0058-3512-A1	32	Auto Industry Forum (AIF)	Shannon S. Broome
100C. NG Water Heaters	EPA-HQ-OAR-2002-0058-3512-A1	33	Auto Industry Forum (AIF)	Shannon S. Broome
100D. NG and Oil Hot Water Systems, <=10	EPA-HQ-OAR-2002-0058-3512-A1	34	Auto Industry Forum (AIF)	Shannon S. Broome
100D. NG and Oil Hot Water Systems, <=10	EPA-HQ-OAR-2002-0058-3512-A1	35	Auto Industry Forum (AIF)	Shannon S. Broome
100D. NG and Oil Hot Water Systems, <=10	EPA-HQ-OAR-2002-0058-3512-A1	36	Auto Industry Forum (AIF)	Shannon S. Broome
100D. NG and Oil Hot Water Systems, <=10	EPA-HQ-OAR-2002-0058-3512-A1	37	Auto Industry Forum (AIF)	Shannon S. Broome
100D. NG and Oil Hot Water Systems, <=10	EPA-HQ-OAR-2002-0058-3512-A1	38	Auto Industry Forum (AIF)	Shannon S. Broome
100D. NG and Oil Hot Water Systems, <=10	EPA-HQ-OAR-2002-0058-3512-A1	39	Auto Industry Forum (AIF)	Shannon S. Broome
100D. NG and Oil Hot Water Systems, <=10	EPA-HQ-OAR-2002-0058-3534-A1	13	Council of Industrial Boiler Owners (CIBO)	Robert D. Bessette
100F. Blast Furnaces	EPA-HQ-OAR-2002-0058-3457-A2	2	AK Steel Corporation	Paul G. Page
100F. Blast Furnaces	EPA-HQ-OAR-2002-0058-3457-A2	3	AK Steel Corporation	Paul G. Page
100F. Blast Furnaces	EPA-HQ-OAR-2002-0058-3490-A1	8	American Iron and Steel Institute (AISI)	Peter Pagano
100F. Blast Furnaces	EPA-HQ-OAR-2002-0058-3490-A1	9	American Iron and Steel Institute (AISI)	Peter Pagano
100G. Exhaust used in Direct-Fired PH	EPA-HQ-OAR-2002-0058-3465-A1	23	Georgia-Pacific LLC (GP)	Traylor Champion
101A. Emissions Standards for Gas 1 Units	EPA-HQ-OAR-2002-0058-3449-A1	2	The Dow Chemical Company	Russell A. Wozniak
101A. Emissions Standards for Gas 1 Units	EPA-HQ-OAR-2002-0058-3451-A1	17	Georgia Paper & Forest Products Association	Randall D. Quintrell
101A. Emissions Standards for Gas 1 Units	EPA-HQ-OAR-2002-0058-3465-A1	1	Georgia-Pacific LLC (GP)	Traylor Champion
101A. Emissions Standards for Gas 1 Units	EPA-HQ-OAR-2002-0058-3476-A1	13	National Renderers Association (NRA)	David L. Meeker
101A. Emissions Standards for Gas 1 Units	EPA-HQ-OAR-2002-0058-3477-A1	1	Occidental Chemical Corporation (OCC)	Barry Christensen
101A. Emissions Standards for Gas 1 Units	EPA-HQ-OAR-2002-0058-3486-A1	4	Dominion Resources Services, Inc.	Lenny Dupuis
101A. Emissions Standards for Gas 1 Units	EPA-HQ-OAR-2002-0058-3490-A1	13	American Iron and Steel Institute (AISI)	Peter Pagano
101A. Emissions Standards for Gas 1 Units	EPA-HQ-OAR-2002-0058-3493-A1	10	MeadWestvaco Corporation (MWV)	Dirk J. Krouskop
101A. Emissions Standards for Gas 1 Units	EPA-HQ-OAR-2002-0058-3493-A1	11	MeadWestvaco Corporation (MWV)	Dirk J. Krouskop

Table 2. Commenters that have submitted comments on topics addressed in section V of the preamble

Comment Topic	DCN	Comment Excerpt Number	Commenter Affiliation	Commenter Name
101A. Emissions Standards for Gas 1 Units	EPA-HQ-OAR-2002-0058-3501-A1	5	United States Clean Heat & Power Association (USCHPA)	Jessica Bridges
101A. Emissions Standards for Gas 1 Units	EPA-HQ-OAR-2002-0058-3510-A1	31	American Chemistry Council (ACC)	Lorraine Gershman
101A. Emissions Standards for Gas 1 Units	EPA-HQ-OAR-2002-0058-3511-A1	40	Earthjustice, Clean Air Council, Partnership for Policy Integrity	James Pew
101A. Emissions Standards for Gas 1 Units	EPA-HQ-OAR-2002-0058-3511-A1	45	Earthjustice, Clean Air Council, Partnership for Policy Integrity	James Pew
101A. Emissions Standards for Gas 1 Units	EPA-HQ-OAR-2002-0058-3515-A1	4	National Association of Manufacturers (NAM)	Alicia Meads
101A. Emissions Standards for Gas 1 Units	EPA-HQ-OAR-2002-0058-3521-A1	3	American Forest & Paper Association (AF&PA) et al.	Paul Noe
101A. Emissions Standards for Gas 1 Units	EPA-HQ-OAR-2002-0058-3521-A1	4	American Forest & Paper Association (AF&PA) et al.	Paul Noe
101A. Emissions Standards for Gas 1 Units	EPA-HQ-OAR-2002-0058-3521-A1	5	American Forest & Paper Association (AF&PA) et al.	Paul Noe
101A. Emissions Standards for Gas 1 Units	EPA-HQ-OAR-2002-0058-3521-A1	7	American Forest & Paper Association (AF&PA) et al.	Paul Noe
101A. Emissions Standards for Gas 1 Units	EPA-HQ-OAR-2002-0058-3521-A1	8	American Forest & Paper Association (AF&PA) et al.	Paul Noe
101A. Emissions Standards for Gas 1 Units	EPA-HQ-OAR-2002-0058-3521-A1	9	American Forest & Paper Association (AF&PA) et al.	Paul Noe
101A. Emissions Standards for Gas 1 Units	EPA-HQ-OAR-2002-0058-3525-A1	28	National Association of Clean Air Agencies (NACAA)	Mary Sullivan Douglas
101A. Emissions Standards for Gas 1 Units	EPA-HQ-OAR-2002-0058-3525-A1	29	National Association of Clean Air Agencies (NACAA)	Mary Sullivan Douglas
101A. Emissions Standards for Gas 1 Units	EPA-HQ-OAR-2002-0058-3526-A1	4	The Vinyl Institute	Richard Krock
101A. Emissions Standards for Gas 1 Units	EPA-HQ-OAR-2002-0058-3526-A1	5	The Vinyl Institute	Richard Krock
101A. Emissions Standards for Gas 1 Units	EPA-HQ-OAR-2002-0058-3534-A1	96	Council of Industrial Boiler Owners (CIBO)	Robert D. Bessette
101A. Emissions Standards for Gas 1 Units	EPA-HQ-OAR-2002-0058-3547-A2	6	American Coke and Coal Chemical Institute (ACCCI)	Bruce A. Steiner
101A. Emissions Standards for Gas 1 Units	EPA-HQ-OAR-2002-0058-3547-A2	7	American Coke and Coal Chemical Institute (ACCCI)	Bruce A. Steiner
101A. Emissions Standards for Gas 1 Units	EPA-HQ-OAR-2002-0058-3661-A2	3	Masco Corporation	John M. Cullen
101A. Emissions Standards for Gas 1 Units	EPA-HQ-OAR-2002-0058-3662-A2	2	NewPage Corporation	Annabeth Reitter
101A. Emissions Standards for Gas 1 Units	EPA-HQ-OAR-2002-0058-3672-A2	1	American Gas Association (AGA)	Pamela Lacey
101A. Emissions Standards for Gas 1 Units	EPA-HQ-OAR-2002-0058-3677-A2	4	American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)	Matthew Todd
101A. Emissions Standards for Gas 1 Units	EPA-HQ-OAR-2002-0058-3677-A2	39	American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)	Matthew Todd

Table 2. Commenters that have submitted comments on topics addressed in section V of the preamble

Comment Topic	DCN	Comment Excerpt Number	Commenter Affiliation	Commenter Name
101A. Emissions Standards for Gas 1 Units	EPA-HQ-OAR-2002-0058-3677-A2	43	American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)	Matthew Todd
101A. Emissions Standards for Gas 1 Units	EPA-HQ-OAR-2002-0058-3679-A2	10	American Lung Association	Janice E. Nolen
101A. Emissions Standards for Gas 1 Units	EPA-HQ-OAR-2002-0058-3778-A1	1	PPG Industries, Inc	Elizabeth McMeekin
101A. Emissions Standards for Gas 1 Units	EPA-HQ-OAR-2002-0058-3778-A1	3	PPG Industries, Inc	Elizabeth McMeekin
101A. Emissions Standards for Gas 1 Units	EPA-HQ-OAR-2002-0058-3778-A1	4	PPG Industries, Inc	Elizabeth McMeekin
101B. Elimination of Work Practices for Small Units	EPA-HQ-OAR-2002-0058-3486-A1	5	Dominion Resources Services, Inc.	Lenny Dupuis
101B. Elimination of Work Practices for Small Units	EPA-HQ-OAR-2002-0058-3487-A1	7	Ameren Corporation	Kenneth Anderson
101B. Elimination of Work Practices for Small Units	EPA-HQ-OAR-2002-0058-3511-A1	43	Earthjustice, Clean Air Council, Partnership for Policy Integrity	James Pew
101B. Elimination of Work Practices for Small Units	EPA-HQ-OAR-2002-0058-3518-A1	2	FirstEnergy Generation Corp (FGCO)	Robert R. Perry
102A. PM as a Surrogate for Non-Mercury Metallic HAP	EPA-HQ-OAR-2002-0058-3511-A1	7	Earthjustice, Clean Air Council, Partnership for Policy Integrity	James Pew
102A. PM as a Surrogate for Non-Mercury Metallic HAP	EPA-HQ-OAR-2002-0058-3511-A1	9	Earthjustice, Clean Air Council, Partnership for Policy Integrity	James Pew
102A. PM as a Surrogate for Non-Mercury Metallic HAP	EPA-HQ-OAR-2002-0058-3511-A1	10	Earthjustice, Clean Air Council, Partnership for Policy Integrity	James Pew
102A. PM as a Surrogate for Non-Mercury Metallic HAP	EPA-HQ-OAR-2002-0058-3521-A1	87	American Forest & Paper Association (AF&PA) et al.	Paul Noe
102B. CO as a Surrogate for Organic HAP	EPA-HQ-OAR-2002-0058-3485-A1	9	JELD-WEN, inc.	Claudia M. O'Brien, Latham & Watkins LLP
102B. CO as a Surrogate for Organic HAP	EPA-HQ-OAR-2002-0058-3485-A1	10	JELD-WEN, inc.	Claudia M. O'Brien, Latham & Watkins LLP
102B. CO as a Surrogate for Organic HAP	EPA-HQ-OAR-2002-0058-3511-A1	8	Earthjustice, Clean Air Council, Partnership for Policy Integrity	James Pew
102C. Work Practice for Organic HAP	EPA-HQ-OAR-2002-0058-3454-A1	4	Coalition for Responsible Waste Incineration (CRWI)	Melvin E. Keener
102C. Work Practice for Organic HAP	EPA-HQ-OAR-2002-0058-3485-A1	8	JELD-WEN, inc.	Claudia M. O'Brien, Latham & Watkins LLP
102C. Work Practice for Organic HAP	EPA-HQ-OAR-2002-0058-3485-A1	11	JELD-WEN, inc.	Claudia M. O'Brien, Latham & Watkins LLP
102C. Work Practice for Organic HAP	EPA-HQ-OAR-2002-0058-3485-A1	12	JELD-WEN, inc.	Claudia M. O'Brien, Latham & Watkins LLP
102C. Work Practice for Organic HAP	EPA-HQ-OAR-2002-0058-3485-A1	13	JELD-WEN, inc.	Claudia M. O'Brien, Latham & Watkins LLP
102C. Work Practice for Organic HAP	EPA-HQ-OAR-2002-0058-3492-A1	2	Interstate Power and Light Company (IPL) and Wisconsin Power and Light Company (WPL), Alliant Energy Corp.	Eric Guelker, Alliant Energy Corporate Services, Inc.

Table 2. Commenters that have submitted comments on topics addressed in section V of the preamble

Comment Topic	DCN	Comment Excerpt Number	Commenter Affiliation	Commenter Name
102C. Work Practice for Organic HAP	EPA-HQ-OAR-2002-0058-3492-A1	3	Interstate Power and Light Company (IPL) and Wisconsin Power and Light Company (WPL), Alliant Energy Corp.	Eric Guelker, Alliant Energy Corporate Services, Inc.
102C. Work Practice for Organic HAP	EPA-HQ-OAR-2002-0058-3500-A1	3	Utility Air Regulatory Group (UARG)	Lee Zeugin and Lauren Freeman
102C. Work Practice for Organic HAP	EPA-HQ-OAR-2002-0058-3521-A1	50	American Forest & Paper Association (AF&PA) et al.	Paul Noe
102C. Work Practice for Organic HAP	EPA-HQ-OAR-2002-0058-3534-A1	34	Council of Industrial Boiler Owners (CIBO)	Robert D. Bessette
102C. Work Practice for Organic HAP	EPA-HQ-OAR-2002-0058-3608-A1	7	Class of '85 Regulatory Response Group	Allison Watkins, Baker Botts
102C. Work Practice for Organic HAP	EPA-HQ-OAR-2002-0058-3659-A2	7	Integritys Energy Group	Randal G. Oswald
102C. Work Practice for Organic HAP	EPA-HQ-OAR-2002-0058-3668-A2	9	Purdue University	Robin Mills Ridgway
102C. Work Practice for Organic HAP	EPA-HQ-OAR-2002-0058-3669-A2	1	Eastman Chemical Company	Steve Gossett
102C. Work Practice for Organic HAP	EPA-HQ-OAR-2002-0058-3669-A2	2	Eastman Chemical Company	Steve Gossett
102C. Work Practice for Organic HAP	EPA-HQ-OAR-2002-0058-3674-A2	1	Michigan State University	Robert Ellerhorst
102C. Work Practice for Organic HAP	EPA-HQ-OAR-2002-0058-3674-A2	6	Michigan State University	Robert Ellerhorst
102C. Work Practice for Organic HAP	EPA-HQ-OAR-2002-0058-3674-A2	7	Michigan State University	Robert Ellerhorst
102C. Work Practice for Organic HAP	EPA-HQ-OAR-2002-0058-3677-A2	59	American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)	Matthew Todd
102C. Work Practice for Organic HAP	EPA-HQ-OAR-2002-0058-3685-A2	24	American Municipal Power	Douglas A. McWilliams
102C. Work Practice for Organic HAP	EPA-HQ-OAR-2002-0058-3685-A2	25	American Municipal Power	Douglas A. McWilliams
102C. Work Practice for Organic HAP	EPA-HQ-OAR-2002-0058-3778-A1	2	PPG Industries, Inc	Elizabeth McMeekin
102E. Alternative CO Standards Corrected to a CO2 Concentration	EPA-HQ-OAR-2002-0058-3465-A1	27	Georgia-Pacific LLC (GP)	Traylor Champion
102E. Alternative CO Standards Corrected to a CO2 Concentration	EPA-HQ-OAR-2002-0058-3466-A1	4	Maine Pulp & Paper Association (MPPA)	John S Williams
102E. Alternative CO Standards Corrected to a CO2 Concentration	EPA-HQ-OAR-2002-0058-3682-A2	2	Xcel Energy Services, Inc.	Rick Rosvold
102E. Alternative CO Standards Corrected to a CO2 Concentration	EPA-HQ-OAR-2002-0058-3691-A2	10	Maine Department of Environmental Protection	Heather Parent
102F. Alternative Standards for THC	EPA-HQ-OAR-2002-0058-3534-A1	41	Council of Industrial Boiler Owners (CIBO)	Robert D. Bessette
102F. Alternative Standards for THC	EPA-HQ-OAR-2002-0058-3669-A2	28	Eastman Chemical Company	Steve Gossett
102F. Alternative Standards for THC	EPA-HQ-OAR-2002-0058-3669-A2	29	Eastman Chemical Company	Steve Gossett
102F. Alternative Standards for THC	EPA-HQ-OAR-2002-0058-3669-A2	30	Eastman Chemical Company	Steve Gossett
102F. Alternative Standards for THC	EPA-HQ-OAR-2002-0058-3670-A2	9	Archer Daniels Midland Company	Pat Dennis

Table 2. Commenters that have submitted comments on topics addressed in section V of the preamble

Comment Topic	DCN	Comment Excerpt Number	Commenter Affiliation	Commenter Name
102H. HCl as a Surrogate for Acid Gases	EPA-HQ-OAR-2002-0058-3511-A1	11	Earthjustice, Clean Air Council, Partnership for Policy Integrity	James Pew
103A. MACT Floor Methodology: Statistical Approach (“Best of the Best”)	EPA-HQ-OAR-2002-0058-3496-A1	15	United States Sugar Corporation	Kevin G. Desharnais, Attorney, Mayer Brown LLP
103A. MACT Floor Methodology: Statistical Approach (“Best of the Best”)	EPA-HQ-OAR-2002-0058-3503-A1	7	Rubber Manufacturers Association (RMA)	Sarah E. Amick
103A. MACT Floor Methodology: Statistical Approach (“Best of the Best”)	EPA-HQ-OAR-2002-0058-3503-A1	8	Rubber Manufacturers Association (RMA)	Sarah E. Amick
103A. MACT Floor Methodology: Statistical Approach (“Best of the Best”)	EPA-HQ-OAR-2002-0058-3503-A1	9	Rubber Manufacturers Association (RMA)	Sarah E. Amick
103A. MACT Floor Methodology: Statistical Approach (“Best of the Best”)	EPA-HQ-OAR-2002-0058-3503-A1	10	Rubber Manufacturers Association (RMA)	Sarah E. Amick
103A. MACT Floor Methodology: Statistical Approach (“Best of the Best”)	EPA-HQ-OAR-2002-0058-3503-A1	11	Rubber Manufacturers Association (RMA)	Sarah E. Amick
103A. MACT Floor Methodology: Statistical Approach (“Best of the Best”)	EPA-HQ-OAR-2002-0058-3503-A1	12	Rubber Manufacturers Association (RMA)	Sarah E. Amick
103A. MACT Floor Methodology: Statistical Approach (“Best of the Best”)	EPA-HQ-OAR-2002-0058-3510-A1	23	American Chemistry Council (ACC)	Lorraine Gershman
103A. MACT Floor Methodology: Statistical Approach (“Best of the Best”)	EPA-HQ-OAR-2002-0058-3510-A1	73	American Chemistry Council (ACC)	Lorraine Gershman
103A. MACT Floor Methodology: Statistical Approach (“Best of the Best”)	EPA-HQ-OAR-2002-0058-3510-A1	75	American Chemistry Council (ACC)	Lorraine Gershman
103A. MACT Floor Methodology: Statistical Approach (“Best of the Best”)	EPA-HQ-OAR-2002-0058-3510-A1	77	American Chemistry Council (ACC)	Lorraine Gershman
103A. MACT Floor Methodology: Statistical Approach (“Best of the Best”)	EPA-HQ-OAR-2002-0058-3511-A1	13	Earthjustice, Clean Air Council, Partnership for Policy Integrity	James Pew
103A. MACT Floor Methodology: Statistical Approach (“Best of the Best”)	EPA-HQ-OAR-2002-0058-3511-A1	16	Earthjustice, Clean Air Council, Partnership for Policy Integrity	James Pew
103A. MACT Floor Methodology: Statistical Approach (“Best of the Best”)	EPA-HQ-OAR-2002-0058-3511-A1	17	Earthjustice, Clean Air Council, Partnership for Policy Integrity	James Pew
103A. MACT Floor Methodology: Statistical Approach (“Best of the Best”)	EPA-HQ-OAR-2002-0058-3511-A1	23	Earthjustice, Clean Air Council, Partnership for Policy Integrity	James Pew
103A. MACT Floor Methodology: Statistical Approach (“Best of the Best”)	EPA-HQ-OAR-2002-0058-3511-A1	24	Earthjustice, Clean Air Council, Partnership for Policy Integrity	James Pew
103A. MACT Floor Methodology: Statistical Approach (“Best of the Best”)	EPA-HQ-OAR-2002-0058-3511-A1	25	Earthjustice, Clean Air Council, Partnership for Policy Integrity	James Pew

Table 2. Commenters that have submitted comments on topics addressed in section V of the preamble

Comment Topic	DCN	Comment Excerpt Number	Commenter Affiliation	Commenter Name
103A. MACT Floor Methodology: Statistical Approach (“Best of the Best”)	EPA-HQ-OAR-2002-0058-3511-A1	27	Earthjustice, Clean Air Council, Partnership for Policy Integrity	James Pew
103A. MACT Floor Methodology: Statistical Approach (“Best of the Best”)	EPA-HQ-OAR-2002-0058-3511-A1	28	Earthjustice, Clean Air Council, Partnership for Policy Integrity	James Pew
103A. MACT Floor Methodology: Statistical Approach (“Best of the Best”)	EPA-HQ-OAR-2002-0058-3521-A1	35	American Forest & Paper Association (AF&PA) et al.	Paul Noe
103A. MACT Floor Methodology: Statistical Approach (“Best of the Best”)	EPA-HQ-OAR-2002-0058-3521-A1	36	American Forest & Paper Association (AF&PA) et al.	Paul Noe
103A. MACT Floor Methodology: Statistical Approach (“Best of the Best”)	EPA-HQ-OAR-2002-0058-3521-A1	39	American Forest & Paper Association (AF&PA) et al.	Paul Noe
103A. MACT Floor Methodology: Statistical Approach (“Best of the Best”)	EPA-HQ-OAR-2002-0058-3521-A1	40	American Forest & Paper Association (AF&PA) et al.	Paul Noe
103A. MACT Floor Methodology: Statistical Approach (“Best of the Best”)	EPA-HQ-OAR-2002-0058-3521-A1	53	American Forest & Paper Association (AF&PA) et al.	Paul Noe
103A. MACT Floor Methodology: Statistical Approach (“Best of the Best”)	EPA-HQ-OAR-2002-0058-3521-A1	54	American Forest & Paper Association (AF&PA) et al.	Paul Noe
103A. MACT Floor Methodology: Statistical Approach (“Best of the Best”)	EPA-HQ-OAR-2002-0058-3521-A1	55	American Forest & Paper Association (AF&PA) et al.	Paul Noe
103A. MACT Floor Methodology: Statistical Approach (“Best of the Best”)	EPA-HQ-OAR-2002-0058-3521-A1	56	American Forest & Paper Association (AF&PA) et al.	Paul Noe
103A. MACT Floor Methodology: Statistical Approach (“Best of the Best”)	EPA-HQ-OAR-2002-0058-3521-A1	57	American Forest & Paper Association (AF&PA) et al.	Paul Noe
103A. MACT Floor Methodology: Statistical Approach (“Best of the Best”)	EPA-HQ-OAR-2002-0058-3521-A1	68	American Forest & Paper Association (AF&PA) et al.	Paul Noe
103A. MACT Floor Methodology: Statistical Approach (“Best of the Best”)	EPA-HQ-OAR-2002-0058-3525-A1	2	National Association of Clean Air Agencies (NACAA)	Mary Sullivan Douglas
103A. MACT Floor Methodology: Statistical Approach (“Best of the Best”)	EPA-HQ-OAR-2002-0058-3525-A1	4	National Association of Clean Air Agencies (NACAA)	Mary Sullivan Douglas
103A. MACT Floor Methodology: Statistical Approach (“Best of the Best”)	EPA-HQ-OAR-2002-0058-3525-A1	5	National Association of Clean Air Agencies (NACAA)	Mary Sullivan Douglas
103A. MACT Floor Methodology: Statistical Approach (“Best of the Best”)	EPA-HQ-OAR-2002-0058-3525-A1	7	National Association of Clean Air Agencies (NACAA)	Mary Sullivan Douglas
103A. MACT Floor Methodology: Statistical Approach (“Best of the Best”)	EPA-HQ-OAR-2002-0058-3525-A1	10	National Association of Clean Air Agencies (NACAA)	Mary Sullivan Douglas
103A. MACT Floor Methodology: Statistical Approach (“Best of the Best”)	EPA-HQ-OAR-2002-0058-3525-A1	12	National Association of Clean Air Agencies (NACAA)	Mary Sullivan Douglas

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Comment Topic	DCN	Comment Excerpt Number	Commenter Affiliation	Commenter Name
103A. MACT Floor Methodology: Statistical Approach (“Best of the Best”)	EPA-HQ-OAR-2002-0058-3525-A1	18	National Association of Clean Air Agencies (NACAA)	Mary Sullivan Douglas
103A. MACT Floor Methodology: Statistical Approach (“Best of the Best”)	EPA-HQ-OAR-2002-0058-3525-A1	19	National Association of Clean Air Agencies (NACAA)	Mary Sullivan Douglas
103A. MACT Floor Methodology: Statistical Approach (“Best of the Best”)	EPA-HQ-OAR-2002-0058-3525-A1	20	National Association of Clean Air Agencies (NACAA)	Mary Sullivan Douglas
103A. MACT Floor Methodology: Statistical Approach (“Best of the Best”)	EPA-HQ-OAR-2002-0058-3525-A1	22	National Association of Clean Air Agencies (NACAA)	Mary Sullivan Douglas
103A. MACT Floor Methodology: Statistical Approach (“Best of the Best”)	EPA-HQ-OAR-2002-0058-3525-A1	27	National Association of Clean Air Agencies (NACAA)	Mary Sullivan Douglas
103A. MACT Floor Methodology: Statistical Approach (“Best of the Best”)	EPA-HQ-OAR-2002-0058-3525-A1	35	National Association of Clean Air Agencies (NACAA)	Mary Sullivan Douglas
103A. MACT Floor Methodology: Statistical Approach (“Best of the Best”)	EPA-HQ-OAR-2002-0058-3525-A1	55	National Association of Clean Air Agencies (NACAA)	Mary Sullivan Douglas
103A. MACT Floor Methodology: Statistical Approach (“Best of the Best”)	EPA-HQ-OAR-2002-0058-3525-A1	59	National Association of Clean Air Agencies (NACAA)	Mary Sullivan Douglas
103A. MACT Floor Methodology: Statistical Approach (“Best of the Best”)	EPA-HQ-OAR-2002-0058-3534-A1	20	Council of Industrial Boiler Owners (CIBO)	Robert D. Bessette
103A. MACT Floor Methodology: Statistical Approach (“Best of the Best”)	EPA-HQ-OAR-2002-0058-3534-A1	21	Council of Industrial Boiler Owners (CIBO)	Robert D. Bessette
103A. MACT Floor Methodology: Statistical Approach (“Best of the Best”)	EPA-HQ-OAR-2002-0058-3676-A2	4	American Home Furnishings Alliance (AHFA)	Bill Lane
103A. MACT Floor Methodology: Statistical Approach (“Best of the Best”)	EPA-HQ-OAR-2002-0058-3685-A2	28	American Municipal Power	Douglas A. McWilliams
103C. MACT Floor Methodology: Ranking by Average	EPA-HQ-OAR-2002-0058-3511-A1	12	Earthjustice, Clean Air Council, Partnership for Policy Integrity	James Pew
103C. MACT Floor Methodology: Ranking by Average	EPA-HQ-OAR-2002-0058-3525-A1	9	National Association of Clean Air Agencies (NACAA)	Mary Sullivan Douglas
103D. MACT Floor Methodology: Pollutant-by-Pollutant Approach	EPA-HQ-OAR-2002-0058-3496-A1	14	United States Sugar Corporation	Kevin G. Desharnais, Attorney, Mayer Brown LLP
103D. MACT Floor Methodology: Pollutant-by-Pollutant Approach	EPA-HQ-OAR-2002-0058-3504-A1	29	Florida Sugar Industry (FSI)	David A. Buff, Golder Associates Inc.
103D. MACT Floor Methodology: Pollutant-by-Pollutant Approach	EPA-HQ-OAR-2002-0058-3508-A1	6	United States Beet Sugar Association (USBSA)	James Johnson
103D. MACT Floor Methodology: Pollutant-by-Pollutant Approach	EPA-HQ-OAR-2002-0058-3510-A1	25	American Chemistry Council (ACC)	Lorraine Gershman

Table 2. Commenters that have submitted comments on topics addressed in section V of the preamble

Comment Topic	DCN	Comment Excerpt Number	Commenter Affiliation	Commenter Name
103D. MACT Floor Methodology: Pollutant-by-Pollutant Approach	EPA-HQ-OAR-2002-0058-3510-A1	74	American Chemistry Council (ACC)	Lorraine Gershman
103D. MACT Floor Methodology: Pollutant-by-Pollutant Approach	EPA-HQ-OAR-2002-0058-3515-A1	16	National Association of Manufacturers (NAM)	Alicia Meads
103D. MACT Floor Methodology: Pollutant-by-Pollutant Approach	EPA-HQ-OAR-2002-0058-3519-A1	11	National Alliance of Forest Owners (NAFO)	Roger Martella
103D. MACT Floor Methodology: Pollutant-by-Pollutant Approach	EPA-HQ-OAR-2002-0058-3522-A1	4	The Amalgamated Sugar Company LLC (TASCO)	Dean C. DeLorey
103D. MACT Floor Methodology: Pollutant-by-Pollutant Approach	EPA-HQ-OAR-2002-0058-3608-A1	14	Class of '85 Regulatory Response Group	Allison Watkins, Baker Botts
103D. MACT Floor Methodology: Pollutant-by-Pollutant Approach	EPA-HQ-OAR-2002-0058-3659-A2	13	Integrays Energy Group	Randal G. Oswald
103D. MACT Floor Methodology: Pollutant-by-Pollutant Approach	EPA-HQ-OAR-2002-0058-3685-A2	27	American Municipal Power	Douglas A. McWilliams
103D. MACT Floor Methodology: Pollutant-by-Pollutant Approach	EPA-HQ-OAR-2002-0058-3686-A2	6	Boise Inc.	Richard D. Garber
103E. MACT Floor Methodology: 3x RDL	EPA-HQ-OAR-2002-0058-3525-A1	6	National Association of Clean Air Agencies (NACAA)	Mary Sullivan Douglas
103H. MACT Floor Methodology: Exclusion of Co-Fired Data	EPA-HQ-OAR-2002-0058-3524-A1	1	CPI USA North Carolina (CPI NC)	Ahmed Idriss, Capital Power Corporation
103H. MACT Floor Methodology: Exclusion of Co-Fired Data	EPA-HQ-OAR-2002-0058-3525-A1	34	National Association of Clean Air Agencies (NACAA)	Mary Sullivan Douglas
103H. MACT Floor Methodology: Exclusion of Co-Fired Data	EPA-HQ-OAR-2002-0058-3669-A2	16	Eastman Chemical Company	Steve Gossett
103H. MACT Floor Methodology: Exclusion of Co-Fired Data	EPA-HQ-OAR-2002-0058-3691-A2	4	Maine Department of Environmental Protection	Heather Parent
104A. Remove Energy Assessment	EPA-HQ-OAR-2002-0058-3457-A2	12	AK Steel Corporation	Paul G. Page
104A. Remove Energy Assessment	EPA-HQ-OAR-2002-0058-3457-A2	16	AK Steel Corporation	Paul G. Page
104A. Remove Energy Assessment	EPA-HQ-OAR-2002-0058-3492-A1	12	Interstate Power and Light Company (IPL) and Wisconsin Power and Light Company (WPL), Alliant Energy Corp.	Eric Guelker, Alliant Energy Corporate Services, Inc.
104A. Remove Energy Assessment	EPA-HQ-OAR-2002-0058-3492-A1	13	Interstate Power and Light Company (IPL) and Wisconsin Power and Light Company (WPL), Alliant Energy Corp.	Eric Guelker, Alliant Energy Corporate Services, Inc.
104A. Remove Energy Assessment	EPA-HQ-OAR-2002-0058-3496-A1	3	United States Sugar Corporation	Kevin G. Desharnais, Attorney, Mayer Brown LLP

Table 2. Commenters that have submitted comments on topics addressed in section V of the preamble

Comment Topic	DCN	Comment Excerpt Number	Commenter Affiliation	Commenter Name
104A. Remove Energy Assessment	EPA-HQ-OAR-2002-0058-3500-A1	10	Utility Air Regulatory Group (UARG)	Lee Zeugin and Lauren Freeman
104A. Remove Energy Assessment	EPA-HQ-OAR-2002-0058-3504-A1	44	Florida Sugar Industry (FSI)	David A. Buff, Golder Associates Inc.
104A. Remove Energy Assessment	EPA-HQ-OAR-2002-0058-3510-A1	81	American Chemistry Council (ACC)	Lorraine Gershman
104A. Remove Energy Assessment	EPA-HQ-OAR-2002-0058-3510-A1	82	American Chemistry Council (ACC)	Lorraine Gershman
104A. Remove Energy Assessment	EPA-HQ-OAR-2002-0058-3512-A1	45	Auto Industry Forum (AIF)	Shannon S. Broome
104A. Remove Energy Assessment	EPA-HQ-OAR-2002-0058-3512-A1	47	Auto Industry Forum (AIF)	Shannon S. Broome
104A. Remove Energy Assessment	EPA-HQ-OAR-2002-0058-3523-A1	14	Weyerhaeuser Company	Stephen E. Woock
104A. Remove Energy Assessment	EPA-HQ-OAR-2002-0058-3524-A1	7	CPI USA North Carolina (CPI NC)	Ahmed Idriss, Capital Power Corporation
104A. Remove Energy Assessment	EPA-HQ-OAR-2002-0058-3534-A1	109	Council of Industrial Boiler Owners (CIBO)	Robert D. Bessette
104A. Remove Energy Assessment	EPA-HQ-OAR-2002-0058-3534-A1	112	Council of Industrial Boiler Owners (CIBO)	Robert D. Bessette
104A. Remove Energy Assessment	EPA-HQ-OAR-2002-0058-3547-A2	11	American Coke and Coal Chemical Institute (ACCCI)	Bruce A. Steiner
104A. Remove Energy Assessment	EPA-HQ-OAR-2002-0058-3547-A2	13	American Coke and Coal Chemical Institute (ACCCI)	Bruce A. Steiner
104A. Remove Energy Assessment	EPA-HQ-OAR-2002-0058-3547-A2	14	American Coke and Coal Chemical Institute (ACCCI)	Bruce A. Steiner
104A. Remove Energy Assessment	EPA-HQ-OAR-2002-0058-3594-A3	4	Texas Commission on Environmental Quality (TCEQ)	Tangela Niemann
104A. Remove Energy Assessment	EPA-HQ-OAR-2002-0058-3594-A3	5	Texas Commission on Environmental Quality (TCEQ)	Tangela Niemann
104A. Remove Energy Assessment	EPA-HQ-OAR-2002-0058-3608-A1	13	Class of '85 Regulatory Response Group	Allison Watkins, Baker Botts
104A. Remove Energy Assessment	EPA-HQ-OAR-2002-0058-3659-A2	9	Integrlys Energy Group	Randal G. Oswald
104A. Remove Energy Assessment	EPA-HQ-OAR-2002-0058-3659-A2	10	Integrlys Energy Group	Randal G. Oswald
104A. Remove Energy Assessment	EPA-HQ-OAR-2002-0058-3659-A2	12	Integrlys Energy Group	Randal G. Oswald
104A. Remove Energy Assessment	EPA-HQ-OAR-2002-0058-3677-A2	74	American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)	Matthew Todd
104A. Remove Energy Assessment	EPA-HQ-OAR-2002-0058-3755-A1	16	Alcoa Power Generating, Inc.	Samuel H. Bruntz
104B. Five Year Time Frame	EPA-HQ-OAR-2002-0058-3432-A1	7	Institute for Policy Integrity, NYU School of Law	Michael Livermore, Jason Schwartz
104B. Five Year Time Frame	EPA-HQ-OAR-2002-0058-3432-A1	10	Institute for Policy Integrity, NYU School of Law	Michael Livermore, Jason Schwartz
104B. Five Year Time Frame	EPA-HQ-OAR-2002-0058-3500-A1	9	Utility Air Regulatory Group (UARG)	Lee Zeugin and Lauren Freeman
104C. Cost Analysis	EPA-HQ-OAR-2002-0058-3501-A1	13	United States Clean Heat & Power Association (USCHPA)	Jessica Bridges

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Comment Topic	DCN	Comment Excerpt Number	Commenter Affiliation	Commenter Name
104C. Cost Analysis	EPA-HQ-OAR-2002-0058-3683-A2	6	The Alliance for Industrial Efficiency	David Gardiner
104D. Definition of “Cost Effective”	EPA-HQ-OAR-2002-0058-3432-A1	3	Institute for Policy Integrity, NYU School of Law	Michael Livermore, Jason Schwartz
104D. Definition of “Cost Effective”	EPA-HQ-OAR-2002-0058-3432-A1	4	Institute for Policy Integrity, NYU School of Law	Michael Livermore, Jason Schwartz
104D. Definition of “Cost Effective”	EPA-HQ-OAR-2002-0058-3432-A1	5	Institute for Policy Integrity, NYU School of Law	Michael Livermore, Jason Schwartz
104D. Definition of “Cost Effective”	EPA-HQ-OAR-2002-0058-3432-A1	6	Institute for Policy Integrity, NYU School of Law	Michael Livermore, Jason Schwartz
104D. Definition of “Cost Effective”	EPA-HQ-OAR-2002-0058-3432-A1	8	Institute for Policy Integrity, NYU School of Law	Michael Livermore, Jason Schwartz
104D. Definition of “Cost Effective”	EPA-HQ-OAR-2002-0058-3683-A2	5	The Alliance for Industrial Efficiency	David Gardiner
104E. Energy Assessors Determine Time	EPA-HQ-OAR-2002-0058-3594-A3	14	Texas Commission on Environmental Quality (TCEQ)	Tangela Niemann
107A01. Limited Use of Liquids in Gas 1 Units	EPA-HQ-OAR-2002-0058-3448-A1	2	The Fertilizer Institute (TFI)	William C. Herz
107A01. Limited Use of Liquids in Gas 1 Units	EPA-HQ-OAR-2002-0058-3449-A1	39	The Dow Chemical Company	Russell A. Wozniak
107A01. Limited Use of Liquids in Gas 1 Units	EPA-HQ-OAR-2002-0058-3503-A1	1	Rubber Manufacturers Association (RMA)	Sarah E. Amick
107A01. Limited Use of Liquids in Gas 1 Units	EPA-HQ-OAR-2002-0058-3510-A1	154	American Chemistry Council (ACC)	Lorraine Gershman
107A01. Limited Use of Liquids in Gas 1 Units	EPA-HQ-OAR-2002-0058-3510-A1	155	American Chemistry Council (ACC)	Lorraine Gershman
107A01. Limited Use of Liquids in Gas 1 Units	EPA-HQ-OAR-2002-0058-3512-A1	51	Auto Industry Forum (AIF)	Shannon S. Broome
107A01. Limited Use of Liquids in Gas 1 Units	EPA-HQ-OAR-2002-0058-3521-A1	127	American Forest & Paper Association (AF&PA) et al.	Paul Noe
107A01. Limited Use of Liquids in Gas 1 Units	EPA-HQ-OAR-2002-0058-3521-A1	128	American Forest & Paper Association (AF&PA) et al.	Paul Noe
107A01. Limited Use of Liquids in Gas 1 Units	EPA-HQ-OAR-2002-0058-3521-A1	129	American Forest & Paper Association (AF&PA) et al.	Paul Noe
107A01. Limited Use of Liquids in Gas 1 Units	EPA-HQ-OAR-2002-0058-3630-A2	3	Tesoro Companies, Inc	Douglas Price
107A01. Limited Use of Liquids in Gas 1 Units	EPA-HQ-OAR-2002-0058-3673-A2	3	HOVENSA LLC. , Hess Corporation	Christopher Coleman
107A01. Limited Use of Liquids in Gas 1 Units	EPA-HQ-OAR-2002-0058-3673-A2	4	HOVENSA LLC. , Hess Corporation	Christopher Coleman
107A01. Limited Use of Liquids in Gas 1 Units	EPA-HQ-OAR-2002-0058-3673-A2	5	HOVENSA LLC. , Hess Corporation	Christopher Coleman
107A01. Limited Use of Liquids in Gas 1 Units	EPA-HQ-OAR-2002-0058-3677-A2	28	American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)	Matthew Todd
107A01. Limited Use of Liquids in Gas 1 Units	EPA-HQ-OAR-2002-0058-3677-A2	29	American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)	Matthew Todd
107A02. Automatically Include Other Gases in Gas 1 Definition	EPA-HQ-OAR-2002-0058-3448-A1	8	The Fertilizer Institute (TFI)	William C. Herz
107A02. Automatically Include Other Gases in Gas 1 Definition	EPA-HQ-OAR-2002-0058-3448-A1	9	The Fertilizer Institute (TFI)	William C. Herz

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Comment Topic	DCN	Comment Excerpt Number	Commenter Affiliation	Commenter Name
107A02. Automatically Include Other Gases in Gas 1 Definition	EPA-HQ-OAR-2002-0058-3490-A1	17	American Iron and Steel Institute (AISI)	Peter Pagano
107A02. Automatically Include Other Gases in Gas 1 Definition	EPA-HQ-OAR-2002-0058-3512-A1	15	Auto Industry Forum (AIF)	Shannon S. Broome
107A02. Automatically Include Other Gases in Gas 1 Definition	EPA-HQ-OAR-2002-0058-3512-A1	16	Auto Industry Forum (AIF)	Shannon S. Broome
107A02. Automatically Include Other Gases in Gas 1 Definition	EPA-HQ-OAR-2002-0058-3512-A1	17	Auto Industry Forum (AIF)	Shannon S. Broome
107A02. Automatically Include Other Gases in Gas 1 Definition	EPA-HQ-OAR-2002-0058-3512-A1	18	Auto Industry Forum (AIF)	Shannon S. Broome
107A02. Automatically Include Other Gases in Gas 1 Definition	EPA-HQ-OAR-2002-0058-3526-A1	10	The Vinyl Institute	Richard Krock
107A02. Automatically Include Other Gases in Gas 1 Definition	EPA-HQ-OAR-2002-0058-3534-A1	9	Council of Industrial Boiler Owners (CIBO)	Robert D. Bessette
107A02. Automatically Include Other Gases in Gas 1 Definition	EPA-HQ-OAR-2002-0058-3534-A1	11	Council of Industrial Boiler Owners (CIBO)	Robert D. Bessette
107A02. Automatically Include Other Gases in Gas 1 Definition	EPA-HQ-OAR-2002-0058-3539-A1	4	National Solid Wastes Management Association (NSWMA)	Edward W. Repa
107A02. Automatically Include Other Gases in Gas 1 Definition	EPA-HQ-OAR-2002-0058-3539-A1	5	National Solid Wastes Management Association (NSWMA)	Edward W. Repa
107A02. Automatically Include Other Gases in Gas 1 Definition	EPA-HQ-OAR-2002-0058-3539-A1	8	National Solid Wastes Management Association (NSWMA)	Edward W. Repa
107A02. Automatically Include Other Gases in Gas 1 Definition	EPA-HQ-OAR-2002-0058-3545-A2	1	Delaware Solid Waste Authority (DSWA)	Angela D. Marconi
107A02. Automatically Include Other Gases in Gas 1 Definition	EPA-HQ-OAR-2002-0058-3681-A2	1	Waste Management (WM)	Kerry Kelly
107A02. Automatically Include Other Gases in Gas 1 Definition	EPA-HQ-OAR-2002-0058-3681-A2	2	Waste Management (WM)	Kerry Kelly
107A02. Automatically Include Other Gases in Gas 1 Definition	EPA-HQ-OAR-2002-0058-3681-A2	3	Waste Management (WM)	Kerry Kelly
107A02. Automatically Include Other Gases in Gas 1 Definition	EPA-HQ-OAR-2002-0058-3681-A2	4	Waste Management (WM)	Kerry Kelly
107A02. Automatically Include Other Gases in Gas 1 Definition	EPA-HQ-OAR-2002-0058-3681-A2	5	Waste Management (WM)	Kerry Kelly
107A02. Automatically Include Other Gases in Gas 1 Definition	EPA-HQ-OAR-2002-0058-3681-A2	6	Waste Management (WM)	Kerry Kelly
107A02. Automatically Include Other Gases in Gas 1 Definition	EPA-HQ-OAR-2002-0058-3681-A2	7	Waste Management (WM)	Kerry Kelly
107A02. Automatically Include Other Gases in Gas 1 Definition	EPA-HQ-OAR-2002-0058-3681-A2	8	Waste Management (WM)	Kerry Kelly
107A02. Automatically Include Other Gases in Gas 1 Definition	EPA-HQ-OAR-2002-0058-3689-A2	2	ConocoPhillips Company	Dan F. Hunter
107A02. Automatically Include Other Gases in Gas 1 Definition	EPA-HQ-OAR-2002-0058-3778-A1	5	PPG Industries, Inc	Elizabeth McMeekin
107A03. Re-Evaluate Gas 2 Subcategory	EPA-HQ-OAR-2002-0058-3490-A1	30	American Iron and Steel Institute (AISI)	Peter Pagano
107A03. Re-Evaluate Gas 2 Subcategory	EPA-HQ-OAR-2002-0058-3490-A1	31	American Iron and Steel Institute (AISI)	Peter Pagano
107A03. Re-Evaluate Gas 2 Subcategory	EPA-HQ-OAR-2002-0058-3547-A2	8	American Coke and Coal Chemical Institute (ACCCI)	Bruce A. Steiner
107A03. Re-Evaluate Gas 2 Subcategory	EPA-HQ-OAR-2002-0058-3547-A2	10	American Coke and Coal Chemical Institute (ACCCI)	Bruce A. Steiner

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Comment Topic	DCN	Comment Excerpt Number	Commenter Affiliation	Commenter Name
107A04. Metal Process Furnace Definition	EPA-HQ-OAR-2002-0058-3448-A1	1	The Fertilizer Institute (TFI)	William C. Herz
107A04. Metal Process Furnace Definition	EPA-HQ-OAR-2002-0058-3490-A1	11	American Iron and Steel Institute (AISI)	Peter Pagano
107A04. Metal Process Furnace Definition	EPA-HQ-OAR-2002-0058-3490-A1	12	American Iron and Steel Institute (AISI)	Peter Pagano
107A04. Metal Process Furnace Definition	EPA-HQ-OAR-2002-0058-3490-A1	14	American Iron and Steel Institute (AISI)	Peter Pagano
107B. Designed to Burn Subcategorization	EPA-HQ-OAR-2002-0058-3511-A1	1	Earthjustice, Clean Air Council, Partnership for Policy Integrity	James Pew
107B. Designed to Burn Subcategorization	EPA-HQ-OAR-2002-0058-3511-A1	6	Earthjustice, Clean Air Council, Partnership for Policy Integrity	James Pew
107B. Designed to Burn Subcategorization	EPA-HQ-OAR-2002-0058-3525-A1	14	National Association of Clean Air Agencies (NACAA)	Mary Sullivan Douglas
107B. Designed to Burn Subcategorization	EPA-HQ-OAR-2002-0058-3525-A1	33	National Association of Clean Air Agencies (NACAA)	Mary Sullivan Douglas
109A. Remove Emission Averaging 10% Penalty	EPA-HQ-OAR-2002-0058-3490-A1	34	American Iron and Steel Institute (AISI)	Peter Pagano
109A. Remove Emission Averaging 10% Penalty	EPA-HQ-OAR-2002-0058-3496-A1	12	United States Sugar Corporation	Kevin G. Desharnais, Attorney, Mayer Brown LLP
109A. Remove Emission Averaging 10% Penalty	EPA-HQ-OAR-2002-0058-3496-A1	13	United States Sugar Corporation	Kevin G. Desharnais, Attorney, Mayer Brown LLP
109A. Remove Emission Averaging 10% Penalty	EPA-HQ-OAR-2002-0058-3504-A1	59	Florida Sugar Industry (FSI)	David A. Buff, Golder Associates Inc.
109A. Remove Emission Averaging 10% Penalty	EPA-HQ-OAR-2002-0058-3510-A1	49	American Chemistry Council (ACC)	Lorraine Gershman
109A. Remove Emission Averaging 10% Penalty	EPA-HQ-OAR-2002-0058-3520-A1	12	Southern Company	Chris M. Hobson
109A. Remove Emission Averaging 10% Penalty	EPA-HQ-OAR-2002-0058-3521-A1	79	American Forest & Paper Association (AF&PA) et al.	Paul Noe
109A. Remove Emission Averaging 10% Penalty	EPA-HQ-OAR-2002-0058-3521-A1	92	American Forest & Paper Association (AF&PA) et al.	Paul Noe
109A. Remove Emission Averaging 10% Penalty	EPA-HQ-OAR-2002-0058-3661-A2	10	Masco Corporation	John M. Cullen
109A. Remove Emission Averaging 10% Penalty	EPA-HQ-OAR-2002-0058-3669-A2	48	Eastman Chemical Company	Steve Gossett
109A. Remove Emission Averaging 10% Penalty	EPA-HQ-OAR-2002-0058-3685-A2	44	American Municipal Power	Douglas A. McWilliams
109B. Allow Emission Averaging Across Subcategories	EPA-HQ-OAR-2002-0058-3490-A1	33	American Iron and Steel Institute (AISI)	Peter Pagano
109B. Allow Emission Averaging Across Subcategories	EPA-HQ-OAR-2002-0058-3490-A1	35	American Iron and Steel Institute (AISI)	Peter Pagano
109B. Allow Emission Averaging Across Subcategories	EPA-HQ-OAR-2002-0058-3492-A1	4	Interstate Power and Light Company (IPL) and Wisconsin Power and Light Company (WPL), Alliant Energy Corp.	Eric Guelker, Alliant Energy Corporate Services, Inc.
109B. Allow Emission Averaging Across Subcategories	EPA-HQ-OAR-2002-0058-3493-A1	13	MeadWestvaco Corporation (MWV)	Dirk J. Krouskop

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Comment Topic	DCN	Comment Excerpt Number	Commenter Affiliation	Commenter Name
109B. Allow Emission Averaging Across Subcategories	EPA-HQ-OAR-2002-0058-3502-A1	16	American Coatings Association (ACA)	Timothy Serie
109B. Allow Emission Averaging Across Subcategories	EPA-HQ-OAR-2002-0058-3510-A1	140	American Chemistry Council (ACC)	Lorraine Gershman
109B. Allow Emission Averaging Across Subcategories	EPA-HQ-OAR-2002-0058-3510-A1	141	American Chemistry Council (ACC)	Lorraine Gershman
109B. Allow Emission Averaging Across Subcategories	EPA-HQ-OAR-2002-0058-3510-A1	142	American Chemistry Council (ACC)	Lorraine Gershman
109B. Allow Emission Averaging Across Subcategories	EPA-HQ-OAR-2002-0058-3510-A1	143	American Chemistry Council (ACC)	Lorraine Gershman
109B. Allow Emission Averaging Across Subcategories	EPA-HQ-OAR-2002-0058-3521-A1	77	American Forest & Paper Association (AF&PA) et al.	Paul Noe
109B. Allow Emission Averaging Across Subcategories	EPA-HQ-OAR-2002-0058-3608-A1	9	Class of '85 Regulatory Response Group	Allison Watkins, Baker Botts
109B. Allow Emission Averaging Across Subcategories	EPA-HQ-OAR-2002-0058-3608-A1	11	Class of '85 Regulatory Response Group	Allison Watkins, Baker Botts
109B. Allow Emission Averaging Across Subcategories	EPA-HQ-OAR-2002-0058-3669-A2	40	Eastman Chemical Company	Steve Gossett
109B. Allow Emission Averaging Across Subcategories	EPA-HQ-OAR-2002-0058-3669-A2	44	Eastman Chemical Company	Steve Gossett
109B. Allow Emission Averaging Across Subcategories	EPA-HQ-OAR-2002-0058-3669-A2	45	Eastman Chemical Company	Steve Gossett
109B. Allow Emission Averaging Across Subcategories	EPA-HQ-OAR-2002-0058-3669-A2	46	Eastman Chemical Company	Steve Gossett
110A. Testing Frequency	EPA-HQ-OAR-2002-0058-3449-A1	19	The Dow Chemical Company	Russell A. Wozniak
110A. Testing Frequency	EPA-HQ-OAR-2002-0058-3451-A1	6	Georgia Paper & Forest Products Association	Randall D. Quintrell
110A. Testing Frequency	EPA-HQ-OAR-2002-0058-3485-A1	14	JELD-WEN, inc.	Claudia M. O'Brien, Latham & Watkins LLP
110A. Testing Frequency	EPA-HQ-OAR-2002-0058-3485-A1	15	JELD-WEN, inc.	Claudia M. O'Brien, Latham & Watkins LLP
110A. Testing Frequency	EPA-HQ-OAR-2002-0058-3506-A1	22	Northeast States for Coordinated Air Use Management (NESCAUM)	Arthur N. Marin
110A. Testing Frequency	EPA-HQ-OAR-2002-0058-3507-A1	20	Pennsylvania Department of Environmental Protection (DEP)	Michael L. Krancer
110A. Testing Frequency	EPA-HQ-OAR-2002-0058-3510-A1	134	American Chemistry Council (ACC)	Lorraine Gershman
110A. Testing Frequency	EPA-HQ-OAR-2002-0058-3521-A1	112	American Forest & Paper Association (AF&PA) et al.	Paul Noe
110A. Testing Frequency	EPA-HQ-OAR-2002-0058-3523-A1	16	Weyerhaeuser Company	Stephen E. Woock
110A. Testing Frequency	EPA-HQ-OAR-2002-0058-3527-A1	4	Wisconsin Department of Natural Resources (DNR)	Bart Sponsellar
110A. Testing Frequency	EPA-HQ-OAR-2002-0058-3527-A2	26	Wisconsin Department of Natural Resources	Bart Sponsellar
110A. Testing Frequency	EPA-HQ-OAR-2002-0058-3534-A1	95	Council of Industrial Boiler Owners (CIBO)	Robert D. Bessette
110A. Testing Frequency	EPA-HQ-OAR-2002-0058-3534-A1	97	Council of Industrial Boiler Owners (CIBO)	Robert D. Bessette
110A. Testing Frequency	EPA-HQ-OAR-2002-0058-3537-A2	1	Verso Paper Corp.	Sarah Hedrick

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Comment Topic	DCN	Comment Excerpt Number	Commenter Affiliation	Commenter Name
110A. Testing Frequency	EPA-HQ-OAR-2002-0058-3664-A2	3	New Jersey Department of Environmental Protection (NJDEP)	Linda Miller
110A. Testing Frequency	EPA-HQ-OAR-2002-0058-3668-A2	18	Purdue University	Robin Mills Ridgway
110A. Testing Frequency	EPA-HQ-OAR-2002-0058-3670-A2	6	Archer Daniels Midland Company	Pat Dennis
110A. Testing Frequency	EPA-HQ-OAR-2002-0058-3670-A2	7	Archer Daniels Midland Company	Pat Dennis
110A. Testing Frequency	EPA-HQ-OAR-2002-0058-3670-A2	8	Archer Daniels Midland Company	Pat Dennis
110A. Testing Frequency	EPA-HQ-OAR-2002-0058-3676-A2	10	American Home Furnishings Alliance (AHFA)	Bill Lane
110A. Testing Frequency	EPA-HQ-OAR-2002-0058-3677-A2	99	American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)	Matthew Todd
110A. Testing Frequency	EPA-HQ-OAR-2002-0058-3677-A2	101	American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)	Matthew Todd
110B. Operating Load Limits During Testing	EPA-HQ-OAR-2002-0058-3466-A1	8	Maine Pulp & Paper Association (MPPA)	John S Williams
110B. Operating Load Limits During Testing	EPA-HQ-OAR-2002-0058-3466-A1	9	Maine Pulp & Paper Association (MPPA)	John S Williams
110B. Operating Load Limits During Testing	EPA-HQ-OAR-2002-0058-3466-A1	10	Maine Pulp & Paper Association (MPPA)	John S Williams
110B. Operating Load Limits During Testing	EPA-HQ-OAR-2002-0058-3485-A1	7	JELD-WEN, inc.	Claudia M. O'Brien, Latham & Watkins LLP
110B. Operating Load Limits During Testing	EPA-HQ-OAR-2002-0058-3504-A1	39	Florida Sugar Industry (FSI)	David A. Buff, Golder Associates Inc.
110B. Operating Load Limits During Testing	EPA-HQ-OAR-2002-0058-3677-A2	123	American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)	Matthew Todd
110B. Operating Load Limits During Testing	EPA-HQ-OAR-2002-0058-3691-A2	9	Maine Department of Environmental Protection	Heather Parent
110C01. Fuel Sampling Procedures	EPA-HQ-OAR-2002-0058-3677-A2	117	American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)	Matthew Todd
110C02. Reduce Fuel Analysis Burden	EPA-HQ-OAR-2002-0058-3453-A1	2	FMC Corporation	Michael D. Wendorf
110C02. Reduce Fuel Analysis Burden	EPA-HQ-OAR-2002-0058-3453-A1	3	FMC Corporation	Michael D. Wendorf
110C02. Reduce Fuel Analysis Burden	EPA-HQ-OAR-2002-0058-3503-A1	16	Rubber Manufacturers Association (RMA)	Sarah E. Amick
110C02. Reduce Fuel Analysis Burden	EPA-HQ-OAR-2002-0058-3520-A1	11	Southern Company	Chris M. Hobson
110C02. Reduce Fuel Analysis Burden	EPA-HQ-OAR-2002-0058-3521-A1	111	American Forest & Paper Association (AF&PA) et al.	Paul Noe
110C02. Reduce Fuel Analysis Burden	EPA-HQ-OAR-2002-0058-3521-A1	116	American Forest & Paper Association (AF&PA) et al.	Paul Noe
110C02. Reduce Fuel Analysis Burden	EPA-HQ-OAR-2002-0058-3537-A2	4	Verso Paper Corp.	Sarah Hedrick

Table 2. Commenters that have submitted comments on topics addressed in section V of the preamble

Comment Topic	DCN	Comment Excerpt Number	Commenter Affiliation	Commenter Name
110C02. Reduce Fuel Analysis Burden	EPA-HQ-OAR-2002-0058-3676-A2	11	American Home Furnishings Alliance (AHFA)	Bill Lane
110C02. Reduce Fuel Analysis Burden	EPA-HQ-OAR-2002-0058-3676-A2	12	American Home Furnishings Alliance (AHFA)	Bill Lane
110C02. Reduce Fuel Analysis Burden	EPA-HQ-OAR-2002-0058-3677-A2	102	American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)	Matthew Todd
110C02. Reduce Fuel Analysis Burden	EPA-HQ-OAR-2002-0058-3685-A2	35	American Municipal Power	Douglas A. McWilliams
110C02. Reduce Fuel Analysis Burden	EPA-HQ-OAR-2002-0058-3755-A1	8	Alcoa Power Generating, Inc.	Samuel H. Bruntz
110C02. Reduce Fuel Analysis Burden	EPA-HQ-OAR-2002-0058-3814-A1	16	CraftMaster Manufacturing, Inc.	M.L. Steele
110C02. Reduce Fuel Analysis Burden	EPA-HQ-OAR-2002-0058-3814-A1	18	CraftMaster Manufacturing, Inc.	M.L. Steele
111B02. Use Consistent Averaging Times for Initial and Continuous Compliance	EPA-HQ-OAR-2002-0058-3511-A1	26	Earthjustice, Clean Air Council, Partnership for Policy Integrity	James Pew
111B02. Use Consistent Averaging Times for Initial and Continuous Compliance	EPA-HQ-OAR-2002-0058-3525-A1	21	National Association of Clean Air Agencies (NACAA)	Mary Sullivan Douglas
111B03. Deviation Definition	EPA-HQ-OAR-2002-0058-3500-A1	30	Utility Air Regulatory Group (UARG)	Lee Zeugin and Lauren Freeman
111B03. Deviation Definition	EPA-HQ-OAR-2002-0058-3500-A1	31	Utility Air Regulatory Group (UARG)	Lee Zeugin and Lauren Freeman
111C01. Pressure Monitoring Taps	EPA-HQ-OAR-2002-0058-3755-A1	9	Alcoa Power Generating, Inc.	Samuel H. Bruntz
111C02. Revise Max/Min Operating Parameter Language	EPA-HQ-OAR-2002-0058-3500-A1	34	Utility Air Regulatory Group (UARG)	Lee Zeugin and Lauren Freeman
111C02. Revise Max/Min Operating Parameter Language	EPA-HQ-OAR-2002-0058-3500-A1	35	Utility Air Regulatory Group (UARG)	Lee Zeugin and Lauren Freeman
111C02. Revise Max/Min Operating Parameter Language	EPA-HQ-OAR-2002-0058-3500-A1	36	Utility Air Regulatory Group (UARG)	Lee Zeugin and Lauren Freeman
111C02. Revise Max/Min Operating Parameter Language	EPA-HQ-OAR-2002-0058-3500-A1	37	Utility Air Regulatory Group (UARG)	Lee Zeugin and Lauren Freeman
111C02. Revise Max/Min Operating Parameter Language	EPA-HQ-OAR-2002-0058-3500-A1	38	Utility Air Regulatory Group (UARG)	Lee Zeugin and Lauren Freeman
111C02. Revise Max/Min Operating Parameter Language	EPA-HQ-OAR-2002-0058-3500-A1	49	Utility Air Regulatory Group (UARG)	Lee Zeugin and Lauren Freeman
111C02. Revise Max/Min Operating Parameter Language	EPA-HQ-OAR-2002-0058-3500-A1	50	Utility Air Regulatory Group (UARG)	Lee Zeugin and Lauren Freeman
111C02. Revise Max/Min Operating Parameter Language	EPA-HQ-OAR-2002-0058-3500-A1	51	Utility Air Regulatory Group (UARG)	Lee Zeugin and Lauren Freeman
111C02. Revise Max/Min Operating Parameter Language	EPA-HQ-OAR-2002-0058-3500-A1	52	Utility Air Regulatory Group (UARG)	Lee Zeugin and Lauren Freeman
111C02. Revise Max/Min Operating Parameter Language	EPA-HQ-OAR-2002-0058-3500-A1	53	Utility Air Regulatory Group (UARG)	Lee Zeugin and Lauren Freeman
111C02. Revise Max/Min Operating Parameter Language	EPA-HQ-OAR-2002-0058-3500-A1	54	Utility Air Regulatory Group (UARG)	Lee Zeugin and Lauren Freeman
111C02. Revise Max/Min Operating Parameter Language	EPA-HQ-OAR-2002-0058-3500-A1	55	Utility Air Regulatory Group (UARG)	Lee Zeugin and Lauren Freeman
111C02. Revise Max/Min Operating Parameter Language	EPA-HQ-OAR-2002-0058-3500-A1	56	Utility Air Regulatory Group (UARG)	Lee Zeugin and Lauren Freeman
111C02. Revise Max/Min Operating Parameter Language	EPA-HQ-OAR-2002-0058-3500-A1	57	Utility Air Regulatory Group (UARG)	Lee Zeugin and Lauren Freeman

Table 2. Commenters that have submitted comments on topics addressed in section V of the preamble

Comment Topic	DCN	Comment Excerpt Number	Commenter Affiliation	Commenter Name
111C02. Revise Max/Min Operating Parameter Language	EPA-HQ-OAR-2002-0058-3500-A1	58	Utility Air Regulatory Group (UARG)	Lee Zeugin and Lauren Freeman
111C02. Revise Max/Min Operating Parameter Language	EPA-HQ-OAR-2002-0058-3500-A1	60	Utility Air Regulatory Group (UARG)	Lee Zeugin and Lauren Freeman
111C02. Revise Max/Min Operating Parameter Language	EPA-HQ-OAR-2002-0058-3510-A1	59	American Chemistry Council (ACC)	Lorraine Gershman
111C02. Revise Max/Min Operating Parameter Language	EPA-HQ-OAR-2002-0058-3510-A1	60	American Chemistry Council (ACC)	Lorraine Gershman
111C02. Revise Max/Min Operating Parameter Language	EPA-HQ-OAR-2002-0058-3510-A1	61	American Chemistry Council (ACC)	Lorraine Gershman
111C02. Revise Max/Min Operating Parameter Language	EPA-HQ-OAR-2002-0058-3510-A1	62	American Chemistry Council (ACC)	Lorraine Gershman
111C02. Revise Max/Min Operating Parameter Language	EPA-HQ-OAR-2002-0058-3510-A1	63	American Chemistry Council (ACC)	Lorraine Gershman
111C02. Revise Max/Min Operating Parameter Language	EPA-HQ-OAR-2002-0058-3520-A1	10	Southern Company	Chris M. Hobson
111C02. Revise Max/Min Operating Parameter Language	EPA-HQ-OAR-2002-0058-3524-A1	9	CPI USA North Carolina (CPI NC)	Ahmed Idriss, Capital Power Corporation
111C02. Revise Max/Min Operating Parameter Language	EPA-HQ-OAR-2002-0058-3534-A1	100	Council of Industrial Boiler Owners (CIBO)	Robert D. Bessette
111C02. Revise Max/Min Operating Parameter Language	EPA-HQ-OAR-2002-0058-3534-A1	101	Council of Industrial Boiler Owners (CIBO)	Robert D. Bessette
111C02. Revise Max/Min Operating Parameter Language	EPA-HQ-OAR-2002-0058-3534-A1	102	Council of Industrial Boiler Owners (CIBO)	Robert D. Bessette
111C02. Revise Max/Min Operating Parameter Language	EPA-HQ-OAR-2002-0058-3543-A1	9	Duke Energy	J. Michael Geers
111C02. Revise Max/Min Operating Parameter Language	EPA-HQ-OAR-2002-0058-3543-A1	10	Duke Energy	J. Michael Geers
111C02. Revise Max/Min Operating Parameter Language	EPA-HQ-OAR-2002-0058-3543-A1	11	Duke Energy	J. Michael Geers
111C02. Revise Max/Min Operating Parameter Language	EPA-HQ-OAR-2002-0058-3543-A1	12	Duke Energy	J. Michael Geers
111C02. Revise Max/Min Operating Parameter Language	EPA-HQ-OAR-2002-0058-3543-A1	13	Duke Energy	J. Michael Geers
111C02. Revise Max/Min Operating Parameter Language	EPA-HQ-OAR-2002-0058-3543-A1	14	Duke Energy	J. Michael Geers
111C02. Revise Max/Min Operating Parameter Language	EPA-HQ-OAR-2002-0058-3543-A1	15	Duke Energy	J. Michael Geers
111C02. Revise Max/Min Operating Parameter Language	EPA-HQ-OAR-2002-0058-3543-A1	16	Duke Energy	J. Michael Geers
111C02. Revise Max/Min Operating Parameter Language	EPA-HQ-OAR-2002-0058-3543-A1	17	Duke Energy	J. Michael Geers
111C02. Revise Max/Min Operating Parameter Language	EPA-HQ-OAR-2002-0058-3668-A2	15	Purdue University	Robin Mills Ridgway
111C02. Revise Max/Min Operating Parameter Language	EPA-HQ-OAR-2002-0058-3677-A2	104	American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)	Matthew Todd
111C02. Revise Max/Min Operating Parameter Language	EPA-HQ-OAR-2002-0058-3685-A2	40	American Municipal Power	Douglas A. McWilliams
111C02. Revise Max/Min Operating Parameter Language	EPA-HQ-OAR-2002-0058-3814-A1	17	CraftMaster Manufacturing, Inc.	M.L. Steele
112A. Allow Health-Based Compliance Alternatives for HCl, Mn, and Acid Gases	EPA-HQ-OAR-2002-0058-3451-A1	2	Georgia Paper & Forest Products Association	Randall D. Quintrell

Table 2. Commenters that have submitted comments on topics addressed in section V of the preamble

Comment Topic	DCN	Comment Excerpt Number	Commenter Affiliation	Commenter Name
112A. Allow Health-Based Compliance Alternatives for HCl, Mn, and Acid Gases	EPA-HQ-OAR-2002-0058-3490-A1	37	American Iron and Steel Institute (AISI)	Peter Pagano
112A. Allow Health-Based Compliance Alternatives for HCl, Mn, and Acid Gases	EPA-HQ-OAR-2002-0058-3519-A1	9	National Alliance of Forest Owners (NAFO)	Roger Martella
112A. Allow Health-Based Compliance Alternatives for HCl, Mn, and Acid Gases	EPA-HQ-OAR-2002-0058-3523-A1	12	Weyerhaeuser Company	Stephen E. Woock
112A. Allow Health-Based Compliance Alternatives for HCl, Mn, and Acid Gases	EPA-HQ-OAR-2002-0058-3685-A2	1	American Municipal Power	Douglas A. McWilliams
112A. Allow Health-Based Compliance Alternatives for HCl, Mn, and Acid Gases	EPA-HQ-OAR-2002-0058-3685-A2	2	American Municipal Power	Douglas A. McWilliams
112A. Allow Health-Based Compliance Alternatives for HCl, Mn, and Acid Gases	EPA-HQ-OAR-2002-0058-3685-A2	4	American Municipal Power	Douglas A. McWilliams
112A. Allow Health-Based Compliance Alternatives for HCl, Mn, and Acid Gases	EPA-HQ-OAR-2002-0058-3685-A2	5	American Municipal Power	Douglas A. McWilliams
112A. Allow Health-Based Compliance Alternatives for HCl, Mn, and Acid Gases	EPA-HQ-OAR-2002-0058-3685-A2	7	American Municipal Power	Douglas A. McWilliams
112A. Allow Health-Based Compliance Alternatives for HCl, Mn, and Acid Gases	EPA-HQ-OAR-2002-0058-3691-A2	13	Maine Department of Environmental Protection	Heather Parent
114A. Definition of Natural Gas Curtailment	EPA-HQ-OAR-2002-0058-3449-A1	31	The Dow Chemical Company	Russell A. Wozniak
114A. Definition of Natural Gas Curtailment	EPA-HQ-OAR-2002-0058-3502-A1	15	American Coatings Association (ACA)	Timothy Serie
114A. Definition of Natural Gas Curtailment	EPA-HQ-OAR-2002-0058-3510-A1	144	American Chemistry Council (ACC)	Lorraine Gershman
114A. Definition of Natural Gas Curtailment	EPA-HQ-OAR-2002-0058-3510-A1	145	American Chemistry Council (ACC)	Lorraine Gershman
114A. Definition of Natural Gas Curtailment	EPA-HQ-OAR-2002-0058-3521-A1	123	American Forest & Paper Association (AF&PA) et al.	Paul Noe
114A. Definition of Natural Gas Curtailment	EPA-HQ-OAR-2002-0058-3521-A1	124	American Forest & Paper Association (AF&PA) et al.	Paul Noe
114A. Definition of Natural Gas Curtailment	EPA-HQ-OAR-2002-0058-3521-A1	125	American Forest & Paper Association (AF&PA) et al.	Paul Noe
114A. Definition of Natural Gas Curtailment	EPA-HQ-OAR-2002-0058-3521-A1	126	American Forest & Paper Association (AF&PA) et al.	Paul Noe
114A. Definition of Natural Gas Curtailment	EPA-HQ-OAR-2002-0058-3534-A1	61	Council of Industrial Boiler Owners (CIBO)	Robert D. Bessette
114A. Definition of Natural Gas Curtailment	EPA-HQ-OAR-2002-0058-3534-A1	62	Council of Industrial Boiler Owners (CIBO)	Robert D. Bessette
114A. Definition of Natural Gas Curtailment	EPA-HQ-OAR-2002-0058-3534-A1	63	Council of Industrial Boiler Owners (CIBO)	Robert D. Bessette
114A. Definition of Natural Gas Curtailment	EPA-HQ-OAR-2002-0058-3534-A1	64	Council of Industrial Boiler Owners (CIBO)	Robert D. Bessette
114A. Definition of Natural Gas Curtailment	EPA-HQ-OAR-2002-0058-3534-A1	65	Council of Industrial Boiler Owners (CIBO)	Robert D. Bessette

Table 2. Commenters that have submitted comments on topics addressed in section V of the preamble

Comment Topic	DCN	Comment Excerpt Number	Commenter Affiliation	Commenter Name
114A. Definition of Natural Gas Curtailment	EPA-HQ-OAR-2002-0058-3677-A2	31	American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)	Matthew Todd
114A. Definition of Natural Gas Curtailment	EPA-HQ-OAR-2002-0058-3677-A2	32	American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)	Matthew Todd
114A. Definition of Natural Gas Curtailment	EPA-HQ-OAR-2002-0058-3677-A2	33	American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)	Matthew Todd
115B. Electronic Reporting: WebFIRE	EPA-HQ-OAR-2002-0058-3500-A1	44	Utility Air Regulatory Group (UARG)	Lee Zeugin and Lauren Freeman
115B. Electronic Reporting: WebFIRE	EPA-HQ-OAR-2002-0058-3500-A1	46	Utility Air Regulatory Group (UARG)	Lee Zeugin and Lauren Freeman
115B. Electronic Reporting: WebFIRE	EPA-HQ-OAR-2002-0058-3500-A1	47	Utility Air Regulatory Group (UARG)	Lee Zeugin and Lauren Freeman
115B. Electronic Reporting: WebFIRE	EPA-HQ-OAR-2002-0058-3500-A1	48	Utility Air Regulatory Group (UARG)	Lee Zeugin and Lauren Freeman
115B. Electronic Reporting: WebFIRE	EPA-HQ-OAR-2002-0058-3629-A2	7	South Carolina Department of Health and Environmental Control	Myra Reece
115B. Electronic Reporting: WebFIRE	EPA-HQ-OAR-2002-0058-3668-A2	19	Purdue University	Robin Mills Ridgway
115B. Electronic Reporting: WebFIRE	EPA-HQ-OAR-2002-0058-3677-A2	139	American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)	Matthew Todd
115B. Electronic Reporting: WebFIRE	EPA-HQ-OAR-2002-0058-3677-A2	140	American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)	Matthew Todd
115B. Electronic Reporting: WebFIRE	EPA-HQ-OAR-2002-0058-3677-A2	142	American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)	Matthew Todd
115B. Electronic Reporting: WebFIRE	EPA-HQ-OAR-2002-0058-3679-A2	15	American Lung Association	Janice E. Nolen
115B. Electronic Reporting: WebFIRE	EPA-HQ-OAR-2002-0058-3679-A2	16	American Lung Association	Janice E. Nolen
115C. Modify Gas Curtailment Notifications	EPA-HQ-OAR-2002-0058-3510-A1	146	American Chemistry Council (ACC)	Lorraine Gershman
115C. Modify Gas Curtailment Notifications	EPA-HQ-OAR-2002-0058-3512-A1	42	Auto Industry Forum (AIF)	Shannon S. Broome
115C. Modify Gas Curtailment Notifications	EPA-HQ-OAR-2002-0058-3512-A1	43	Auto Industry Forum (AIF)	Shannon S. Broome
115C. Modify Gas Curtailment Notifications	EPA-HQ-OAR-2002-0058-3512-A1	44	Auto Industry Forum (AIF)	Shannon S. Broome
115C. Modify Gas Curtailment Notifications	EPA-HQ-OAR-2002-0058-3521-A1	140	American Forest & Paper Association (AF&PA) et al.	Paul Noe
115C. Modify Gas Curtailment Notifications	EPA-HQ-OAR-2002-0058-3546-A2	1	Merck and Co., Inc	Barbara Schulze

Table 3. Form letters submitted to EPA-HQ-OAR-2002-0058

Form Letter Group	DCN:
National Council for Air and Stream Improvement (NCASI) (2)	EPA-HQ-OAR-2002-0058-3465-A1
National Council for Air and Stream Improvement (NCASI) (2)	EPA-HQ-OAR-2002-0058-3505-A1
Maine Pulp and Paper Association (2)	EPA-HQ-OAR-2002-0058-3466-A1
Maine Pulp and Paper Association (2)	EPA-HQ-OAR-2002-0058-3537-A2
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3441-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3443-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3445-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3446-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3447-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3458-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3459-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3461-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3462-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3463-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3464-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3468-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3469-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3470-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3475-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3481-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3482-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3483-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3484-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3554-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3555-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3556-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3557-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3558-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3560-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3561-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3562-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3563-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3564-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3565-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3566-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3567-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3568-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3569-A1

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Form Letter Group	DCN:
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3570-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3571-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3572-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3573-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3574-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3575-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3576-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3577-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3578-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3579-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3580-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3581-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3582-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3583-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3584-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3585-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3586-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3587-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3588-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3589-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3590-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3591-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3592-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3593-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3597-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3598-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3599-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3600-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3601-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3602-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3603-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3604-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3605-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3606-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3607-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3609-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3610-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3611-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3612-A1

Table 3. Form letters submitted to EPA-HQ-OAR-2002-0058

Form Letter Group	DCN:
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3613-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3614-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3615-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3616-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3617-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3618-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3619-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3620-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3621-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3622-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3623-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3624
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3625-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3626-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3631-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3632-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3633-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3634-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3635-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3636-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3637-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3638-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3639-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3640-A1
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Table 3. Form letters submitted to EPA-HQ-OAR-2002-0058

Form Letter Group	DCN:
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American Lung Association (220)	EPA-HQ-OAR-2002-0058-3697-A1
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American Lung Association (220)	EPA-HQ-OAR-2002-0058-3729-A1
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Table 3. Form letters submitted to EPA-HQ-OAR-2002-0058

Form Letter Group	DCN:
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Table 3. Form letters submitted to EPA-HQ-OAR-2002-0058

Form Letter Group	DCN:
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American Lung Association (220)	EPA-HQ-OAR-2002-0058-3820-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3821-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3822-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3823-A1
American Lung Association (220)	EPA-HQ-OAR-2002-0058-3824-A1

APPENDIX A: Out of Scope Comments on Other Related Rules

1A. Out of Scope: Non-Hazardous Solid Waste Definition

Commenter Name: Randall D. Quintrell

Commenter Affiliation: Georgia Paper & Forest Products Association

Document Control Number: EPA-HQ-OAR-2002-0058-3451-A1

Comment Excerpt Number: 19

Comment: Our comments on the NHSM rule are brief. As with the Boiler MACT reproposal, we fully support the comments submitted by AF&PA, NCASI, and individual member companies of GPFPA, and include them by reference as part of our comments here.

First and foremost, the underlying principal in any consideration of a waste and non-waste is the concept of "discard", a concept clearly laid out in RCRA. If a secondary material is not discarded, even though it may be used or reused for a secondary purpose, it is not a waste. The rule could be that simple! The angst that has been caused by the current NHSM rule and reproposal, which served to muddy the waters so much that many facilities do not yet know whether or not their units are boilers or CISWI units, is unnecessary.

Non-discarded materials commonly used as fuels include, but are not limited to, recycled paper rejects (e.g., *ace* rejects), wastewater residuals, broken and scrap paper that is not recyclable, pulping residuals, sawdust and wood trim (resinated and non-resinated), and off-spec product. Each of these materials has value as fuel and is being used to offset the use of fossil fuels, thus reducing costs, greenhouse gas emissions, and dependence on foreign oil. As such, the use of these materials as fuel furthers the goals of other EPA, and DOE, programs. Facilities should not have to "prove" that a useful, non-discarded material is a non-waste; rather a material that is not discarded and is used on site, or that is purchased and treated as a commodity regardless of what it is, should be presumed to be a non-waste, and only if certain conditions are met, should there be any question about its status as a non-waste or waste. For example if a source pays an operator to have a material burned for it, then the value as a fuel would appear to be insufficient for commerce and the burning might be disposal; that circumstance could be a condition for a "waste" classification.

EPA should expand its list of non-waste materials to include all the materials mentioned above, as well as other materials commonly used as fuels in other industries, to include all materials that are currently and/or have historically been used as fuels, and EPA should revise its proposed approach from materials being presumptive waste with the facility having to prove differently. To do otherwise will unavoidably relegate useful fuels to the "waste" category and will necessarily require that these be replaced with either a fossil fuel or other biomass fuel, increasing operating costs with no benefit to the environment.

Response: This comment pertains to the Identification of Non-Hazardous Materials That Are Solid Waste and it is out of scope for this boiler rulemaking. Provided the commenter has submitted this comment to the Identification of Non-Hazardous Materials That Are Solid Waste rulemaking docket, the response to this comment will be provided there.

Commenter Name: John S Williams
Commenter Affiliation: Maine Pulp & Paper Association (MPPA)
Document Control Number: EPA-HQ-OAR-2002-0058-3466-A1
Comment Excerpt Number: 2

Comment: Many of the Maine Mills operate multi-fuel boilers to provide steam for processes. The Mills have undertaken great efforts to recover the heat value of a wide variety of secondary materials in these boilers. For example, most of the Mills burn WWTR from their wastewater treatment facilities, waste paper, cardboard and tire-derived fuel- all of which serve to displace a commensurate amount of biomass wood chips and/or fossil fuels, and preserve landfill capacity. EPA's definition of non-hazardous secondary materials, even with the proposed amendments, may jeopardize the Maine Mills' ability to continue to beneficially reuse these types of materials as fuels in these units unless they comply with the more stringent CISWI standards.

Response: This comment pertains to the Identification of Non-Hazardous Materials That Are Solid Waste and it is out of scope for this boiler rulemaking. Provided the commenter has submitted this comment to the Identification of Non-Hazardous Materials That Are Solid Waste rulemaking docket, the response to this comment will be provided there.

Commenter Name: John S Williams
Commenter Affiliation: Maine Pulp & Paper Association (MPPA)
Document Control Number: EPA-HQ-OAR-2002-0058-3466-A1
Comment Excerpt Number: 3

Comment: MPPA appreciates that EPA has acknowledged that on a mill-by-mill basis, WWTR probably meets the legitimacy criteria and can be managed as a non-waste fuel. However, there remains a lack of certainty in this status. To clarify the issue, MPPA and its members urge EPA to list pulp and paper mill wastewater treatment plant residuals categorically as a non-waste. Most Maine Mills operate boilers that are specifically designed to handle a variety of fuels; few boilers are designed to burn just traditional fuel. Over the years, the industry has recognized the benefit of burning secondary materials - particularly those generated on-site- because they are derived from on-site processes and many have characteristics similar to traditional fuel, particularly the biomass used to produce pulp and paper products.

Mills do not usually burn just one type of fuel at any one time. Bark and biomass fuel may be the primary fuel, but it is supplemented by others -- both traditional and alternative. This is done in order to meet the energy needs of the mill - but also to address best management of the boiler as well as air quality requirements. If the biomass fuel is wet, a boiler may need to burn more fossil fuels or alternative fuels with high heat content to boost heat value; if the boiler is burning too hot, the addition of fuel WWTR enables the mill to regulate temperature and improve combustion.

WWTR may also be burned because it has the best fuel value for the price. All of these decisions are based on the cost of energy and the energy demand of the mill at the time. Boiler conditions, fuel availability, energy needs, air quality requirements, as well as costs are all considered when the energy manager and boiler operators determine the right mix of fuel to burn on any given day.

As a result, the quantities of different types of fuels burned over the course of a year differ. This means that the mill may not burn 100 percent of the available fuel generated during that year. Not all WWTR can be burned. Not all biomass fuel can be burned. The fact that only a percentage of a secondary material generated by the industry is used for fuel does not negate its value as fuel. It reflects the realities of running a boiler where economic and operating conditions change from day to day, even hour to hour.

EPA needs to clarify that the Mill's WWTR may be fired in mill boilers without triggering applicability of CIS WI. Secondary materials have been an important alternative fuel used safely by the Maine mills for many years. In fact, most of the Maine mills' multi-fuel boilers, their fuel handling equipment, mill wastewater treatment systems and other ancillary equipment were designed to combust these fuels, particularly WWTR. Use of these fuels reduces reliance on purchased biomass and/or fossil fuels and provides an avenue to beneficially reuse the materials. In light of the greater stringency of the CISWI regulation, mills are likely to landfill these materials instead of recovering their fuel value if these materials are considered solid waste for purposes of Boiler MACT/CISWI. The cost to the Maine mills to dispose of these materials and to replace the heat value with natural biomass or fossil fuels would be in the tens of millions of dollars. B. Responses to EPA's Questions Concerning WWTR.

In the preamble (p 80484), EPA raises a number of questions concerning the management of the pulp and paper mill WWTR and asks for additional information about the amount and contamination of the WWTR. The MPP A Mills offer the following responses.

1. How is WWTR used as fuel integrated into the industrial production process?

As described above, the energy manager at a mill will determine the approximate amount of different types of fuels needed to obtain the most energy under the best operating conditions. WWTR solids are generated through a dewatering process, then handled and stored in segregated areas to prevent contamination; it is directed toward the biomass fuel piles using loaders or directly to combustion using dedicated fuel handling and conveying equipment, or towards other uses. This decision is based on whether the mill's boiler is designed and permitted to burn WWTR and the amount is determined by the energy demands on that particular day.

2. Steps taken industry-wide to ensure that WWTR is consistently used as a legitimate fuel and is not discarded.

Just as mills do not use all of the same traditional fuel, mills do not always use WWTR as a fuel. Decisions regarding the use of WWTR as a fuel is undertaken at the mill level, depending on the energy and fuel needs of the boilers, the availability of fuels, and the quality of the WWTR generated at the particular mill. Some Maine mills burn all or more than 80 percent of the WWTR that is generated. Some mills have determined that the capital needed to support use of WWTR as fuel is more than the cost of using alternative fuels, and therefore have chosen not to burn the WWTR.

However, the bottom line is that those that burn WWTR for its energy value do so because the material is valuable to that mill.

All mill WWTR should not be classified as waste just because a portion of the fuel happens to be managed for agricultural purposes or landfilled. At Maine facilities, the WWTR is handled as a

valuable fuel up until the point there is a decision to discard it. WWTR at Maine facilities where it is combusted is managed to consistently generate a fuel with valuable heat content. It is segregated, handled, and stored to prevent contamination. At one mill, it is run through a dryer to increase its heat content.

3. What is the amount of WWTR burned as fuel?

In 2011, members of MPPA burned over 75,000 dry tons of WWTR. As examples, Lincoln combusts 100% of its WWTR, Verso mills combusts >80%, while Sappi mills combust > 60%.

4. Clarify what factors determine when WWTR is burned as fuel as opposed to being land applied or disposed.

As described above, a variety of factors go into determinations when a mill will burn WWTR rather than managing it in some other fashion. First and foremost, mills try to reuse as much from the mill as possible - back in the process, to other products, to other uses (such as for fuel), and only at last resort to disposal. The decisions are based on the type of boiler at the particular mill, the type of WWTR generated, the cost of other fuels (both traditional and alternative) in the area of the mill, and the operating conditions of the boiler. Some boilers are not designed to burn WWTR - just as some mills cannot burn coal or natural gas -- so the mill uses other fuels.

There is no one scenario for all Maine mills. However, WWTR that is burned for energy is used because it is a good fuel. The fact that not all WWTR is burned does not negate the value of the material to those mills that have chosen to use it as a fuel.

5. More data on contaminant levels - particularly chlorine and metals. A number of Maine's Mills have submitted extensive data to EPA regarding the chlorine and metal levels in their WWTP residuals in response to EPA information requests.

6. What steps has the industry taken to ensure the quality of pulp and paper mill WWTR when used as a fuel is consistent with that of fuel product? Every pulp and paper mill that generates WWTR does so as part of their compliance with Clean Water Act requirements. The strategies that each mill uses to meet those requirements differ depending upon the type of product, the location of the mill, and the specific standards established by EPA and the respective states. However, in every instance, mills clean wastewaters prior to discharge, thus creating primary and a variety of secondary WWTR, all which capture fibers. Furthermore, the question of whether the quality of the WWTR is appropriate for a particular mill is based on how it is dewatered, handled, stored, and conveyed, as well as boiler design. As such, there are some boilers designed to burn it; others cannot. Maine boilers that burn WWTR are designed to burn WWTR as a fuel.

7. What are the standard practices used to ensure WWTR has meaningful heating value? The overwhelming majority of pulp and paper mills remove water from WWTR prior to managing it in any way. Belt and screw presses are most commonly used in the industry. (e.g., one Verso mill uses screw presses for primary WWTR and a belt press for secondary WWTR, one Verso mill uses a belt press for combined primary and secondary WWTR and Verso uses a rotary dryer using recycled boiler exhaust). In all instances, the goal is to raise the solids content- and thus Btu value.

8. When shipped, how are WWTR managed?

None of the MPPA Mills send their WWTR off-site for purposes of burning as is. WWTR is sent off-site when it is being used by other entities to produce another product used for other purposes (land application, use as landfill cover), or for final disposal. WWTR is shipped by truck or rail in containers.

Response: This comment pertains to the Identification of Non-Hazardous Materials That Are Solid Waste and it is out of scope for this boiler rulemaking. Provided the commenter has submitted this comment to the Identification of Non-Hazardous Materials That Are Solid Waste rulemaking docket, the response to this comment will be provided there.

Commenter Name: Robert E. Hunzinger

Commenter Affiliation: Gainesville Regional Utilities (GRU), Florida

Document Control Number: EPA-HQ-OAR-2002-0058-3488-A1

Comment Excerpt Number: 6

Comment: *Clarification of Criteria for Biomass or Bio-based Fuels and Non-hazardous Solid Waste:*

The treatment of biomass found in the three final NESHAPS rules created uncertainty whether urban biomass would be treated as a biomass fuel or a solid waste subject to the CISWI rule.

While this clarification is found in the CISWI reconsideration rule, the applicability to the Area Source and Major Source reconsideration rules are understood. GRU supports the clarification and believes that the clarification will remove a barrier to expanding the use of several promising biomass fuel sources.⁴

[Footnote]

(4) FR Vol. 76. No. 247, p. 80474 December 23, 2011 *"Specifically, we are proposing to make the following revisions and additions to the definition: (1) Explicitly acknowledge that the list of biomass materials is not exclusive by adding the phrase, "including, but not limited to '"; (2) revise the category 'forest-derived biomass' to include " agricultural biomass"; (3) add hogged fuel, wood pellets, and untreated wood pallets as examples of forest-derived biomass; (4) add the category of "urban wood" and provide examples, including tree trimmings, stumps, and related forest-derived biomass from urban settings ...)*

Response: This comment pertains to the Identification of Non-Hazardous Materials That Are Solid Waste and it is out of scope for this boiler rulemaking. Provided the commenter has submitted this comment to the Identification of Non-Hazardous Materials That Are Solid Waste rulemaking docket, the response to this comment will be provided there.

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 75

Comment: *EPA bases its rules on incorrect assumptions about contamination levels in waste wood.*

EPA paints a rosy picture of how it is possible to render a "clean" fuel stream from C&D. EPA's March 2011 document "Identification of non-hazardous secondary materials that are solid waste" states that when C&D is sorted, painted wood is removed. This is not the case. Painted and contaminated wood is routinely burned.

For instance, the picture below is from the Palmer Renewable Energy (MA) facility's application to the Massachusetts Department of Environmental Protection.¹ The facility actively lobbied against any requirement to sort material to remove painted wood, stating "a specific sorting step for painted wood would result in losses of wood with no lead, losing the opportunity for safe beneficial use of this material".² When we interviewed the plant manager at New England Recycling, the main facility where Palmer would get its wood, he informed us that the "positive pick" process did not remove painted wood from the line. The majority of the wood they sort there is sent to Maine for burning. The picture below clearly shows painted wood in the debris pile from a Maine facility.

The wood in the picture above is described as "clean". The description of the picture is as follows: *"The second facility is Commercial Paving & Recycling Company (CPRC), which operates "wood recycling" operations at the City of Portland Riverside Facility and at CPRC's Scarborough Facility. At these sites, C&D wood is primarily received in a pre-sorted condition. CPRC only accepts pre-sorted, "clean" C&D wood and prohibits plastics, treated woods, non-combustibles, fines (dirt, wallboard, sawdust, roofing materials), asbestos, and metals from the wood storage piles (see Figure 2-7)."*

The "Evergreen Community Power" facility in Reading PA is a synthetic minor source for BACT (we could not ascertain its status with regard to HAPs). A Department of Energy report on the facility³ states that its fuel consists of *"forest industry waste, shredded construction wood waste, and demolition debris. The 'mulch' is mostly wood product, but there are significant amounts of paper, plastic and foreign debris."* The typical fuel composition is shown below.

Comparison with traditional fuels for C&D should be restricted to virgin biomass

EPA states that in determining whether a NHSM meets the legitimacy criteria, its contamination level must be compared to that of a traditional fuel. EPA explicitly states that a facility can compare the contamination level of construction and demolition debris and other wood waste to contamination levels in coal, even if the facility is not permitted to burn coal.

Page 80471:

2. Contaminant Legitimacy Criterion for NHSM Used as Fuels The 2011 NHSM final rule codified three self-implementing legitimacy criteria that NHSM must meet in order to be considered a non-waste fuel when burned in a combustion unit (40 CFR 241.3(d)(1)(i)-(iii)). One of these criteria focused on comparing levels of contaminants contained in the NHSM to levels of those constituents found in traditional fuels. Specifically, the contaminant legitimacy criterion for fuels was finalized as follows: "The non-hazardous secondary material must contain contaminants at levels comparable in concentration to or lower than those in traditional fuels which the combustion unit is designed to burn. Such comparison is to be based on a direct comparison of the contaminant levels in the non-hazardous secondary material to the traditional

fuel itself.” 40 CFR 241.3(d)(1)(iii). The existing language provides flexibility for persons to make comparisons on a contaminant- by-contaminant basis or on a group of contaminants-by-group of contaminants basis in determining what constituents to compare. The phrase “traditional fuels which the combustion unit is designed to burn” also provides the flexibility to choose among multiple fuel options.

This old language did not catch our attention in the previous version of the rule, because it never occurred to us, when talking about C&D, that the "traditional fuel" used for comparison could be anything other than biomass.

Industry groups have expressed concern that the regulatory language does not clearly reflect the EPA’s intent. 9 The EPA agrees that the regulatory language can be revised to better reflect the EPA’s intent in implementing the contaminant legitimacy criterion. Therefore, the Agency is proposing to revise this criterion to read, “The non-hazardous secondary material must contain contaminants or groups of contaminants at levels comparable in concentration to or lower than those in traditional fuel(s) which the combustion unit is designed to burn. In determining which traditional fuel(s) a unit is designed to burn, persons can choose a traditional fuel that can be or is burned in the particular type of boiler, whether or not the combustion unit is permitted to burn that traditional fuel. In comparing contaminants between traditional fuel(s) and a non-hazardous secondary material, persons can use ranges of traditional fuel contaminant levels compiled from national surveys, as well as contaminant level data from the specific traditional fuel being replaced. Such comparisons are to be based on a direct comparison of the contaminant levels in both the non-hazardous secondary material and traditional fuel(s) prior to combustion.” We are taking comment on how this revised contaminant legitimacy criterion would apply to specific fuels.

This is a disaster for new biomass electric plants that are area sources and also overwhelmingly synthetic minor sources for BACT. Under this rule, they would be permitted to wood with contamination levels far above clean biomass, particularly since EPA specifies it is acceptable to use "**ranges** of traditional fuel contaminant levels" for purposes of comparison (not averages or medians). This opens the door to comparing biomass/C&D contaminant levels with the *highest* contaminant levels found in coal. In the face of such a collapse of protection at the federal level, states wishing to protect themselves against C&D burning will be forced to enact new regulations, such as Massachusetts is already doing, in response to the Palmer Renewable Energy proposal to burn C&D which was shown to be so fatally flawed.

This should not be permitted. Clean untreated wood is the obvious "traditional" fuel to which C&D should be compared. C&D wood should not contain contaminants at levels higher than found on average in virgin biomass. This is particularly important for pellet manufacture, since pellets are burned not only in commercial and institutional boilers, such as those found in schools, but also in domestic pellet burners.

EPA must require testing of contaminant levels in fuels

On page 80477, EPA states the following:

Two other issues have arisen during implementation of the 2011 NHSM final rule that, while not leading to specific regulatory changes in today’s proposal, still merit discussion. The first issue

is that contaminant legitimacy criterion determinations do not require testing contaminant levels, in either the NHSM or an appropriate traditional fuel. Persons can use expert or process knowledge to justify decisions to rule out certain constituents.

EPA must require testing for contamination. C&D as a waste fuel is extremely variable. "Slugs" of contaminated wood move through sorting facilities at various times. Particularly given the large amount of material that is going to be generated as abandoned and foreclosed housing is torn down, the potential for liberating vast amounts of lead and other urban toxics, to say nothing of arsenic and chromium from pressure-treated wood, has never been higher. Facilities burning this contaminated material tend to be located in urban areas that already have high levels of air toxics. The Evergreen facility in Reading PA is a good example – it was built (with \$39 million in Stimulus funds) in a county (Berks) that is not only out of attainment with the ozone NAAQS, but also with the lead NAAQS (hard to do, considering it is an order of magnitude lower than it used to be). The region where the plant was built is also an environmental justice area. The facility is burning whatever comes through its door, with waste imported from all over the region, including New Jersey.

The potential for C&D fuel to emit toxics used to be taken seriously by EPA; for instance, in 2010 an ethanol company in Minnesota was fined \$120,000 for burning wood contaminated with lead-based paint and arsenic preservatives in its biomass gasification unit.⁴ With the proposed rule, EPA is removing any hope of regulating contaminants from the biomass power industry. Fuel won't be tested, and emissions won't be regulated, especially given the number of large biomass facilities that claim to be "area" sources.

Definition of "clean" cellulosic biomass has become too expansive

EPA is proposing to modify the definition of "clean" cellulosic biomass. Page 80470:

Clean Cellulosic Biomass The EPA is proposing to revise the definition of "clean cellulosic biomass" to list additional examples of biomass materials that are appropriately included within this definition....

.... Thus, the EPA is proposing to revise the definition of "clean cellulosic biomass" as follows: "Clean cellulosic biomass means those residuals that are akin to traditional cellulosic biomass, including, but not limited to: agricultural and forest-derived biomass (e.g., green wood, forest thinnings, clean and unadulterated bark, sawdust, trim, tree harvesting residuals from logging and sawmill materials, hogged fuel, wood pellets, untreated wood pallets); urban wood (e.g., tree trimmings, stumps, and related forest-derived biomass from urban settings); corn stover and other biomass crops used specifically for the production of cellulosic biofuels (e.g., energy cane, other fast growing grasses, byproducts of ethanol natural fermentation processes); bagasse and other crop residues (e.g., peanut shells, vines, orchard trees, hulls, seeds, spent grains, cotton byproducts, corn and peanut production residues, rice milling and grain elevator operation residues); wood collected from forest fire clearance activities, trees and clean wood found in disaster debris, clean biomass from land clearing operations, and clean construction and demolition wood. These fuels are not secondary materials or solid wastes unless discarded. Clean biomass is biomass that does not contain contaminants at concentrations not normally associated with virgin biomass materials..

Comments on bolded terms:

1. **Hogged fuel.** "Hogging" refers to the process of shredding material. Just because material has been shredded does not make it clean. This description of a process does not belong in this list, which otherwise consists of material fuel sources.
2. **Wood pellets.** Like hogging, pelletizing can be done to almost any material. Wood pellets can be made from any kind of wood. The definition should specify "wood pellets made from virgin biomass materials".
3. **Byproducts of ethanol natural fermentation processes.** This is a discarded waste product and does not deserve the appellation "clean". What is the standard of "virgin biomass" to which is being compared?
4. **Clean wood found in disaster debris.** This again refers indirectly to a process (the process by which standing wood is knocked down in a disaster such as a tornado). This adds nothing to the list that is not already there (i.e., all the "clean" kinds of materials that could be found in disaster debris are already listed).
5. **Clean construction and demolition wood.** This should not be in here, because operationally, this material is discarded by definition. Further, the majority of this material can in no way be considered "clean".

Asbestos should be included as a regulated contaminant

EPA states on page 80475:

Also, we are proposing to exclude from the definition of contaminants those pollutants in the CAA sections 112(b) and 129(a)(4) lists that we do not expect to find in any NHSM.... Fine mineral fibers are excluded because they are releases from the manufacturing and processing (not combustion) of non-combustible rock, glass, or slag into mineral fibers.

Asbestos is commonly found in construction and demolition debris. Asbestos particles in smoke are deadly. Sorting procedures at C&D sorting facilities commonly attempt to remove material that looks like it contains asbestos, but by nature this material can end up in the "fines". The description⁵ of the sorting procedure at a C&D sorting facility in Massachusetts demonstrates why asbestos contamination (and contamination by lead, mercury, and other toxics) is common:*NER accepts mixed C&D waste and separates out ferrous and non-ferrous metals, aggregate (asphalt, brick, concrete (ABC)), OCC (cardboard), plastics (Nos. 1 and 2), gypsum, wood and fines. The mixed C&D is dumped onto the tipping floor where it is inspected for presence of unacceptable materials (hazardous materials, municipal solid waste, and suspect asbestos containing materials). A grapple sorts out large bulky items (large aggregate, bulky insulation or plastics, and large gypsum/wallboard), roughly crushes remaining items and feeds a conveyor to a trommel screen where approx. 1/2 inch fines are removed. The remaining materials move via conveyor onto the sorting line, where some 20 pickers manually remove ABC OCC, metals, and wood. The wood is thus picked off the line by a positive sort.*

Excluding mineral fibers from regulation explicitly ignores the possibility of such contamination in C&D. Asbestos should be a regulated contaminant. [Footnote 1: Palmer Renewable Energy

Project: Major comprehensive air plan approval application, revised June 29,2009. Submitted to MassDEP, Springfield, MA.]

[Footnote 2: Palmer Renewable Energy Project. Beneficial use determination application. Revised June, 2009. Submitted to MassDEP, Springfield, MA.]

[Footnote 3: Department of Energy, Mid-Atlantic Clean Energy Application Center. Evergreen Community Power Plant Case Study. November 16, 2011.]

[Footnote 4: Minnesota Pollution Control Agency. Chippewa Valley Ethanol to pay \$120,000 environmental penalty. April 30, 2010.]

Response: This comment pertains to the Identification of Non-Hazardous Materials That Are Solid Waste and it is out of scope for this boiler rulemaking. Provided the commenter has submitted this comment to the Identification of Non-Hazardous Materials That Are Solid Waste rulemaking docket, the response to this comment will be provided there.

Commenter Name: Shannon S. Broome

Commenter Affiliation: Auto Industry Forum (AIF)

Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1

Comment Excerpt Number: 54

Comment: AIF Supports the Result That Thermal Sand Recycling Not Be Subject to the CISWI Rule and Urges a Similar Result for Recovered Paint Solids as well as Other Appropriate Revisions to the Final Rule.

A. Classification of Thermal Sand Recycling: EPA Should Finalize the Proposed Definition for “Foundry Sand Thermal Reclamation Unit.”

In the preamble to the final NHSM Rule, EPA asserted, for the first time, that it considered foundry sand recycled on-site using a thermal sand reclamation (“TSR”) unit and reused in the same process loop a “solid waste,” thereby making TSR units subject to CAA Section 129’s emission standards. *See CISWI and NHSM Rules*, 76 Fed. Reg. at 15,519. This statement was the first instance in a publicly available document where EPA suggested that TSR units could become subject to the CISWI Rule as “solid waste.” In its petition for reconsideration and subsequent comments, AIF commented that EPA’s statement was arbitrary and contradictory to the CAA, and urged EPA to reconsider and revise it. AIF explained that, under EPA’s line of reasoning, a host of processes not previously contemplated by EPA could become regulated under the CISWI Rule. EPA’s statement, likewise, runs contrary not only to the purposes of the CAA as set forth in Section 101(c),³⁶ AIF explained, but also to EPA’s policy to promote reducing, reusing and recycling, *see* 74 Fed. Reg. 41, 46 (Jan. 2, 2009). AIF articulated that EPA’s line of reasoning would promote increased sand mining, the purchase of virgin sands for the casting industry, and require the disposal, in landfills, of huge volumes of foundry sand, rather than its recycling and reuse. Accordingly, AIF requested EPA to reconsider its determination and clarify that (1) foundry sand being recycled is not a “solid waste” and (2) TSR units are not solid waste incineration units subject to the requirements in the CISWI Rule (either 2000 version or 2011 version).

In the proposal, EPA concludes that TSR units are parts reclamation units as defined in the 2000 CISWI Rule (“unit[s] that burn coatings off parts (e.g., tools, equipment) so that parts can be reconditioned and reused”) because TSR units are “parts reclamation units” that are on foundry sand, which allows re-use of the sand. *CISWI and NHSM Rules Reconsideration Proposal*, 76 Fed. Reg. at 80,463. EPA solicits comment on the proposed definition of TSR units, *see id.*, and elects not to propose standards for TSR units on the basis that it does not currently have emissions data for TSR units and regulation of such units is not required to comply with its CAA § 112(c)(6) obligation. *See id.*

EPA proposes to define “foundry sand thermal reclamation unit” as:

a type of part reclamation unit that removes coatings that are on foundry sand, [and] not an incinerator, waste-burning kiln, an energy recovery unit or a small, remote incinerator under this subpart.

Id. at 80,502. EPA then proposes to define a “burn-off oven” as:

any rack reclamation unit, part reclamation unit, or drum reclamation unit. A burn-off oven is not an incinerator, waste-burning kiln, an energy recovery unit or a small, remote incinerator under this subpart.

Id. Based on these definitions, then, TSR units would not be regulated under the CISWI Rule because EPA has determined that it will not regulate burn-off ovens under the regulation.³⁷ *See, e.g., id.* at 80,460. While AIF does not believe that TSR units qualify as CISWI units more generally, it also agrees that TSR units should not be subject to CISWI requirements because they significantly reduce landfill through reuse, such units are numerous and there are a lack of emissions data available for them. Just like burn-off ovens, these are activities that EPA should create policies to encourage, rather than discourage by regulating them under CISWI.³⁸

Accordingly, consistent with its prior submittals on this issue, AIF supports both EPA’s clarification that TSR units are not incinerators and its proposed definition of “foundry sand thermal reclamation unit” in that it results in TSR units not being subjected to the CISWI rule requirements.³⁹ [Footnote 36: “A primary goal of this chapter is to encourage or otherwise promote reasonable Federal, State, and local government actions, consistent with the provisions of this chapter, for pollution prevention.” CAA § 101(c); 42 U.S.C. § 7401(c).]

[Footnote 37: In fact, TSR units have never been contemplated as falling within the CISWI program since its inception. The purpose of a TSR unit is neither to “combust” the sand, nor to reduce the volume of the sand, nor to generate heat for reuse. The purpose is simply to reuse the sand in the making of new sand cores and molds. EPA never intended to include these types of processes in the CISWI Rule.]

[Footnote 38: EPA also noted it was not required to include such units to comply with their Section 112(c)(6) obligations to identify categories of sources of pollutants to assure that sources accounting for not less than 90 percent of the aggregate emissions of each such pollutant are subject to Section 112 standards. *See CISWI Rule*, 76 Fed. Reg. at 15,708, 15,734. To the extent Section 112(c)(6) is relevant, the same rationale applies to TSR units.]

[Footnote 39: For the reasons explained in its petitions for rulemaking and reconsideration, AIF does not agree that TSR units are incinerators even should they not fall within the definition of parts reclamation units and our support for the proposed definition should not be interpreted as conceding this point. However, since its members would not be affected by the rule given the proposed definition, AIF supports the exclusion (albeit on different grounds).

Response: This comment pertains to the Identification of Non-Hazardous Materials That Are Solid Waste and it is out of scope for this boiler rulemaking. Provided the commenter has submitted this comment to the Identification of Non-Hazardous Materials That Are Solid Waste rulemaking docket, the response to this comment will be provided there.

Commenter Name: Shannon S. Broome

Commenter Affiliation: Auto Industry Forum (AIF)

Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1

Comment Excerpt Number: 55

Comment: Classification of Recovered Paint Solids: EPA Should Adopt an Exclusion from the CISWI Rule for Recovered Paint Solids Collected from Automobile Assembly Plants that are Combusted for Energy Recovery.

In its petition for reconsideration and subsequent comments, AIF called upon EPA to clarify that the regulations consider recovered paint solids collected from automobile assembly plant painting operations a non-hazardous secondary material, *i.e.*, NHSM, not a “solid waste” subject to the CISWI Rule. AIF conveyed to EPA that such recovered paint solids are not hazardous but, instead, serve as a valuable commodity and are managed as similar valuable commodities such as scrap tires combusted as alternative fuels. Rather than promote energy recovery from these materials, AIF commented, classifying recovered paint solids in the CISWI Rule not only would increase the amount of paint solids diverted to landfill, including by facilities owned and/or operated by AIF members, but also increase the use of fossil fuels due to the fuels that facilities would need to burn instead of recovered paint solids. Accordingly, AIF advocated for EPA to adopt an exclusion from the CISWI Rule for recovered paint solids collected from automobile assembly plants.

The proposal fails to respond to or even discuss AIF’s petitions and comments. Accordingly, here, AIF reiterates both its concerns about the classification of recovered paint solids and its recommended revisions. In the final reconsideration rule, EPA should clarify that recovered paint solids collected from automobile assembly plant operations, categorically, are not a “solid waste” subject to the CISWI Rule but, rather, a non-hazardous secondary material under the NHSM Rule. Several rational bases support such action. First, recovered paint solids collected from automobile assembly plant operations are not hazardous materials. On the basis of test burns, for example, state regulators have already determined that the combustion of paint solids is acceptable. Second, they serve a legitimate energy recovery function because they are regarded as a valuable commodity in that they provide a beneficial use as a fuel, with similar BTU value to coal. Facilities contract with the automotive companies, AIF’s members included, to accept recovered paint solids for use as fuel, like coal, in coal-fired boilers. Recovered paint solids are managed similar to coal and mixed prior to combustion. They have attributes comparable to scrap tires, which EPA proposes to classify as non-wastes, in large part, because contractual

arrangements exist whereby, in lieu of automotive companies discarding them, combustors receive scrap tires for use as fuel. *See, e.g., id.* at 80,476. Since the purpose of burning recovered paint solids “is not to destroy or discard them, as they are clearly considered and managed as a valuable commodity to the manufacturing process,” EPA should classify them as non-waste, just as EPA proposes to classify resinated wood. *Id.* at 80,483.

EPA should promote the energy recovery inherent in the use as fuel of recovered paint solids collected from automobile assembly plants. Classifying these materials in the CISWI Rule would only increase the amount of materials diverted to landfill, including by facilities owned and/or operated by AIF members. Moreover, it would increase the use of fossil fuels because facilities would need to burn fossil fuels instead of recovered paint solids. In the final reconsideration rule, therefore, EPA should classify as non-hazardous secondary material paint solids collected from automobile assembly plants that are burned for energy recovery. As a corollary, EPA should exclude recovered paint solids from the CISWI Rule.

Response: This comment pertains to the Identification of Non-Hazardous Materials That Are Solid Waste and it is out of scope for this boiler rulemaking. Provided the commenter has submitted this comment to the Identification of Non-Hazardous Materials That Are Solid Waste rulemaking docket, the response to this comment will be provided there.

Commenter Name: Alicia Meads

Commenter Affiliation: National Association of Manufacturers (NAM)

Document Control Number: EPA-HQ-OAR-2002-0058-3515-A1

Comment Excerpt Number: 3

Comment: Fail to list important biomass materials as fuels. Important biomass materials such as paper recycling residuals, pulping sludge, wood construction debris and railway ties are still not listed as fuels, which creates great uncertainty for the businesses that rely on them. The failure to list such materials as fuels means that the boilers burning such fuels could be regulated under the onerous and stigmatizing incinerator standards. Alternatively, those materials could end up being sent to landfills, rather than being used to produce energy—a bad result for jobs and the environment.

Response: This comment pertains to the Identification of Non-Hazardous Materials That Are Solid Waste and it is out of scope for this boiler rulemaking. Provided the commenter has submitted this comment to the Identification of Non-Hazardous Materials That Are Solid Waste rulemaking docket, the response to this comment will be provided there.

Commenter Name: Roger Martella

Commenter Affiliation: National Alliance of Forest Owners (NAFO)

Document Control Number: EPA-HQ-OAR-2002-0058-3519-A1

Comment Excerpt Number: 4

Comment: The NHSM rule is of critical importance to NAFO’s members because it determines whether the co-products associated with biomass production processes are considered fuels subject to the Major Source rule or solid waste subject to the more stringent CISWI rule when combusted for energy. The combustion of biomass residuals for energy is an important

component of the production processes for many of NAFO members' customers. Other customers rely on these materials as valuable co-products which can be sold for energy production by third parties. Yet experience has shown that classifying these materials as "solid waste" ensures that they will not be combusted for energy due to the high costs of compliance with CISWI standards. Rather than attempting to meet the more stringent limits, facilities will simply switch to other fuels that are subject to the less stringent Major Source rule standards.

The NHSM rule promulgated by EPA in March 2011 suffers from a number of flaws that will harm NAFO members and prevent the use of many clean, renewable secondary materials for biomass energy production. First, the definition of clean cellulosic biomass lacked sufficient clarity, creating uncertainty whether certain types of biomass were considered clean cellulosic biomass and could be combusted for energy without triggering CISWI requirements. Second, the rule improperly classified many traditional biomass fuels as solid waste despite their long history of use as valuable fuel products. Third, the limited access to complicated petitioning processes failed to provide adequate redress for regulated entities (and their suppliers) when the default rules classified their biomass fuel supplies as solid waste.

The proposed rule includes a number of revisions that will have a positive impact on NAFO's members and appropriately encourage the use of biomass secondary materials as valid traditional fuels. As described below, NAFO generally supports EPA's proposed changes, but believes that additional changes are needed to accurately reflect the historic role of biomass secondary materials as traditional fuels.

A. EPA Must Not Exceed Its RCRA Authority by Seeking to Regulate Biomass Energy Feedstocks That Have Not Been Discarded

EPA's authority over secondary materials is limited to material that has been discarded. Under RCRA, only material that has been "discarded" meets the definition of "solid waste." *See Ass'n of Battery Recyclers v. EPA*, 208 F.3d 1047, 1051 (D.C. Cir. 2000) ("Congress unambiguously expressed its intent that 'solid waste' (and therefore EPA's regulatory authority) be limited to materials that are 'discarded' by virtue of being disposed of, abandoned, or thrown away."). The D.C. Circuit has also established the transfer of a co-product from a generator to a third party does not create a presumption that the material has been discarded because firms may prefer to transfer biomass co-products to third parties who can use them more efficiently. *Safe Food and Fertilizer v. EPA*, 350 F.3d 1263, 1268 (D.C. Cir. 2003) ("As firms have ample reasons to avoid complete vertical integration, . . . firm to firm transfers are hardly a good indicia of a 'discard' as the term is ordinarily understood." (citation omitted)). As such, if a material is a valuable product or industrial input, and handled as such, EPA cannot regulate it under RCRA.)

As described above, biomass provides a clean, renewable, alternative to fossil fuels and represents an important part of the Administration's clean energy policy. In order to support and further that policy, EPA must adopt regulations that support existing biomass energy facilities and encourage the development of new biomass energy facilities, whether they rely on traditional biomass fuels or, through ingenuity, develop new energy opportunities for biomass co-products. Any presumption that biomass co-products are discarded waste products is inconsistent with this objective and, as described below, we urge EPA to avoid such presumptions in its regulations. While a policy of encouraging biomass energy would be most consistent with the Administration's goals, EPA must not take positions that are in conflict with that goal. At a

minimum, EPA must adopt a neutral policy that does not presume biomass materials are discarded solid waste.

Accordingly, we urge EPA to interpret its RCRA authority narrowly to ensure that the materials it seeks to regulate have actually been discarded. Any material that is treated by generators or their customers as a valuable fuel feedstock and is actually combusted for energy production has not been discarded and thus is outside of EPA's authority under the NHSM rule. It is irrelevant whether the material is a traditional or newly developed fuel or whether the fuel is combusted by the generator or by a third party. In any case, biomass materials with value as energy feedstocks are not discarded and should not be subject to EPA's authority under RCRA or the more stringent CISWI emissions limitations.

B. Definition of "Clean Cellulosic Biomass," 40 C.F.R. § 241.2

NAFO believes that all trees and all other materials taken from the forest are "clean" cellulosic biomass and supports EPA's conclusion that clean cellulosic biomass materials are traditional fuels and thus are not solid waste when burned for energy. NAFO supports EPA's decision to clarify the definition of clean cellulosic biomass by including more comprehensive examples of secondary materials that qualify as clean cellulosic biomass. However, we believe that additional steps can be taken to provide greater clarity to the rule and greater assurance to regulated entities that additional forest products qualify as clean cellulosic biomass and will not be considered solid waste.

NAFO agrees with EPA's conclusion that the list of materials included in the clean cellulosic biomass definition should not be considered exhaustive and supports EPA's addition of the phrase "including, but not limited to" in the definition. 76 Fed. Reg. at 80,470. This change will provide regulated entities with the assurance that unlisted materials will not be categorically considered to be solid waste and provide them with the flexibility to alter fuel mixes and incorporate traditional fuels that are not explicitly listed in the definition of clean cellulosic biomass without fear of becoming subject to the more stringent CISWI emissions standards.

In NAFO's comments on the June 4, 2010 Proposed NHSM rule, we suggested adding clarity to the forest derived biomass portion of cellulosic biomass definition.²¹ We appreciate EPA's explanation on page 173 in its "Responses to Comments Document for the Identification of Nonhazardous Secondary Materials That Are Solid Waste Rulemaking (February 2011)," posted at EPA-HQ-RCRA-2008-0329 on March 21, 2011: "Under the final rule, forest-derived biomass, including green wood, forest thinnings, clean and unadulterated bark and tree harvestings residuals, is considered an alternative traditional fuel. The categories would encompass dead trees and wood residues." NAFO also supports EPA's decision to include "hogged fuel, wood pellets, untreated wood pallets[, and] urban wood (e.g. tree trimmings, stumps, and related forest-derived biomass from urban settings)" and "byproducts of ethanol natural fermentation processes" within the definition clean cellulosic biomass. This expanded definition, along with EPA's response to NAFO's comments, will provide assurance to the entities that produce and combust these traditional biomass energy fuels and appropriately encourages their use clean, renewable fuels.

However, we urge EPA to provide greater clarity by removing from the final rule the caveat that "Clean biomass is biomass that does not contain contaminants at concentrations not normally

associated with virgin biomass materials." 76 Fed. Reg. 80, 529. Despite EPA's efforts to provide an expansive definition of clean cellulosic biomass that accurately reflects the wide range of biomass feedstocks that have traditionally been used as fuels – and thus have not been discarded – this final requirement suggests that these traditional fuels must still satisfy the legitimacy criteria discussed in section II.E in order to avoid being classified as solid waste. It also perpetuates EPA's erroneous interpretation of its authority under RCRA, which is expressly limited to discarded material and does not encompass traditional fuels. This definition of clean cellulosic biomass will be of little value to regulated entities if they are required to complete the NHSM regulatory process and demonstrate compliance with the legitimacy criteria even if the biomass fuels they combust are explicitly included in the definition of clean cellulosic biomass. Thus in addition to removing this confusing sentence, we urge EPA in the preamble to the final rule to clarify that the feedstocks explicitly listed in the definition of clean cellulosic biomass are traditional fuels that are not subject to EPA's RCRA authority over discarded materials, whether combusted by generators or by third parties.

C. Administrative Petition Process for Non-waste Determinations for Non-Generators, 40 C.F.R. § 241.3(c)

Despite the additional clarity provided by the revised definition of clean cellulosic biomass, many biomass materials used as fuels are not listed and must instead be considered on a case-by-case basis. For borderline cases, the administrative petition process – which currently presumes that all biomass co-products combusted by entities other than generators are solid waste – offers a means to obtain assurance that EPA will consider the material to be a fuel and not solid waste. NAFO supports EPA's efforts to streamline and add flexibility to the petition process, but believes that additional steps can be made to make the process consistent with the law and more workable in practice.

The proposed rule clarifies a number of features that streamline and add flexibility to the administrative petition process. NAFO agrees with EPA that any interested person – including forest owners – should be able to initiate the petition process. It also agrees that petitions should be allowed for entire classes of combustors rather than requiring a case-by-case analysis. These clarifications will encourage all members in the biomass supply chain to promote their products and co-products as clean, renewable fuels and promote the development of new markets for biomass materials. However, NAFO believes that these benefits could be achieved more efficiently by allowing for nation-wide petitions for classes of combustion units rather than requiring separate petitions for each EPA region.

NAFO also believes that the administrative petition process could be further streamlined by not seeking public comment on every individual petition. By filing an administrative petition, a petitioner is not seeking to change EPA's regulatory program or create new legal rights or obligations. Instead, the administrative petition process provides an opportunity for a petitioner to obtain in advance agency concurrence, based on sound science, with respect to the classification of a particular feedstock under existing regulations. In this respect, the administrative petition process differs from the categorical non-waste determination discussed below, where EPA makes changes the regulatory status of certain secondary materials that are reflected in the Code of Federal Regulations. Because the public – through this rulemaking process – has an opportunity to provide input on EPA's regulations, there is no need to provide a

second opportunity for public comment when those regulations are applied by EPA in specific contexts through the administrative petition process.

While EPA's proposed changes are beneficial, NAFO believes that additional changes could further streamline and provide greater flexibility to the administrative petition process. First EPA should adopt a more flexible approach to evaluating petitions, recognizing – as it does in the categorical non-waste determination process – that fuels should not be considered solid waste, even if they do not meet each of the legitimacy criteria. Second, EPA should not distinguish between secondary materials combusted by generators and third parties. The current default rule presuming that secondary materials combusted by third parties are solid waste ignores the fact that third parties have traditionally combusted biomass material for energy and discourages the development of new markets for clean, renewable biomass co-products and is not consistent with Congressional intent in RCRA that EPA only has authority over material that has been discarded. Instead, EPA should permit non-generators to make the same self-determination as generators that their secondary material fuels are not solid waste. Under this approach, the administrative process would still play a valuable role in providing assurance to all regulated entities in borderline cases.

D. Categorical Non-Waste Determinations for Specific NHSM, proposed 40 C.F.R. § 241.4

NAFO supports EPA's adoption of its recommendation to categorically classify resinated wood as non-waste.²² As described more fully in our previous comments, resinated wood residuals have been used as a traditional fuel source since the 1950s²³ and we applaud EPA's recognition of this traditional fuel source. NAFO also urges EPA make full use of the proposed categorical non-waste determination process and aggressively consider categorical determinations for other traditional fuels.

As explained in our previous comments, there are a number of traditional biomass fuels that may not qualify as clean cellulosic biomass under the strict criteria included in the current. Nevertheless, these secondary materials have a long history of use as energy feedstocks and should not be classified as solid waste. Among these traditional fuels are construction and demolition debris; pulp and paper wastewater residues, which consist largely

of biomass (wood fiber); paper recycling residuals; and certain treated woods, such as creosote-treated railroad ties. We concur with the analyses submitted by the American Forest & Paper Association in support of a categorical non-waste determination for pulp and paper wastewater residues (pulp and paper sludge) and for construction debris. NAFO supports EPA's proposed Categorical Non-Waste Determination Process as a means to exclude these traditional fuel products from the definition of solid waste and to provide regulated entities with the necessary assurances that their combustion will not trigger more stringent CISWI emissions limits.

To determine whether a non-hazardous secondary material should be granted a categorical non-waste determination, EPA must focus primarily on whether the secondary material has been discarded or whether it is treated as a co-product with value as an energy feedstock because, as described above, EPA's regulatory authority over secondary material is limited to material that is discarded. *See Ass'n of Battery Recyclers*, 208 F.3d at 1051 While consideration of other factors such as the legitimacy criteria may aid EPA in making that determination, EPA should make clear in the final rule that secondary material will qualify as non-waste if the petitioner can

demonstrate that it has not been discarded, but is used instead as a fuel source by the generator or third parties.

To this end, NAFO supports EPA's proposal to add flexibility to the petition and review process for making categorical determinations. First, NAFO supports EPA's proposal to apply the categorical determinations to all combustors and not merely to generators of secondary materials. This approach appropriately recognizes the many circumstances in which generators have treated their secondary materials as valuable co-products and developed markets for their combustion for energy by third parties. Second, NAFO supports EPA's proposal to allow any person to file a categorical determination petition with EPA. In doing so, EPA appropriately recognizes that other entities besides the generator and combustor have an interest in properly categorizing traditional fuels as non-waste and in developing new opportunities to utilize biomass secondary materials as raw materials in other industrial processes. Third, NAFO supports EPA's decision to balance the legitimacy criteria with other factors. Many traditional fuels have a long history of use for energy combustion, but may not meet each of the legitimacy criteria. By balancing the legitimacy criteria with other factors, EPA can take a more flexible approach that can emphasize historic uses of biomass secondary material and respond to new markets as they develop.

E. Legitimacy Criteria, 40 C.F.R. § 241.3(d)

NAFO also supports EPA's proposals to incorporate additional flexibility to the legitimacy criteria applied to NHSM. As explained in our earlier comments, the legitimacy criteria are unnecessarily stringent and will inappropriately exclude some NHSM that are validly reused as energy feedstocks.²⁵

While the proposed rule makes a several improvements, the legitimacy criteria remain unnecessarily stringent.

First, NAFO agrees with EPA's proposal to provide regulated entities with the flexibility to apply the legitimacy criteria to individual contaminants or entire classes of contaminants as appropriate. This change will provide greater flexibility to accurately compare the environmental and health impacts of NHSM and traditional fuels. Second, NAFO supports EPA's proposal to permit comparisons to any traditional fuel that could be combusted in the unit. Again, this added flexibility offers a better opportunity to compare the environmental and public health impacts of NHSM and the traditional fuel alternatives that could be combusted in their place.

However, NAFO continues to disagree with EPA's decision to place more stringent requirements on legitimacy criteria for NHSM than it does for hazardous materials. First, EPA should recognize that some traditional fuels do not meet each of the legitimacy criteria and permit balancing of the legitimacy criteria – as it proposes to do under the categorical non-waste determination process – instead of requiring strict compliance with each criterion. Second, rather than limiting NHSM to those with "contaminants at levels comparable to or lower than those in traditional fuels," 40 C.F.R. § 241.3(d)(1)(iii), EPA should adopt the standard traditionally applied to hazardous materials where contaminants cannot be present "at levels that are significantly elevated from those found in analogous products." 40 C.F.R. § 260.43(c)(2)(ii). There is simply no justification for applying more stringent standards for secondary materials that are non-hazardous than for those that are hazardous.[Footnote 21: NAFO NHSM RuleComments,at 3-4.]

[Footnote 22: NAFO NHSM RuleComments,at 3-4.]

[Footnote 23: NAFO NHSM RuleComments,at 3-4.] [Footnote 24: NAFO NHSM RuleComments,at 3-4.]

Response: This comment pertains to the Identification of Non-Hazardous Materials That Are Solid Waste and it is out of scope for this boiler rulemaking. Provided the commenter has submitted this comment to the Identification of Non-Hazardous Materials That Are Solid Waste rulemaking docket, the response to this comment will be provided there.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 3

Comment: As anticipated, EPA has addressed several significant elements of the March 2011 Final NHSM rule, which have the effect of reclassifying sources between the incinerator and boiler categories and among subcategories in each rule. Even during the development of and comment period on the Proposed Reconsidered NHSM rule, EPA issued three interpretive letters that directly affected subcategory populations. 76 Fed. Reg. 80473. Among the sources whose classifications were directly affected are CIBO members. And EPA went on to propose other significant changes in the fuel definition that must be accounted for by sources in their compliance plans. Even publishing the Final Reconsidered NHSM rule, however, will not fully determine the status as waste or NHSM of many materials currently being used as fuel, and that rule provides a petition process to make those determinations. Sources that are unsure about the status of their materials will petition EPA for determinations of the status of their materials, and on the basis of those determinations, the sources will then know whether their continued use of those materials will classify the source as an incinerator or boiler. CIBO has urged EPA to establish a timeline for completion of the initial round of waste/fuel determinations, although the Proposed Reconsidered NHSM Rule does not indicate a date-certain by which sources will have final decisions regarding the status of their materials.

Response: This comment pertains to the Identification of Non-Hazardous Materials That Are Solid Waste and it is out of scope for this boiler rulemaking. Provided the commenter has submitted this comment to the Identification of Non-Hazardous Materials That Are Solid Waste rulemaking docket, the response to this comment will be provided there.

Commenter Name: Kristin Palecek

Commenter Affiliation: Flambeau River Papers

Document Control Number: EPA-HQ-OAR-2002-0058-3541-A1

Comment Excerpt Number: 1

Comment: While the EPA has fixed some of the problems with the proposed Boiler Maximum Achievable Control Technology (MACT) rule compared with previous versions of the rule, I still have many concerns. One step in the right direction was the secondary non hazardous materials rule that will decide under which rule a boiler is operated; however, there should be a way to make the majority of these determinations without EPA involvement. Since the Wisconsin

Department of Natural Resources already does an overly thorough job, this is a particularly frustrating issue in Wisconsin. There may be a few cases where a determination from EPA is needed, but this requirement creates an unnecessary burden on the company, the fuel supplier, and the EPA. Companies should be able to make decisions on their own with clear criteria. It should be possible for companies to keep records of how and why they made their determinations. Companies would be required to keep this information available if questions arise in the future. As an example, the small paper mill that I work at will need to have two determinations made. The two fuels are unique, but both are mainly wood. Having some sort of threshold set up that says that if something is 90% of a traditional fuel with the remaining material not falling under the RCRA rules would be one suggested method. Another example that comes to mind is for facilities with anaerobic digesters that are burning the biogas that is generated. Since the majority of the biogas is methane with carbon dioxide making up the majority of the difference, the biogas should be regulated similar to natural gas under the Boiler MACT rule.

Response: This comment pertains to the Identification of Non-Hazardous Materials That Are Solid Waste and it is out of scope for this boiler rulemaking. Provided the commenter has submitted this comment to the Identification of Non-Hazardous Materials That Are Solid Waste rulemaking docket, the response to this comment will be provided there.

Commenter Name: John M. Cullen

Commenter Affiliation: Masco Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3661-A2

Comment Excerpt Number: 1

Comment: Solid Waste Definition

- In its August 2, 2010 comments, Masco addressed the definition of "solid waste" in EPA's parallel rulemaking, "Identification of Non-Hazardous Secondary Materials That Are Solid Waste", proposed rule (75 Fed. Reg. 31844, June 4, 2010). EPA explained the purpose of its parallel ("NHSM") rulemaking as follows:

The meaning of "solid waste" as defined under RCRA is of particular importance since it will determine whether a combustion unit is required to meet emissions standards for solid waste incineration units issued under section 129 of the Clean Air Act (CAA) or emissions standards for commercial, industrial, and institutional boilers issued under CAA section 112.

- Masco biomass-fueled boilers combust wood or resinated wood material generated from the manufacture of cabinetry. Masco commented that such wood fuels, which are either combusted or sold to other manufacturers for use as fuel, are not solid waste and therefore the NHSM rule (and by implication, the Boiler MACT and CISWI2 rules) should be clarified to ensure that combustion of such solid wood fuels would not subject the boiler to regulation as an incinerator under the CISWI or Boiler MACT rules. Masco is pleased to note that EPA essentially agrees, and has clarified in the parallel rulemaking, that such "clean wood" or "resinated wood" solid fuels are generally not solid waste for purposes of the NHSM rule or the Boiler MACT and CISWI rules. See 76 Fed. Reg. 15459.

- Nevertheless, the NHSM rule provides that resinated wood must still satisfy certain "legitimacy criteria" in order to maintain its status as a solid fuel rather than a solid waste. See 76 Fed. Reg. 15459. Masco continues to believe that resinated wood should be treated as any other traditional fuel and therefore be fully and specifically exempt from further regulation, including the "legitimacy criteria" imposed by the NHSM final rule.

Response: This comment pertains to the Identification of Non-Hazardous Materials That Are Solid Waste and it is out of scope for this boiler rulemaking. Provided the commenter has submitted this comment to the Identification of Non-Hazardous Materials That Are Solid Waste rulemaking docket, the response to this comment will be provided there.

Commenter Name: Shawn Good

Commenter Affiliation: Pennsylvania Chamber of Business and Industry

Document Control Number: EPA-HQ-OAR-2002-0058-3671-A2

Comment Excerpt Number: 2

Comment: The Pennsylvania Chamber supports a holistic approach to the fuel versus waste determination that considers historical purposes and uses of the combustion material, rather than narrow application of one or a few legitimacy criteria.

In the proposed revised definition of solid waste materials, EPA has proposed listing certain (biomass) materials that will be simply designated as non-waste in the definition, regardless of their status under the legitimacy criteria. In addition, EPA proposed more flexibility in the application of the legitimacy criteria, insofar as EPA applies the criteria, after the rules are finalized, when making a categorical determination for a particular fuel that would apply to all sources burning that fuel. The Pennsylvania Chamber supports this proposed approach to the fuel vs. waste determination, which will reduce the instances where the rule that applies to an individual boiler hinges on a specific consideration under the legitimacy criteria, (e.g., whether the material is generated on or off site). The Pennsylvania Chamber urges EPA to clarify in the final rules that this holistic approach will also be applied when making unit-specific fuel versus waste determinations. Such an approach will more accurately distinguish between those materials which have been discarded and are truly being burned as waste from materials which have the characteristics of a legitimate fuel, but may not satisfy all of the legitimacy criteria, which of necessity are designed to cover a broad range of circumstances.

Response: This comment pertains to the Identification of Non-Hazardous Materials That Are Solid Waste and it is out of scope for this boiler rulemaking. Provided the commenter has submitted this comment to the Identification of Non-Hazardous Materials That Are Solid Waste rulemaking docket, the response to this comment will be provided there.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 181

Comment: API urges EPA to reaffirm the status quo and promulgate a final NHSM Rule under which EPA presumes that non-hazardous secondary material (NHSM) that is burned for energy recovery or used as an ingredient in a combustion unit is not a waste. Starting from that presumption, EPA can then use the NHSM Rule to identify wastes. However, that is not the framework of the current NHSM Rule. That rule starts from the presumption that all NHSM that are combusted are wastes, and then identifies conditions under which NHSM may be identified as non-waste. The FRRC comments in docket EPA-HQ-RCRA-2008-0329 (incorporated by reference) explain the following main points in detail:

- The NHSM proposal exceeds EPA's authority under RCRA. There are major flaws in the contaminant legitimacy criterion, categorical determinations that a material is a non-waste fuel, and the proposed rulemaking petition process.
- The proposal is arbitrary and capricious under the administrative procedure act because: o EPA has no record to support its determination that most NHSM that are combusted are wastes; and
- EPA has provided no rationale to support its presumption that almost all NHSM combustion constitutes disposal.
- EPA should establish the presumption that most NHSM is not a waste when combusted for energy recovery or for use as an ingredient.
- EPA must correct earlier misstatements regarding the status of certain categories of NHSM and make other clarifications. o EPA's statements on gaseous fuels are inconsistent with its acknowledgement that gas that is not contained in a container is not a waste.
- EPA's statements on thermal treatment are inconsistent with its recognition that destruction of a contaminant is not dispositive evidence of discard and that materials that are being continuously used in an industrial process are not discarded, even when reclaimed.
- EPA treatment of ingredients as waste is illogical and inconsistent with RCRA.
- EPA's statements on off-specification used oil are inconsistent with RCRA.

The FRRC comments on the NHSM proposal explain how EPA's NHSM rule undermines the basis for the Boiler NESHAP and CISWI Rules, and other NESHAP standards. Section 129 of the Clean Air Act provides that a unit that is a commercial and industrial solid waste incinerator is subject to the CISWI Rule, and no other NESHAP standards. 42 U.S.C. 7429(h)(e). If a unit combusts solid waste, it is a CISWI unit. The NHSM Rule is intended to provide the basis for distinguishing between CISWI units and other combustion units by identifying what material is a solid waste when combusted. Unfortunately, the proposed revisions to the NHSM Rule do not add the clarity and certainty needed by both EPA and the regulated community to determine what units are CISWI units and what units are subject to other MACT standards.

Response: This comment pertains to the Identification of Non-Hazardous Materials That Are Solid Waste and it is out of scope for this boiler rulemaking. Provided the commenter has submitted this comment to the Identification of Non-Hazardous Materials That Are Solid Waste rulemaking docket, the response to this comment will be provided there.

Commenter Name: Richard D. Garber
Commenter Affiliation: Boise Inc.
Document Control Number: EPA-HQ-OAR-2002-0058-3686-A2
Comment Excerpt Number: 4

- **Comment:** Our four integrated pulp and paper mills have a total of five solid fuel-fired boilers which would be regulated under the "wet biomass stokers" subcategory. These boilers principally burn clean biomass (bark and wood residues) but also burn other NonHazardous Secondary Materials (NHSM) such as urban wood, wastewater treatment residuals, tire derived fuel, and cross tie derived fuel. Our biomass boilers also burn other incidental NHSM such as used oil and recycled paper residuals for fuel. Thus, there is the potential that our biomass stoker boilers could become Commercial Industrial Solid Waste Incinerators (CISWI) with their historical fuel mix, depending on how EPA decides the "fuel vs. solid waste" issue. Boise has previously provided comments on the proposed NHSM rule (August 2, 2010, submitted to rradocket@epa.gov) and supports the current comments on the NHSM rule re-proposal submitted by AF&PA and NCASI.

Response: This comment pertains to the Identification of Non-Hazardous Materials That Are Solid Waste and it is out of scope for this boiler rulemaking. Provided the commenter has submitted this comment to the Identification of Non-Hazardous Materials That Are Solid Waste rulemaking docket, the response to this comment will be provided there.

1B. Out of Scope: CISWI

Commenter Name: Lorraine Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1
Comment Excerpt Number: 147

Comment: FUEL TO WASTE SWITCHING PROVISIONS

ACC has long advocated the need for combustion units that intermittently burn solid waste to be able to move between §129 and §112 as applicable, and included comments on this issue in our submissions on both the proposed CISWI rule and the 2010 Proposed Boiler Rule . ACC does not support the fuel switching requirements that EPA promulgated in the final CISWI rule and believes EPA exceeded its statutory authority in the approach it took. In this reconsideration, EPA requests comment "on the fuel switching provisions included in the final CISWI rule, particularly on whether the provisions should include further clarification on the timeline and regulatory requirements of a fuel switch. Additionally, we are soliciting comment on an alternative time period for switching frequency (e.g., 12 months)." 76 Fed. Reg. 80458-80460 (Dec. 23, 2011). ACC appreciates the opportunity to submit comments again on this important issue and hope that EPA will seriously consider finalizing the approach advocated below.

Response: This comment pertains to the CISWI rulemaking, and it is out of scope for this boiler rulemaking. Provided the commenter has submitted this comment to the CISWI rulemaking docket, the response to this comment will be provided there.

Commenter Name: Lorraine Gershman
Commenter Affiliation: American Chemistry Council (ACC)
Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1
Comment Excerpt Number: 148

Comment: *EPA Should Abandon its Proposed Fuel-Switching Requirements for Regulating Sources that Intermittently Combust a Solid Waste Because EPA Lacks Authority Under §129 to Regulate these Units as CISWI When They Are Not Burning a Solid Waste.*

Some ACC members operate units that intermittently combust a solid waste generated on-site from manufacturing operations. These units switch between burning a traditional fuel and solid waste fuel as needed. ACC appreciates EPA's attempt to address fuel-switching and acknowledge that it presents some unique regulatory issues as these units move from being regulated under §129 as CISWI to being regulated under §112 as boilers, and vice versa. *See* 76 Fed. Reg. 80458–60. However, ACC believes that the approach EPA has chosen to address such fuel switching is contrary to the plain language of §129 and unlawful.

EPA's proposed approach is that “[u]nits that cease combusting solid waste remain subject to CISWI for at least 6 months after solid waste is added to the combustion chamber. After 6 months, sources must either comply with any applicable section 112 standards or, if they intend to combust solid waste in the unit in the future, opt to remain subject to CISWI.” *Id.* at 80501 (to be codified at 40 C.F.R. §60.2265). The proposed definition of CISWI unit in § 60.2265 reads in relevant part “any distinct operating unit of any commercial or industrial facility that combusts, *or has combusted in the preceding 6 months*, any solid waste.” (Emphasis added).

The requirement that sources remain subject to CISWI for 6 months after their last combustion of solid waste is unlawful. Section 129(g)(1) defines solid waste incineration unit, in relevant part, as “a distinct operating unit of any facility which *combusts* any solid waste material.” (Emphasis added). Congress did not say “which combusts, *or has combusted in the preceding 6 months*, any solid waste,” or more generally, “which *recently combusted* any solid waste material.” Instead, Congress chose the present tense “combust” to express its clear intent to regulate only units currently combusting solid waste. EPA must “give effect to the unambiguously expressed intent of Congress” under step 1 of the *Chevron* test. *See Chevron USA v. NRDC*, 467 U.S. 837, 842-43 (1984). Since Congress was clear in its intent to only regulate solid waste incineration units *currently* combusting waste, EPA's expansion of the definition of CISWI to regulate units that *have* burned waste in the past but have stopped is illegal.

Similar reasoning applies to EPA's proposal in §60.2145(a)(4) that a CISWI unit give EPA 30-days' notice prior to the effective date of a fuel switch from a waste to a non-waste fuel. This prior notice requirement also continues to illegally regulate the unit under § 129 after it has ceased burning waste. For example, a unit that stops combusting waste on January 1st and notifies EPA of its waste-to-fuel switch on that same date would continue to be regulated as a CISWI until January 31st. As stated above, this is an impermissible expansion of §129 requirements to a unit not combusting waste material. *See Chevron*, 467 U.S. at 842-43.

Response: This comment pertains to the CISWI rulemaking, and it is out of scope for this boiler rulemaking. Provided the commenter has submitted this comment to the CISWI rulemaking docket, the response to this comment will be provided there.

Commenter Name: Lorraine Gershman

Commenter Affiliation: American Chemistry Council (ACC)

Document Control Number: EPA-HQ-OAR-2002-0058-3510-A1

Comment Excerpt Number: 149

Comment: *EPA's 6-month Requirement Could Illegally Subject Units that No Longer Burn Solid Waste to § 112 and 129 Standards Simultaneously.*

Under §129(h)(2), Congress limited EPA's authority to regulate CISWI units by stating that "no solid waste incineration unit subject to performance standards under [CISWI – sections 111 and 129] shall be subject to standards under [NESHAP – section 112]." The recent ruling from the D.C. Circuit Court of Appeals highlighted the mutual exclusivity of §112 and §129. In *Portland Cement Ass'n v. EPA*, 2011 U.S. App. LEXIS 24577, at *12 n.2 (D.C. Cir. Dec. 9, 2011) the court notes that some cement kilns would be regulated under NESHAP and other cement kilns combusting solid waste "...would be subject to standards under the CISWI rules rather than under the NESHAP rules, since the two regimes are mutually exclusive. *See also, NRDC v. EPA*, 489 F.3d 1250, 1256 (D.C. Cir. 2007). The reconsidered CISWI proposal would subject some units that should be subject to regulation under §112 (e.g., boilers), when and because they are combusting traditional fuels, to both §129 and §112 emission limits because of their intermittent combustion of solid waste.

For example, the Boiler MACT rule applies to an ICI boiler or process heater, as defined in 40 C.F.R. §63.7575, that is a major source of hazardous air pollutants. 40 C.F.R. §63.7485. The Boiler MACT states in §63.7575 that a unit "combusting solid waste . . . is *not* a boiler." In other words, as soon as a major source unit subject to §129 regulation stops burning solid waste, it would be a combustion unit regulated by the Boiler MACT §112 standards. But under EPA's fuel-switching approach, the unit would continue to be a "solid waste incinerator," subject to §129 standards for at least 6 months after the unit stops burning waste. This 6-month overlap between the start of Boiler MACT applicability and the end of CISWI applicability is impermissible because it would subject a unit to both §129 and §112 standards in violation of those sections of the CAA and D.C. Circuit case law.

Fortunately, there is precedent for a fuel switching provision that is both lawful and workable, and would assure that a combustion unit is subject to either the CISWI or the Boiler MACT rule requirements at all times, but not to both simultaneously. The fuel switching provisions in the 2005 NESHAP for Hazardous Waste Combustors ("HWC MACT") have been in place for many years and are operating successfully. *See* 40 C.F.R. §§63.1200 et seq., 63.1206(b)(ii) & 63.1209(q). The HWC MACT allows units that intermittently combust hazardous waste to comply with either Subpart EEE, some other subpart promulgated under §112 or §129, depending on whether the unit is combusting hazardous waste. 40 C.F.R. §63.1206(b)(ii).⁴² In relevant part, the emission standards and operating requirements set forth in the HWC MACT do *not* apply "when hazardous waste is not in the combustion chamber" and the unit's compliance with other §112 or 129 requirements has been documented. *Id.*

The HWC MACT requires that if the unit is going operate under different modes of operation, the owner/operator must establish operating parameter limits for each mode. Additionally, the owner/operator must document in the operating record when the unit changes a mode of operation and begins complying with the operating limits for an alternative mode of operation. In order to operate under otherwise applicable requirements promulgated under §§112 or 129, the owner/operator must specify the otherwise applicable requirements as a mode of operation in its Documentation of Compliance; its Notification of Compliance; and its Title V permit application. These requirements include the otherwise applicable requirements governing emission standards, monitoring and compliance, notification, reporting and recordkeeping. *See* §63.1209(q)(1).

ACC recognizes that hazardous waste combustion units, unlike solid waste combustion units, are exempted from the definition of “solid waste incineration unit” in §129(g) so EPA is not *required* to regulate these units under § 129. Nonetheless, if EPA can offer regulatory flexibility for units that intermittently combust *hazardous* waste, it should certainly do the same for units that intermittently combust non-hazardous solid waste.

The regulatory approach taken in the HWC MACT could easily be adapted and applied permissibly under §129. This would ensure that when combusting a solid waste the unit is regulated under §129, and when combusting a traditional fuel it is regulated under §112. One of these strict regulatory regimes would be applicable at all times, there would be no regulatory gaps and no confusion as to which set of requirements apply and the burden would be on the owner/operator to ensure that it is in compliance with one of these regulatory regimes at all times.

[Footnote 42: When hazardous waste is not in the combustion chamber (i.e., the hazardous waste feed to the combustor has been cut off for a period of time not less than the hazardous waste residence time) and you have documented in the operating record that you are complying with all otherwise applicable requirements and standards promulgated under authority of sections 112 (e.g., 40 CFR part 63, subparts LLL, DDDDD, and NNNNN) or 129 of the Clean Air Act in lieu of the emission standards under §§ 63.1203, 63.1204, 63.1205, 63.1215, 63.1216, 63.1217, 63.1218, 63.1219, 63.1220, and 63.1221; the monitoring and compliance standards of this section and §§ 63.1207 through 63.1209, except the modes of operation requirements of § 63.1209(q); and the notification, reporting, and recordkeeping requirements of §§ 63.1210 through 63.1212.]

Response: This comment pertains to the CISWI rulemaking, and it is out of scope for this boiler rulemaking. Provided the commenter has submitted this comment to the CISWI rulemaking docket, the response to this comment will be provided there.

Commenter Name: Shannon S. Broome

Commenter Affiliation: Auto Industry Forum (AIF)

Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1

Comment Excerpt Number: 19

Comment: As a corollary, AIF urges EPA to clarify that the CISWI Rule does not apply to the combustion of LFG when combusted for control or as fuel in a boiler, *i.e.*, the combustion of

LFG is not a “contained gaseous material” and, therefore, it is not a “solid waste” and not regulated under the CISWI Rule. LFG is not a “solid waste” because, even if it considered to have been derived from “solid waste,” it is a newly generated material that has never been discarded. EPA should add clarifying language to that effect in the CISWI and NHSM Rules.¹³

[Footnote 13: The Boiler MACT Reconsideration Proposal already implies that EPA takes this position in that it includes LFG in the definition of “gaseous fuel” at the proposed § 63.7575. *See Boiler MACT Reconsideration Proposal*, 76 Fed. Reg. at 80,652. Moreover, EPA’s own outreach program recognizes LFG as a fuel. *See LMOP, supra.*]

Response: This comment pertains to the CISWI rulemaking, and it is out of scope for this boiler rulemaking. Provided the commenter has submitted this comment to the CISWI rulemaking docket, the response to this comment will be provided there.

Commenter Name: Shannon S. Broome

Commenter Affiliation: Auto Industry Forum (AIF)

Document Control Number: EPA-HQ-OAR-2002-0058-3512-A1

Comment Excerpt Number: 56

Comment: Coating Operation Control Devices: AIF Supports EPA’s Clarification and Confirmation that the CISWI Rule Does Not Apply to Burning Gaseous Materials Associated with Coating Operations; EPA Should Reinstate the Definitions of “Contained Gaseous Material” and “Solid Waste” for Clarity.

The NHSM Rule, issued contemporaneously with the CISWI Rule, purported to outline which secondary materials are classified as “solid waste” for purposes of determining whether the CISWI Rule may apply to units that combust those materials. In response to comments on the proposal for the NHSM Rule requesting a definition of “contained gas” consistent with its prior interpretation under the RCRA, EPA made certain statements that raised questions as to whether EPA was revising its long-standing interpretation that gas in pipelines is not a “contained gas” and thus not “solid waste” under RCRA. *See Responses to Comments Document on NHSM Rule*, at p. 213-14 (March 21, 2011), Docket Control No: EPA-HQ-RCRA- 2008-0329-1837. Although AIF noted that the definition of “CISWI unit” makes a distinction between the CISWI unit and the attached control device, AIF requested clarification from EPA that emissions streams from the various processes ducted to control devices, including those utilized by facilities owned and/or operated by AIF members, are not “solid waste,” *i.e.*, the air pollution control unit is *not* a “CISWI unit.” A May 13, 2011, letter from Suzanne Rudzinski, Director of EPA’s Office of Resource Conservation and Recovery, to Mr. Timothy Hunt, American Forest and Paper Association, set forth that EPA’s statements in the NHSM Response to Comments did “not change any previous EPA positions” and that EPA’s “previous statements and interpretations remain effective.” Docket No. EPA-HQ-RCRA-2008-0329-1854 (“Rudzinski Letter”). Based on that letter, AIF understood that the CISWI Rule does not apply to control units (and associated equipment)⁴⁰ that transport and burn captured gas, and that the gaseous materials combusted in the course of coating operations are not “solid wastes” under RCRA. AIF requested that EPA confirm this interpretation and clarify it in regulatory language. In the proposal, EPA acknowledges that the Rudzinski Letter caused confusion about whether EPA was changing its prior interpretation regarding the burning of gaseous materials and whether or not

such burning constitutes the treatment of a solid waste by burning. *See CISWI and NHSM Rules Reconsideration Proposal*, 76 Fed. Reg. at 80,472-73. Accordingly, EPA now clarifies that which it set forth in the Rudzinski Letter: EPA is not changing any of its prior interpretations; those prior interpretations remain effective on the issue of whether “contained gaseous material” is a solid waste. *See id.* Specifically, EPA restates that “burning of gaseous material, such as in fume incinerators (as well as other combustion units, including air pollution control devices that may combust gaseous material) does *not* involve treatment or other management of a solid waste as defined in RCRA section 1004(27).” *Id.* at 80,473 (emphasis added).

AIF appreciates and supports EPA’s clarification and confirmation in the proposal that the CISWI Rule does not apply to the burning of gaseous materials associated with coating operations. The proposal, however, still leaves several questions unanswered.

First, as conveyed in the reconsideration proposal, the regulations do not include a definition of “contained gaseous material.” While that definition is presently found at 40 C.F.R. §§ 60.2265 and 60.2875, the CISWI Rule as finalized on March 21, 2011, appeared to remove these definitions. *See CISWI Rule*, 76 Fed. Reg. at 15,761 (noting an amendment to § 60.2265 by, among other things, removing the definition of “contained gaseous material”); *id.* at 15,782 (same as to § 60.2875). The reconsideration proposal does not include any statements confirming or re-affirming the removal of the definitions. As a corollary, nor does it include any statements explicitly confirming that the definitions will remain part of the regulations or making any correction as to the apparent removal of the definitions in the CISWI Rule as finalized on March 21, 2011. EPA’s clarification and confirmation in the reconsideration proposal that the CISWI Rule does not apply to the burning of gaseous materials associated with coating operations suggests to AIF that EPA intended for the reconsideration proposal to reinstate the definitions of “contained gaseous material” into the CISWI Rule. To carry out that intent, however, EPA must actually reinstate those definitions into regulatory provisions of the final reconsideration rule. AIF urges EPA to take that action.

Second, reinserting the definition of “contained gaseous material” would not, by itself, resolve the concern in the regulatory community as to gas in pipelines being regulated as a “contained gaseous material” and thus as a “solid waste” under RCRA. This is because the reconsideration proposal does not appear to reverse the removal of the definition of “solid waste” from the CISWI Rule at § 60.2265. Without reinstating the definition of “solid waste,” the regulations cannot give effect to the definition of “contained gaseous material” (assuming EPA reinstates it) because “contained gaseous material” does not appear elsewhere in the CISWI Rule. Despite not appearing the definitions section, the term “solid waste” does appear in the following definitions in the reconsideration proposal: “[CISWI] unit,” “energy recovery unit,” “incinerator,” “small, remote incinerator,” “solid waste incineration unit,”⁴¹ and “waste-burning kiln.” *See CISWI and NHSM Rules Reconsideration Proposal*, 76 Fed. Reg. at 80,501-03. Each of these definitions as proposed modifies the term “solid waste” with reference to how the Administrator defines the term at 40 C.F.R. § 241. *See id.* At 40 C.F.R. § 241, the regulations set forth that “[s]olid waste means the term solid waste as defined in 40 CFR 258.2.”⁴² 40 C.F.R. § 241.2. The definition there is equivalent to the definition of “solid waste” that was deleted

from the CISWI Rule in the final rule of March 21, 2011.⁴³ *See* 40 C.F.R. § 258.2; *see also* 68 Fed. Reg. 57,518, 57,551 (Oct. 3, 2003) (comparable definition of “solid waste” in the CISWI Rule as then-finalized). This formulation of the definition derives from the definition of “solid

waste” in the Solid Waste Disposal Act at 42 U.S.C. § 6904(27), *i.e.*, RCRA § 1004(27). Without EPA reinstating the definition of “solid waste,” then, it would appear that a reinstated definition of “contained gaseous material” would control interpretation of the term “solid waste” in the CISWI Rule. To promote clarity across the CISWI and NHSM Rules, as well as understanding in the regulated community, however, EPA should reinstate the definition of “solid waste” into the CISWI Rule.⁴⁴

Reinstating both the “contained gaseous material” and “solid waste” definitions is necessary, given the uncertainty created by EPA in its response to comments on the NHSM Rule. As noted above, EPA states in the reconsideration proposal that it did not intend to create this uncertainty or change any of its previous positions regarding contained gas. *See CISWI and NHSM Rules Reconsideration Proposal*, 76 Fed. Reg. at 80,472-73. To that end, EPA conveys that the “burning of gaseous material, such as in fume incinerators (as well as other combustion units, including air pollution control devices that may combust gaseous material) does not involve treatment or other management of solid waste (as defined in RCRA section 1004(27)).” *Id.* The only way EPA can adequately give effect to its representations is reinstating the definitions of “contained gaseous material” and “solid waste.”

As a corollary, EPA must clarify that the CISWI Rule does not apply to the combustion of LFG, either when combusted for control or as fuel in a boiler, *i.e.*, the combustion of LFG is not a “contained gaseous material” and, therefore, it is not a “solid waste” and not regulated under the CISWI Rule. LFG is not a “solid waste” because, even if it considered to have been derived from “solid waste,” it is a newly generated material that has never been discarded. EPA should add clarifying language to that effect in the CISWI and NHSM Rules.⁴⁵

[Footnote 40: *E.g.*, regenerative thermal oxidizers used in coating operations.]

[Footnote 41: Note that there appears to be a typographical error in the proposed regulatory language for this definition such that it only includes the term “solid” where it appears that it should read “solid waste.”]

[Footnote 42: According to the regulations accompanying that definition, § 241 does not define “solid waste”; rather, they “identif[y] the requirements and procedures for the identification of solid wastes.” 40 C.F.R. § 241.1 (purpose).]

[Footnote 43: The definition reads as follows: *Solid waste* means any garbage, or refuse, sludge from a wastewater treatment plant, water supply treatment plant, or air pollution control facility and other discarded material, including solid, liquid, semi-solid, or contained gaseous material resulting from industrial, commercial, mining, and agricultural operations, and from community activities, but does not include solid or dissolved materials in domestic sewage, or solid or dissolved materials in irrigation return flows or industrial discharges that are point sources subject to permit under 33 U.S.C. 1342, or source, special nuclear, or by-product material as defined by the Atomic Energy Act of 1954, as amended (68 Stat. 923). *Id.* § 258.2.]

[Footnote 44: As an alternative, AIF requests that EPA clarify whether AIF correctly understands EPA’s intent as to “contained gaseous material” and “solid waste” in the CISWI Rule. ;

[Footnote 45: The Boiler MACT Reconsideration Proposal already implies that EPA takes this position in that it includes LFG in the definition of “gaseous fuel” at the proposed § 63.7575. *See*

Boiler MACT Reconsideration Proposal, 76 Fed. Reg. at 80,652. Moreover, EPA's own outreach program recognizes LFG as a fuel. *See LMOP, supra.*]

Response: This comment pertains to the CISWI rulemaking, and it is out of scope for this boiler rulemaking. Provided the commenter has submitted this comment to the CISWI rulemaking docket, the response to this comment will be provided there.

Commenter Name: Alicia Meads

Commenter Affiliation: National Association of Manufacturers (NAM)

Document Control Number: EPA-HQ-OAR-2002-0058-3515-A1

Comment Excerpt Number: 10

Comment: The NAM agrees with the EPA's decision not to apply the proposed incinerator MACT standards to small "burn-off ovens." 76 Fed. Reg. 80,460. In addition to the reasons identified by the EPA, it is not appropriate to categorize burn-off ovens as incinerators, as most burn-off ovens are not actually combusting material. Instead they use lower temperature processes such as melting or pyrolysis and are specifically designed to avoid flaming conditions, which would damage the parts being cleaned.

Response: This comment pertains to the CISWI rulemaking, and it is out of scope for this boiler rulemaking. Provided the commenter has submitted this comment to the CISWI rulemaking docket, the response to this comment will be provided there.

Commenter Name: Mary Sullivan Douglas

Commenter Affiliation: National Association of Clean Air Agencies (NACAA)

Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1

Comment Excerpt Number: 43

Comment: If the PM and mercury limits remain roughly as proposed for existing sources,⁴⁰ few sources will desire to be regulated under section 129. Most sources will argue that they get a "meaningful" contribution to the overall combustion process from what they burn. This will increase the level of disagreement over whether a material is a waste and may result in fewer sources burning waste materials. Some sources (with low CO levels) might find it in their interests to assert that they are incinerators rather than energy recovery units. Thus, the definitions of "solid waste" and "incinerator" may matter to a number of sources. EPA should also consider its proposed MACT rules in light of BACT determinations for similarly situated units and explain why emission limitations deemed "available" as BACT are orders of magnitude more stringent than the ("maximum achievable") MACT standards. A review of EPA's RACT/BACT/LAER clearinghouse reveals a number of BACT decisions for cement kilns that are far more stringent than EPA's proposed limits.⁴¹ In addition, EPA's control technologies guidelines for cement kilns,⁴² published under section 108 of the CAA, document the existence of cost-effective retrofit technologies available for control of SO₂ and NO_x in cement kilns. EPA seems to assume either that there are no cost-effective controls for these pollutants at cement kilns or that the CAA does not require MACT limits to be based on these controls. EPA should explain its rationale in greater detail and set forth a basis for any final decision it makes. EPA should review each of its proposed MACT limits to ensure that they reflect the application of maximum achievable technology, not merely the MACT floor. In addition, it would seem that

MACT should be more stringent than either GACT or BACT. Accordingly, MACT limits for cement kilns for SO₂ and NO_x should be at least as stringent as BACT limits for such units.

Moreover, the performance demonstrated by the best performing units suggests that existing sources, if equipped with MACT level technology, would be capable of far better performance than suggested by EPA's rules. Similarly, we note the very significant differences in the MACT limit that EPA applies to smaller units at area sources compared to similar units at major sources. Since the MACT limits for those units are presumed to meet the statutory effectiveness tests for MACT controls, unless the cost per ton for similar units at area sources is substantially different it would seem that the test is met at those sources as well.

[Footnotes]

(40) NO_x and SO₂ limitations under section 129 may also discourage combustion of solid waste. This issue can be addressed by EPA when it adopts emission limitations for large industrial units under Phase II of its Transport Rules.

(41) Many of these decisions are for new units, but are based on technologies suitable for retrofit (albeit at somewhat greater cost).

(42) See, http://www.epa.gov/ttn/catc/dir1/cement_updt_1107.pdf See also additional studies by Northeast States for Coordinated Air Use Management (NESCAUM) <http://www.nescaum.org/documents/ici-boilers-20081118->

[final.pdf/](http://www.nescaum.org/documents/hg-control-and-measurement-techs-at-us-pps_201007.pdf/); http://www.nescaum.org/documents/hg-control-and-measurement-techs-at-us-pps_201007.pdf/.

Response: This comment pertains to the CISWI rulemaking, and it is out of scope for this boiler rulemaking. Provided the commenter has submitted this comment to the CISWI rulemaking docket, the response to this comment will be provided there.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 18

Comment: EPA seeks comment on the provisions included in the final CISWI rule regarding changing fuels being combusted and thereby changing the status of a unit as an incinerator or boiler, particularly on whether the provisions should include further clarification on the timeline and regulatory requirements of a fuel switch. Additionally, EPA is soliciting comment on an alternative time period for switching frequency. 76 FR 80460.

CIBO opposes EPA's prescriptive approach to boiler or incinerator status. This constrained approach is not necessary to ensure compliance with the applicable standards. Instead, the constraints result in EPA governing economic decisions related to supply and demand, and deprive regulated sources the flexibility to make sound economic decisions related to their operations.

Response: This comment pertains to the CISWI rulemaking, and it is out of scope for this boiler rulemaking. Provided the commenter has submitted this comment to the CISWI rulemaking docket, the response to this comment will be provided there.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 19

Comment: The practical effects of the regulation are far-reaching. For example, if a facility burns a waste /fuel mix, which is typical, and is operating under the CISWI regulations, if for some reason the waste component of their fuel supply becomes unavailable, solid fuel boilers (e.g., coal) would not be able to meet the emission requirements under CISWI (e.g. sulfur dioxide) and would have to shut down operations (or find an alternate source of energy) until they are permitted to switch back to an appropriate standard for their solid fuel. Many waste streams are not available year round and their supply is dependent upon production schedules at other entities. Also, a facility may inadvertently burn a material that is a waste or later becomes classified as a waste, and might be forced to shut down or operate under the CISWI regulations for six months during periods while no waste is being burned. This presents an additional and significant risk to attempting to burn alternative fuels. Another complication is that many units do not fire solid waste until the unit is started up and at steady state.

To remedy these damaging effects, a provision should be added that allows a facility to elect to either (1) comply with CISWI at all times or (2) comply with CISWI while burning solid waste but comply with otherwise applicable standards under section 112 of the Clean Air Act while not burning solid waste. The Hazardous Waste Combustor MACT (see 40 CFR 63.1206(b)(1)(ii) and 63.1209(q)) provides a helpful referent.

This will also alleviate another problem caused by the EPA's decision that work practice standards are not adequate for the regulation of sources during their startup and shutdown periods. Because EPA has stated it cannot use work practice standards during periods of startup and shutdown, compliance with CO emission limits along with other parameters such as sorbent loading in spray dryer absorbers will be very problematic. EPA should resolve this problem by allowing sources that encounter these issues to elect to comply with section 112 standards during all times that solid waste are not being combusted or, alternatively, during just the startup and shutdown periods.

If a source elects one of these options, it would have to conduct all necessary performance testing and establish continuous compliance monitoring systems and recordkeeping systems to comply with both the section 129 (CISWI) and the section 112 rules. Facilities can easily document which mode of operation they are in (by tracking solid waste feed rates) and readily show compliance with the applicable standard. There are no compliance assurance issues with allowing this flexibility, as sources are able to demonstrate during what periods solid waste is in the combustor.

Response: This comment pertains to the CISWI rulemaking, and it is out of scope for this boiler rulemaking. Provided the commenter has submitted this comment to the CISWI rulemaking docket, the response to this comment will be provided there.

Commenter Name: Allison Watkins, Baker Botts
Commenter Affiliation: Class of '85 Regulatory Response Group
Document Control Number: EPA-HQ-OAR-2002-0058-3608-A1
Comment Excerpt Number: 4

Comment: The Class of '85 supports EPA's proposed clarification of the definition of biomass in the proposed reconsideration of the new source performance standards and emission guidelines for commercial and industrial solid waste incineration units,4 which would establish how bio-based fuels are treated under the Major Source Rule. The clarification will remove a barrier to expanding the use of several promising biomass fuel sources.

Response: This comment pertains to the CISWI rulemaking, and it is out of scope for this boiler rulemaking. Provided the commenter has submitted this comment to the CISWI rulemaking docket, the response to this comment will be provided there.

Commenter Name: Randal G. Oswald
Commenter Affiliation: Integrys Energy Group
Document Control Number: EPA-HQ-OAR-2002-0058-3659-A2
Comment Excerpt Number: 4

Comment: Integrys supports EPA's proposed clarification of the definition of biomass in the proposed reconsideration of the new source performance standards and emission guidelines for commercial and industrial solid waste incineration units, which would establish how bio-based fuels are treated under the Major Source Rule. The clarification will remove a barrier to expanding the use of several promising biomass fuel sources.

Response: This comment pertains to the CISWI rulemaking, and it is out of scope for this boiler rulemaking. Provided the commenter has submitted this comment to the CISWI rulemaking docket, the response to this comment will be provided there.

Commenter Name: Stuart A. Clark
Commenter Affiliation: State of Washington Department of Ecology
Document Control Number: EPA-HQ-OAR-2002-0058-3665-A2
Comment Excerpt Number: 3

Comment: We are pleased that the preamble to the proposed Commercial and Industrial Solid Waste Incineration (CISWI) rule indicates the rule is being modified to clarify which biomass fuels (i.e. waste wood from forest harvesting) are not solid waste. However, the rule amendment could make this more explicit by specifically listing these materials as fuels.

A key consideration when assessing whether a material meets the legitimacy criteria is determining whether the material has been "discarded". The regulated community would benefit by either adding a definition of "discarded" that is not ambiguous or by issuing a Clarification

Letter explaining how this determination will be made by the Agency. This is especially important when considering the status of materials collected through programs designed to divert useful materials from landfill disposal that can otherwise be processed into legitimate fuels or feedstock.

While acknowledging efforts to ensure expeditious review of petitions to the regional director for a non-waste determination, we believe the value of the opportunity for public comment outweighs the burden of a thirty day delay in completing the petition process. We are pleased that EPA proposed to segregate coal fired energy recovery units from other nonhazardous waste, biomass based energy recovery units under the CISWI rule. This segregation will provide much more appropriate alignment of hazardous air pollutant emission limits with the type of fuel.

Response: This comment pertains to the CISWI rulemaking, and it is out of scope for this boiler rulemaking. Provided the commenter has submitted this comment to the CISWI rulemaking docket, the response to this comment will be provided there.

Commenter Name: Mark Anthony

Commenter Affiliation: Alyeska Pipeline Service Company

Document Control Number: EPA-HQ-OAR-2002-0058-3684-A2

Comment Excerpt Number: 9

Comment: 1. Definition of Contained Gaseous Material.

At pg 80463 the reconsideration proposal states that EPA is "not changing its historical interpretation of what gases could be considered to be solid waste (Le., a 'contained gas')." In that same discussion EPA states that it has added back into CISWI the definition of "contained gaseous material." When we looked we could not find the definition in the regulatory text. Unless we missed it, it appears that EPA missed adding the definition back into regulatory text of the reconsideration proposal.

2. Contained Gas Policy for Regulated Gas Streams Combusted in a Boiler

With respect to EPA's historical interpretation of contained gas, Alyeska reviewed the RCRA documents that it is aware of that embody that interpretation and the CISWI response to comments. We are still concerned that a narrow reading of the contained gas interpretations and the response to comments may limit its application to fume incinerators (Le., air pollution control devices). We also are still concerned that EPA has not assured industry that gas that arises from

. an air pollution control device, or that is captured through a control device such as a vapor recovery system, that is then routed to and combusted in a boiler will not be considered a nonhazardous secondary material, unless it passes the burdensome legitimacy criteria. In the proposed Boiler rule on page 80652 there is a definition of "gaseous fuel" that includes process gases, which under that rule a facility should be able to rely upon to describe their combusted gas a fuel. However, in the CISWI rule there is no such definition or similar discussion. We refer you to the following response to comments for the earlier final CISWI rule, specifically the bolded text:

Comment [3b-B-4]:

Contained Gas --A limited number of commenters indicated that the final rule should contain a definition of "contained gaseous material." The statutory definition of solid waste includes "solid, liquid, semisolid or *contained gaseous material.*" 42 U.S.C. § 6903(27) (emphasis added). EPA has interpreted the term "contained gaseous material" to include gases in containers, but not gases flowing through pipes to combustion units. Under the June 4, 2010 Comments Document -NHSM Rule proposed revisions to the CISWI rule, the existing definition of solid waste will be removed, and the rule will rely upon the proposed definition of solid waste here (proposed 40 C.F.R. Part 241).

The commenters state that the preamble language in the proposed rule could be read to suggest that gaseous fuels are to be included in the Part 241 definition of solid waste. In discussing which traditional fuels are to be used for comparison purposes in applying the legitimacy criterion concerning contaminants, the proposed rule says:

"For example, if the boiler burns fuel oil, the level of contaminants to be compared would be the level of contaminants in fuel oil or other liquid traditional fuels that is or can be burned in such unit, while *for gas-fired boilers, the level of contaminants in the non-hazardous secondary material fuels would be compared to natural gas.*"

The commenter assumes that EPA does not intend to regulate gaseous fuels through this rule or otherwise under CAA section 129. Consistent with the statutory definition of solid waste and with EPA's approach in the 2000 CISWI rule, EPA should make clear that "contained gaseous material" is only meant to cover gas in a container when that container and its contents are combusted.

EPA's response: As a preliminary matter, EPA wishes to correct certain misconceptions in these comments. First, we wish to make it clear that the statement regarding secondary material fuels replacing natural gas in gas-fired boilers only refers to fuels that are secondary materials. It does not refer to a situation in which a gas-fired boiler can use, for example, refined fuel oil EPA is aware that fuel oil and gas may be used interchangeably in some boilers. The preamble statement, however, only applies to a secondary material, not a product fuel. Since on specification used oil is considered an alternative "traditional fuel," it would not be considered a secondary material.

Next, EPA also acknowledges that this rule does not apply to vented gas that is in no way contained and simply goes into the atmosphere. We are not dealing with whether such vented gases are subject to the definition of solid waste. Vented gas simply will not be used as a secondary material in any gas-fired boiler and thus, is not part of this rulemaking; nor is EPA reopening any rules regarding such vented gases.

Further, EPA is not considering viewpoints regarding how it regulates gases under the hazardous waste regulations -specifically, whether gases in pipelines are contained. The Agency needs to evaluate whether the non-hazardous secondary gaseous material that will be used as substitutes in gas-fired boilers are solid wastes, or not, under the statutory definition. EPA's determination in this rule is based on the plain language of the statute. This leads EPA to the situation covered in this rule. In the first place, we are unable to find any Agency reasoning supporting previous EPA

interpretations that only gases in containers may be considered "contained.» Based on the facts of this case, EPA cannot see how gaseous secondary material that is generated in any particular system and is somehow sent to a gas-fired boiler, even through a pipeline, can be considered an "uncontained gas." This el'en assumes that "uncontained gas" is not covered under the definition of solid waste, which EPA does not concede in this rulemaking. This would mean that a clean gas-fired boiler could still burn under CAA 112 secondary material that is handled through a seriously leaking pipeline, has little to no real fuel value, and is full of dirty contamination, simply because the material is not a "contained gas" under the definition of solid waste. EPA rejects any such formulation.

EPA appears to provide greater assurances later in the preamble when it refers to the letter to American Forest and Paper Association, 80473. Here EPA states that the burning of gaseous material in a combustion units, not limited to air pollution control devices is not an a form of treatment or other management of solid waste. This certainly is helpful. Nonetheless this is a very important issue and one we would like as much certainty as possible about. The boilers at the Valdez Marine Terminal burn vapors (gases) generated from storage tanks and the loading of tankers. These vapors consist predominately of hydrocarbon vapors and a limited amount of stack gas from the tankers and the boilers that is used as an inert gas for these vapor collection systems. We wish to utilize the control device exemption in Boiler MACT. but arc concerned that EPA may in turn classify the vapors as solid waste or at least require that we must demonstrate the vapors are non-traditional fuels through the legitimacy criteria.

Logically, it makes sense that a boiler that acts as a control device under some other part, in our case marine loading and organic liquid distribution MACTs, should be exempt from CISWI. Indeed as we discussed above Boiler MACT provides an exemption for boilers used as control devices provided the gases contribute more than 50% of the boiler's heat input. To eliminate this confusion and future compliance and Title V permitting risks it would be ideal ifEPA simply created an exemption from CISWI for air pollution control devices and boilers and process heaters that are used as control devices under Parts 63, 61 and 60. Alternatively, EPA could as a matter of interpretation make such a statement in the preamble or response to comments.

3. Exclusion of Cyclonic Burn Barrels, Soil Treatment Units, Laboratory Analysis Units and Space Heaters from CISWI

Alyeska strongly supports the retention of the exemptions for cyclonic burn barrels, soil treatment units, laboratory analysis units, and space heaters. Since the function and operation of these types of units is fundamentally different than incinerators contemplated under the Act, Alyeska supports EPA's decision to exclude them from CIS WI.

4. Alyeska Supports the Comments of the Alaska Oil and Gas Association (AOGA)

Alyeska is a member of AOGA and strongly supports AOGA's comments.

Response: This comment pertains to the CISWI rulemaking, and it is out of scope for this boiler rulemaking. Provided the commenter has submitted this comment to the CISWI rulemaking docket, the response to this comment will be provided there.

1C. Out of Scope: Area Source Boilers

Commenter Name: Michael Bradley

Commenter Affiliation: The Clean Energy Group

Document Control Number: EPA-HQ-OAR-2002-0058-3495-A1

Comment Excerpt Number: 11

Comment: In general, the Clean Energy Group supports the changes EPA made to the area source rule between the proposed and final rules.

Startup and Shutdown

EPA proposes to revise the work practice standards for startup and shutdown to include a definition of startup and shutdown as well as to standardize requirements. Startup would be defined as the period between no combustion and 25 percent load, and shutdown would be between 25 percent load and no combustion. EPA requests comment on the need for and an appropriate duration limit for startup and shutdown periods during which numeric emission limits do not apply. The Clean Energy Group agrees with the need for a definition of startup and shutdown in light of the final rule's use of work practices for these periods. However, rather than 25 percent load, which may be inappropriate for many units, we recommend EPA alter the definition of startup to reflect unit-specific considerations, such as defining the end of startup as when the unit reaches the minimum safe operating load or when compliance with Title V emission limits is reached. Similarly, EPA could define shutdown as the period of time from when a unit reduces load with the intent to shut down and ends with the cessation of combustion of fuel. This would avoid defining as "shutdown" those circumstances where units may need to operate at a level below 25 percent, but above the minimum safe operating load.

In this way, EPA would utilize definitions already incorporated into existing air quality operating permits. Typically, these definitions are jointly established by the responsible air permitting authorities and the individual facility because startup and shutdown periods are somewhat unique to each boiler design. Below the unit-specific "normal operating mode" is when startup and shutdown requirements should apply. We recommend that EPA not numerically define startup and shutdown in the final rule, and instead defer to the definitions contained in currently active air quality operating permits issued by local and/or state air permitting agencies.

Additionally, EPA proposed to require that new boilers with heat input capacity greater than 10 MMBtu per hour that are biomass-fired or oil-fired must comply with work practice standards to minimize the boiler's startup and shutdown periods following the manufacturer's recommendations, or the manufacturer's recommendations for a unit of similar design. As noted above, we recommend revising the definition of startup and shutdown to allow for individual unit variation.

Synthetic Area Sources

Partially as a result of this rulemaking, we expect that many sources will seek to qualify as area sources if they are able, including through permit limitations. For example, an oil-fired unit that is currently a major source may reduce permitted potential to emit (PTE) through a permit limit on quantity of oil combusted. Particularly during the upcoming time period when existing area

source units are subject to requirements, while major source units are not, clarification on the timing of notification and compliance demonstration requirements is necessary. In the area source rule, § 63.11225(a)(2) states that "As specified in § 63.9(b)(2), you must submit the Initial Notification no later than 120 calendar days after May 20, 2011 or within 120 days after the source becomes subject to the standard." However, EPA proposes to amend § 63.11210(g) to clarify the compliance demonstration requirements for units that switch subcategories as the result of a physical modification or fuel switch. We request clarification as to which requirement governs newly-limited synthetic area sources, and specifically when notification requirements are due.¹ If § 63.11210(g) is intended to include synthetic area sources, we recommend EPA revise the language of § 63.11210(g) to clarify (1) that permit limits are included, and (2) the 180 days to demonstrate compliance includes units that switch from the major source rule to the area source rule. For example, the text could read (bold denotes additions and strikethroughs deletions):

(g) For affected boilers that switch fuels, or make a physical modification to the boiler, or take a permit limit that results in the applicability of a different subcategory or boiler NESHAP (e.g., a boiler that was previously subject to the major source rule at Subpart DDDDD), you must demonstrate compliance within 180 days of the effective date of the fuel switch, OF physical modification, or permit limit consistent with § 63.11225(g).

However, if § 63.11210(g) is not intended to include area sources created through permit conditions, we recommend that § 63.11210(g) clarify that the shorter timeline in § 63.9(b)(2) governs these sources. For example,

(g) For affected boilers that switch fuels or make a physical modification to the boiler that results in the applicability of a different subcategory, you must demonstrate compliance within 180 days of the effective date of the fuel switch or physical modification consistent with § 63.11225(g). However, if you become newly-subject to Subpart JJJJJ as the result of a permit condition (e.g., as a synthetic area source), you must comply with the requirements of § 63.9(b)(2).

Revisions to Initial Tune-up Requirement

EPA proposes that all existing boilers would have two years (by March 21, 2013) to demonstrate initial compliance. However, we do not expect the majority of sources to be able to take advantage of this proposed flexibility due to the timing of the proposal. The final rule requires area sources to complete this requirement by March 21, 2012, which is just one month after comments for these proposals close. As we do not expect EPA to complete review of comments and finalize the rule in one month, if EPA intends to finalize this change, the Agency should immediately issue a 90-day stay notice under Clean Air Act section 307(d)(7)(B).² Alternatively, we understand EPA is considering issuing a No Action Assurance letter, stating that the Agency would not enforce this provision. Either way, we expect this change will not provide the intended flexibility for the vast majority of sources that seek to ensure compliance with the final rule.

There are many instances where boiler operation may be too irregular to qualify as seasonal use, but run infrequently enough that a tune-up would be due while the unit is not operational, including at nuclear facilities. The final area source rule states that boilers due for a tune-up while they are not operating are not required to run the boiler only for the tune-up. Boilers in these situations would be required to conduct the tune-up within one week of startup. It does not

appear that the proposed reconsideration seeks to alter this provision; however, the Clean Energy Group expresses support for and encourages EPA not to alter this common-sense provision that eliminates unnecessary boiler operation and associated emissions. One week in which to complete the tune-up is reasonable and in line with state requirements (see, for example, New Jersey's code at 7:27-19.4(c), which allows seven days from initial operation for boilers not running when combustion adjustments are due).

Title V Implications

The final rule exempts all area sources from Title V permitting as a result of this rule. In other words, this rule alone would not trigger Title V requirements for an area source. The proposed rule required Title V permits for major sources of HAPs that became area sources by installing controls after 1990. However, EPA determined in its review of the record that it lacked sufficient information to distinguish these sources from other area sources. Thus, in the final rule, EPA is no longer requiring any units to obtain Title V permits as a result of this rule. Sources would need a Title V permit if they are subject to Title V for another reason. The Clean Energy Group supports this decision, which will allow both permitting authorities and covered sources to focus on the larger emitters, allowing for more efficient and effective emissions reductions.

Additional Subcategories

EPA proposes to create a new subcategory for seasonally-operated boilers, which would be subject to a tune-up requirement every five years after the initial tune-up prior to the compliance date. EPA also proposes to exempt temporary boilers, as was done in the final rule for major sources. We agree that temporary boilers should be exempted from both rules. We also support the creation of the seasonally-operated boiler subcategory, which, like many of the changes, will reduce requirements on boilers that operate infrequently or otherwise are likely to be insubstantial sources of HAPs. EPA proposes that seasonal boilers would include boilers that undergo "a shutdown for a period of at least 7 consecutive months (or 210 consecutive days) due to seasonal market conditions." However, many seasonal boilers are subject to separate regulatory requirements that they be officially available for longer periods. For example, in New York City and other cities in colder climates, heating is required to be available from October 1 to May 31. Other jurisdictions may have differing seasons depending on local needs. Thus, we recommend that EPA consider a wider range of seasonal definitions, or allow for a three-year rolling average of actual months of operation, without requiring a permit limit restricting months of availability.

Clarification of Applicability and Implementation Requirements

EPA proposes to amend the natural gas curtailment definition to clarify that it does not include normal market price fluctuations but would include on-site emergencies and equipment failures and is applicable to all gaseous fuels. This seems to be a clarification of rather than a change to the final rule, which we support.

Compliance Monitoring Flexibility

We support EPA's proposed revisions to compliance monitoring, including the use of CO CEMS, a 30-day rolling average for parameter monitoring and demonstrating compliance with operating

limits, and decreasing the tune-up requirement for small (<5 MMBtu/year) units to every five years, with the initial tune-up by the compliance date.

[Footnote 1: We have contacted Office of Air Quality Planning and Standards (OAQPS) and the Office of Enforcement and Compliance Assurance (OECA) with this question.]

[Footnote 2: The preamble to the proposed reconsideration states that if "the Agency has not taken final action on the initial compliance date for tune-ups prior to the date (March 21, 2012) for initial compliance, we could stay the effectiveness of the rule for 90 days, as allowed under CAA section 307(d)(7)(B), so that the Agency could complete reconsideration" (76 FR 80535, emphasis added). This statement on the compliance deadline is ambiguous.]

Response: This comment pertains to the area source boiler rulemaking. Provided the commenter has submitted this comment to the area source boiler rulemaking docket, the response to this comment will be provided there.

Commenter Name: Timothy Serie

Commenter Affiliation: American Coatings Association (ACA)

Document Control Number: EPA-HQ-OAR-2002-0058-3502-A1

Comment Excerpt Number: 1

Comment: ACA generally supports the following proposed changes in the Area Source Boiler rule:

1. Proposal to exempt temporary boilers;
2. Proposal to require an initial tune-up by March 21, 2014 and revision to the requirement for subsequent tune-ups only for oil-fired boilers equal to or less than 5 MMBtu/hr. to tune-up once every five years; however, EPA should extend the deadline for the initial tune-up to three years from promulgation of the March 2011 final rule in order to allow companies adequate time to complete the initial tune-ups and also to harmonize rule compliance dates for existing sources;
3. Revised definition of natural gas curtailment to clarify that a curtailment does not include normal market fluctuations in the price of gas that are not associated with periods of supplier delivery restrictions; however, the term "halted" may be interpreted to interfere with existing contractual obligations and therefore is too restrictive. ACA recommends that EPA incorporate the language changes suggested by the American Chemistry Council (ACC);
4. Revised averaging time from 12-hour average times to 30 days in order to address variability;
5. EPA's decision not to require Title V permits for area source boilers;
6. Proposal to exclude electric and residential boilers from the rule;
7. Proposal that process heaters are excluded from the definition of boilers;
8. Clarification that the emission limits in Table 1 do not apply during periods of startup and shutdown; EPA should, however, clarify that the operating limits set forth in Table 3 do not apply during startup and shutdown as well.

Response: This comment pertains to the area source boiler rulemaking. Provided the commenter has submitted this comment to the area source boiler rulemaking docket, the response to this comment will be provided there.

Commenter Name: Timothy Serie
Commenter Affiliation: American Coatings Association (ACA)
Document Control Number: EPA-HQ-OAR-2002-0058-3502-A1
Comment Excerpt Number: 18

Comment: ACA generally supports the following proposed changes to the MACT and area source boiler rules: Area source – EPA proposal to remove process heaters from the energy assessment requirement;

Response: This comment pertains to the area source boiler rulemaking. Provided the commenter has submitted this comment to the area source boiler rulemaking docket, the response to this comment will be provided there.

Commenter Name: Timothy Serie
Commenter Affiliation: American Coatings Association (ACA)
Document Control Number: EPA-HQ-OAR-2002-0058-3502-A1
Comment Excerpt Number: 26

Comment: *GACT* Emission Limits for Biomass and Oil-Fired Boilers

ACA supports EPA's determination that the final standards for biomass and oil-fired standards should be based on *GACT* and not *MACT*, as EPA did in the final rule, and requests EPA propose necessary revisions to the biomass and oil-fired standards that are based on *GACT*.

Response: This comment pertains to the area source boiler rulemaking. Provided the commenter has submitted this comment to the area source boiler rulemaking docket, the response to this comment will be provided there.

Commenter Name: Arthur N. Marin
Commenter Affiliation: Northeast States for Coordinated Air Use Management (NESCAUM)
Document Control Number: EPA-HQ-OAR-2002-0058-3506-A1
Comment Excerpt Number: 3

Comment: NESCAUM urges the EPA to create a new subcategory for biomass electric utility steam generating units (EGUs) of 25 MW or greater and establish emissions standards for these units at a *MACT* level of control consistent with how EGUs powered by other fuels are regulated. Though most types of EGUs have a separate *MACT* rule regulating them, EGUs that burn biomass fuel do not. Therefore, biomass EGUs with emissions below the major source threshold will be regulated as area source boilers, which is an inappropriate classification. There are many such sources that fall into this subcategory; in the NESCAUM region alone, at least a dozen facilities fall into this category and are subject only to area source requirements.

Response: This comment pertains to the area source boiler rulemaking. Provided the commenter has submitted this comment to the area source boiler rulemaking docket, the response to this comment will be provided there.

Commenter Name: Arthur N. Marin

Commenter Affiliation: Northeast States for Coordinated Air Use Management (NESCAUM)

Document Control Number: EPA-HQ-OAR-2002-0058-3506-A1

Comment Excerpt Number: 4

Comment: Unlike the major source boiler rule, the area source rule has created categories that are too large, and include a broad variety of boiler types that are not comparable. The current and proposed requirements for existing and new biomass boilers with heat input higher than 30 MMBtu/h do not adequately address the potential impacts and reductions that could be achieved by these very large units captured under the area source rule. Therefore, the NESCAUM states urge that the EPA develop a subcategory for biomass EGUs of 25 MW or greater that include appropriate emission limits and testing requirements as required for similar sized units firing liquid fuels and coal.

Response: This comment pertains to the area source boiler rulemaking. Provided the commenter has submitted this comment to the area source boiler rulemaking docket, the response to this comment will be provided there.

Commenter Name: Arthur N. Marin

Commenter Affiliation: Northeast States for Coordinated Air Use Management (NESCAUM)

Document Control Number: EPA-HQ-OAR-2002-0058-3506-A1

Comment Excerpt Number: 5

Comment: NESCAUM is providing numerical emissions limits typical of individual permitted biomass EGU sources in New Hampshire (specifically, for PSNH Schiller and Pinetree Power, Tamworth) and Massachusetts (based on the Renewable Portfolio Standard) as a possible basis for emission limits for national implementation. NESCAUM suggests the limit of 0.1 pounds per MMBtu (lb/MMBtu) for CO and 0.012 lb/MMBtu for PM. NESCAUM notes that these limits are contingent on the biomass being clean and uncontaminated (rather than wood waste fuel).

Response: This comment pertains to the area source boiler rulemaking. Provided the commenter has submitted this comment to the area source boiler rulemaking docket, the response to this comment will be provided there.

Commenter Name: Arthur N. Marin

Commenter Affiliation: Northeast States for Coordinated Air Use Management (NESCAUM)

Document Control Number: EPA-HQ-OAR-2002-0058-3506-A1

Comment Excerpt Number: 7

Comment: In the area source boiler rule reconsideration (76 FR 80538, Section IV.M. "Title V Permitting Requirements"), the EPA is proposing to retain the existing language at 40 CFR 63.11194(e) to exempt area source boilers from the requirement to obtain a Title V permit. The

EPA is proposing this exemption for all area source boilers: both “natural” area sources, i.e., sources that have potential to emit below the major source threshold without any control technologies; and “synthetic” area sources that avoided a major source determination because of installed control technology or instituted work practices to reduce emissions. The EPA requested comment on this exemption in light of a petition filed by the Sierra Club (Docket ID: EPA-HQ-OAR-2006-0790-2359) to reconsider the EPA’s decision to grant this exemption.

The existing language of 40 CFR 63 Subpart JJJJJ clearly states that an area source is exempt from the requirement to obtain a Title V permit irrespective of how or when the source became an area source subject to the subpart. We agree with the proposal to maintain this exclusion from Title V permitting. Facilities subject to Title V permitting requirements have additional administrative and financial burdens, and subjecting facilities to Title V permitting requirements solely because of previous source emissions will not result in further air quality benefits so long as clear and enforceable area source permits or regulatory limits are in place.

More importantly, retaining an exemption from Title V permitting requirement will create an incentive for major sources to reduce emissions below the major source threshold (10 or 25 tons per year) and thereby avoid the Title V permitting requirements. This source category (i.e., boiler units) is particularly likely to benefit from the incentive to avoid Title V because units in this category are not typically the units that cause the source to be major. Those sources that are major will be more likely to reduce emissions below the major source threshold through fuel switching or installation of control technologies in order to avoid Title V requirements. Therefore, NESCAUM recommends that the EPA retain the exemption for area source boilers from Title V permitting requirements when appropriate so as to not place unnecessary effort upon these sources and encourage enforceable emission reductions.

Response: This comment pertains to the area source boiler rulemaking. Provided the commenter has submitted this comment to the area source boiler rulemaking docket, the response to this comment will be provided there.

Commenter Name: Arthur N. Marin

Commenter Affiliation: Northeast States for Coordinated Air Use Management (NESCAUM)

Document Control Number: EPA-HQ-OAR-2002-0058-3506-A1

Comment Excerpt Number: 17

Comment: In its reconsideration of the final rule for area sources, the EPA proposes emission limits for biomass-fired boilers with heat input capacity between 10 and 30 MMBtu/h and over 30 MMBtu/h (76 FR 80548, Table 1 to Subpart JJJJJ of Part 63—Emission Limits). The NESCAUM states are concerned that failing to establish numeric emission limits for biomass-fired boilers between 1.6 MMBtu/h and 10 MMBtu/h will result in greater HAP emissions from sources in this category in the northeast region, and this may have detrimental impacts on sensitive population groups. According to a Biomass Energy Resource Center (BERC) database on small wood-fired boilers, most (95 of 150, or 63 percent) of the small wood boilers in the nation are installed at schools or hospitals.¹ The US Forest Service’s “Fuels for Schools” program has identified schools and hospitals as prime candidates to switch to biomass fuels. According to an analysis by BERC, in Wisconsin alone there are 200 to 300 schools using natural gas boilers that could economically and feasibly switch to biomass boilers.² Also

according to BEREC (2008), 30 percent of school children in Vermont attend schools heated with wood-fired boilers, yet only a handful of those boilers are required to meet an emission limit or undergo a single performance test. With the potential large increase in the use of small biomass boilers, NESCAUM anticipates significant emissions from these sources.

[Footnote]

(1) BEREC, Database Search Tool. Available at: <http://www.biomasscenter.org/database/database-search-tool.html>. Accessed: February 10, 2012.

(2) BEREC, Heating with Biomass, 2008. Available at http://www.biomasscenter.org/images/portfolio/pdfs/wi_school_wood_energy.pdf.

Response: This comment pertains to the area source boiler rulemaking. Provided the commenter has submitted this comment to the area source boiler rulemaking docket, the response to this comment will be provided there.

Commenter Name: Arthur N. Marin

Commenter Affiliation: Northeast States for Coordinated Air Use Management (NESCAUM)

Document Control Number: EPA-HQ-OAR-2002-0058-3506-A1

Comment Excerpt Number: 18

Comment: NESCAUM requests that the EPA create a new subcategory and establish emission limits for smaller biomass units. Small institutions like schools and hospitals are increasingly installing new, smaller biomass that are cleaner (e.g., those with multistage combustion) that do not need additional control technologies to avoid major source classification. A study by the New York State Energy Research and Development Authority (NYSERDA) found that high efficiency units can achieve an emissions performance level less than 0.1 lb/MMBtu without the use of any control device. Another study looking at biomass boilers installed under the Fuels for Schools program found that the range of performance varied significantly from 0.15 lb/MMBtu to 0.9 lb/MMBtu for a variety of biomass boilers. The EPA has not performed an adequate analysis to determine if a baseline performance standard should be required for all biomass boilers. Furthermore, the EPA has announced its intent to develop an emission standard for residential biomass boilers. If an emission standard is feasible for residential biomass boilers, it highlights not only the feasibility of emissions standards for small industrial, commercial, and institutional boilers, but the necessity of regulation so as not to create a void for these emission sources.

Response: This comment pertains to the area source boiler rulemaking. Provided the commenter has submitted this comment to the area source boiler rulemaking docket, the response to this comment will be provided there.

Commenter Name: Arthur N. Marin

Commenter Affiliation: Northeast States for Coordinated Air Use Management (NESCAUM)

Document Control Number: EPA-HQ-OAR-2002-0058-3506-A1

Comment Excerpt Number: 20

Comment: In its reconsideration of the final area source rule, the EPA is proposing to create a new subcategory for seasonally operated boilers. Boilers in this subcategory would be required, under an amended 40 CFR 63.11223, to complete a tune-up every five years instead of every two years, as required by non-seasonal boilers (76 FR 80534-5). The proposed definition of a seasonal boiler is:

Seasonal boiler means a boiler that undergoes a shutdown for a period of at least 7 consecutive months (or 210 consecutive days) due to seasonal market conditions. This definition only applies to boilers that would otherwise be included in the biomass subcategory or the oil subcategory.

NESCAUM is concerned that this seasonal boiler definition creates an opportunity for facilities with boilers used as heating units during the heating season to claim that they are “seasonal units,” although that is not the EPA’s stated intent. Boilers operating from November through March (i.e., that are shut down between April and October) might qualify as seasonal units under the proposed language and operate under the reduced tune-up requirements. Therefore, NESCAUM does not support the creation of a seasonal use category.

NESCAUM proposes that the EPA create a “limited use” subcategory that would serve to fulfill EPA’s intent to include facilities that are used on a more limited basis than units operated year-round. The limited use subcategory would be similar to the limited use subcategory described in the major source rule (76 FR 80609), specifically applying to units operating less than 10 percent of the hours in a year. This has the benefit of being consistent with the major source rule approach, and similar boilers would be treated the same way in different categories.

Response: This comment pertains to the area source boiler rulemaking. Provided the commenter has submitted this comment to the area source boiler rulemaking docket, the response to this comment will be provided there.

Commenter Name: Arthur N. Marin

Commenter Affiliation: Northeast States for Coordinated Air Use Management (NESCAUM)

Document Control Number: EPA-HQ-OAR-2002-0058-3506-A1

Comment Excerpt Number: 21

Comment: *Demonstrating Compliance with the Work Practice and Management Practice Standards under the Area Source Rule*

In its reconsideration of the final area source rule (76 FR 80540), the EPA is proposing to require that boiler tune-ups use the same type of fuel that provided the majority of the heat input to the boiler over the previous year. This closes a potential loophole for boilers that have the capability of burning multiple types of fuel to circumvent emissions limits by burning cleaner fuel for the compliance demonstration but burning dirtier fuel under typical operation. NESCAUM supports this change because it will create clearer tune-up protocols for regulators and regulated entities and reduce emissions.

Response: This comment pertains to the area source boiler rulemaking. Provided the commenter has submitted this comment to the area source boiler rulemaking docket, the response to this comment will be provided there.

Commenter Name: Arthur N. Marin
Commenter Affiliation: Northeast States for Coordinated Air Use Management (NESCAUM)
Document Control Number: EPA-HQ-OAR-2002-0058-3506-A1
Comment Excerpt Number: 26

Comment: In its area source rule reconsideration, the EPA proposed to amend 40 CFR 63.11196 to specify that all existing boilers subject to the tune-up requirement would have two years (by March 21, 2013) in which to demonstrate initial compliance, instead of one year to demonstrate initial compliance. In addition, the EPA requested comment on whether the initial compliance period for the tune-up requirement should be extended to three years (i.e., until March 21, 2014) (76 FR 80535).

Compliance with the March 21, 2012 deadline is logistically challenging for area sources and tune-up technicians given the short timeline, large universe of sources, and unfamiliarity with requirements under this rule. Therefore, NESCAUM supports extending the compliance period for the initial tune-up requirement to three years, until March 21, 2014.

Response: This comment pertains to the area source boiler rulemaking. Provided the commenter has submitted this comment to the area source boiler rulemaking docket, the response to this comment will be provided there.

Commenter Name: Arthur N. Marin
Commenter Affiliation: Northeast States for Coordinated Air Use Management (NESCAUM)
Document Control Number: EPA-HQ-OAR-2002-0058-3506-A1
Comment Excerpt Number: 27

Comment: NESCAUM supports efforts to have facilities conduct energy assessments in order to identify cost-effective, energy conservation measures on boilers larger than 1.6 MMBtu/h. NESCAUM agrees with the specific requirements and clear language for what constitutes an energy assessment, which NESCAUM had commented on previously. To ensure that energy assessments lead to tangible improvements in energy use and emissions, NESCAUM encourages the EPA and the states to work with facilities to implement cost-effective improvements identified in the energy assessment. Furthermore, NESCAUM recommends that the EPA work with agencies to establish clear guidelines as to what constitutes a cost-effective energy efficiency improvement.

Response: This comment pertains to the area source boiler rulemaking. Provided the commenter has submitted this comment to the area source boiler rulemaking docket, the response to this comment will be provided there.

Commenter Name: James Johnson
Commenter Affiliation: United States Beet Sugar Association (USBSA)
Document Control Number: EPA-HQ-OAR-2002-0058-3508-A1
Comment Excerpt Number: 1

Comment: EPA Should Expand the Current Seasonal Subcategory or Create a Separate Subcategory for Agricultural, Seasonal Boilers In the reconsideration of the area source Boiler rule, EPA acknowledged that it is appropriate to treat boilers that are operated on a seasonal basis differently from boilers that run continuously all year long. Boilers that run on a partial schedule have less overall environmental impact and can often tie their use to seasonal agricultural production. Boilers located at sugarbeet processing facilities fall into such a seasonal use category because they are only used for a finite agricultural season. The average use is less than 32 weeks, during which sugarbeets are being processed into granulated sugar. Over eighty percent of the boilers at sugarbeet processing facilities operate eight months or less per year. The USBSA recommends that EPA build upon the differentiation for seasonal sources already present in the reconsideration of the area source rule to either include such boilers in the seasonal subcategory or create a separate subcategory for seasonal, agricultural boilers that are located in remote locations and tied to the production of a crop. EPA has broad authority to subcategorize sources, and therefore, the agency is strongly supported in creating an agricultural, seasonal boiler subcategory. Indeed, expanding or creating an additional subcategory is an effective way to avoid unnecessarily costly emissions standards while still effectively protecting human health. The Clean Air Act (CAA) requires that EPA publish a list of “all categories and subcategories of major sources and area sources” of HAP.⁵ In creating such a list, EPA is required to be consistent with the categories created for New Source Performance Standards (NSPS) and Prevention of Significant Deterioration (PSD) programs, only “to the extent practicable.” Indeed, the statute gives EPA significant discretion in the creation of additional subcategories “as appropriate.” No other place in section 112 of the CAA speaks to or limits EPA’s abilities to create subcategories when appropriate. Courts also have found that the agency’s ability to subcategorize sources is quite broad and is limited only by the general reasonableness to which all agencies must adhere.⁶ In addition, EPA itself has acknowledged that it should address the creation of subcategories on an “as appropriate” basis, with the understanding that “each HAP emitting industry presents its own unique situation and facts to be considered.”⁷ EPA already has created subcategories based on use and on geography,⁸ and thus such additional subcategories would simply be an expansion of what the agency already has done, using the same rationale.

Expanding the existing seasonal subcategory or creating a new subcategory for seasonal boilers located in agricultural areas where sugarbeets are grown is an appropriate addition to the Boiler Rules because it supports differential regulation based on the actual impact of these boilers. In the case of the boilers used in sugarbeet processing, the intermittent nature of the use as well as the agricultural location of the boilers reduces the need to require the controls that would be necessary for a boiler operating in a more densely populated area with year-round use. By instituting management practices standards for such boilers, EPA will ensure that human health is adequately protected while also reducing the need for expensive controls that are not cost-effective because of the limited nature of the boiler use.

Response: This comment pertains to the area source boiler rulemaking. Provided the commenter has submitted this comment to the area source boiler rulemaking docket, the response to this comment will be provided there.

Commenter Name: James Johnson

Commenter Affiliation: United States Beet Sugar Association (USBSA)

Document Control Number: EPA-HQ-OAR-2002-0058-3508-A1

Comment Excerpt Number: 2

Comment: The affected boilers used to process sugarbeets are located in agricultural areas of the United States (MI, MN, ND, NE, MT, ID, CO, WY) away from large population centers (see Attachment A). Sugarbeet processing facilities are located near the agricultural fields where the sugarbeets are grown in order to minimize transportation, and thus concerns about HAP emissions from these boilers are minimal and such facilities pose a lower risk to public health. Because of the agricultural and seasonal nature of the sugarbeet processing facilities, there is significant justification for EPA to distinguish such boilers when finalizing the Boiler Rules. EPA has previously made distinctions between appropriate controls in areas that are heavily populated and those that are in remote areas when establishing requirements under section 112, such as in the Oil and Gas MACT. In making such distinctions, the agency has acknowledged the differential impacts that can occur from area sources that are located near population centers and near many other sources of HAP. Conversely, in sparsely populated areas where there are few sources of HAP, health impacts from these HAP emissions are greatly reduced. The section of the CAA that addresses area sources, in particular, is heavily focused on population centers. CAA section 112(k)(1) requires a finding that “emissions of hazardous air pollutants from area sources that may individually, or in the aggregate, present significant risks to public health in urban areas.” It is appropriate, therefore, and consistent with section 112(k) for EPA to regulate those sources located in agricultural areas, especially those classified as area sources, differently from sources located in more densely populated urban centers. Furthermore, expansion of the seasonal subcategory to include these boilers is in keeping with the other subcategories established in the Boiler Rules. EPA already has created subcategories based on geographical distinctions in the Boiler Rules. The rules currently have continental and non-continental subcategories, and distinctions based on the non-urban nature of the source stem from the same logic already being employed by the agency. EPA has broad discretion to subcategorize based on the agricultural locations of the boilers used for processing sugarbeets and doing so would be an appropriate balancing of economic and environmental concerns.

Response: This comment pertains to the area source boiler rulemaking. Provided the commenter has submitted this comment to the area source boiler rulemaking docket, the response to this comment will be provided there.

Commenter Name: James Johnson

Commenter Affiliation: United States Beet Sugar Association (USBSA)

Document Control Number: EPA-HQ-OAR-2002-0058-3508-A1

Comment Excerpt Number: 3

Comment: In addition to the remote nature of the USBSA members’ boilers, such boilers are used only on a seasonal basis. Because the boilers are tied to the production of an agricultural product, they are used only during the season for processing sugarbeets into granulated sugar. There is no other market for sugarbeets other than being processed into granulated sugar, and the sugarbeets must be processed in a timely manner such that they do not spoil. Once the yearly harvest of sugarbeets has been processed, the boilers at such facilities cease to operate until the next harvest is received. The limited use nature of the boilers further supports either adding them to the current seasonal subcategory or creating a separate subcategory, because the overall

emissions impact of such boilers is low. Over eighty percent of the boilers run for eight months or less a year. It is appropriate for the agency to take these lower levels of operation for agricultural boilers into account and to either add them to the existing seasonal use subcategory or create a new subcategory to reflect their unique characteristics.

Response: This comment pertains to the area source boiler rulemaking. Provided the commenter has submitted this comment to the area source boiler rulemaking docket, the response to this comment will be provided there.

Commenter Name: James Johnson

Commenter Affiliation: United States Beet Sugar Association (USBSA)

Document Control Number: EPA-HQ-OAR-2002-0058-3508-A1

Comment Excerpt Number: 4

Comment: Management Practices

As these comments demonstrate, it is appropriate for EPA to either add boilers at sugarbeet processing facilities to the seasonal subcategory or create a separate area source subcategory for those boilers. Because of the agricultural-based locations and consequent lower emissions impacts of such boilers, as well as the challenging economic circumstances surrounding many such agriculture processing facilities, USBSA requests that EPA create a management practices standard for such sources. EPA has the discretion to create management practices standards under CAA section 112(d)(5) for area sources to reduce HAP emissions. As currently written, the reconsidered rule would require that sugarbeet processing facilities undergo significant physical modification in order to comply with the emission limits. These facilities would have a very difficult time meeting the standards especially considering that appropriate technology may not be readily available, is extremely costly, and has unknown reliability, and there is limited time for implementation. Therefore, there is a strong rationale for adopting management practices for a seasonal subcategory of boilers located away from concentrated urban centers. Management practices would provide for environmental protection while avoiding burdensome regulations that negatively impact the United States' agricultural industry and do not provide meaningful environmental and public health benefits. USBSA suggests that EPA adopt management practices for agriculturally-based seasonal boilers that include actions such as employing good combustion practices on a boiler-specific basis, creating and carrying out operations and maintenance plans for individual boilers, periodic tuneups of the boilers, and a periodic maintenance inspection. There also may be other suitable management practices, and USBSA looks forward to working with the agency to determine appropriate work practices for agricultural, seasonal boilers.

Response: This comment pertains to the area source boiler rulemaking. Provided the commenter has submitted this comment to the area source boiler rulemaking docket, the response to this comment will be provided there.

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 61

Comment: 45Th purpose of this submission is to provide EPA with some information relevant to the boiler and waste rules applicability to biomass burners, using a fairly comprehensive database of recently issued air permits to characterize current trends in the industry. We wish to demonstrate to EPA that the boiler and waste rules as currently conceived are opening the door to far greater pollution, and more toxic pollution, from the biomass energy sector than is necessary, given the technologies available for emissions control and the reasonable presumption that the public should have that "clean" biomass fuel burned as renewable energy does not consist of toxic waste. We submit these comments in support of legal comments from Earthjustice, and also on our own behalf. As part of our own submission, we are attaching comments we submitted on the "beneficial use determination" for a facility in Massachusetts, Palmer Renewable Energy, that proposed to burn construction and demolition debris.

We compiled a database of permits for biomass facilities issued in the last four years. All are power producers.

There are 67 new and re-permitted facilities in the database.

Of these 21 are existing facilities that are expanding their existing biomass capacity or adding a biomass boiler; 46 are new facilities. Some of the new facilities have now been withdrawn but were included in the permit database as examples of contemporary permitting practices.

Not every permit or application specifies the type of boiler. Of the ones that are specified, 31 are fluidized bed boilers; 26 are stokers. There are no examples of some of EPA's categories, e.g. "dutch ovens" or "biomass fuel cells".

Major/minor status of facilities in the database

For the purposes of BACT determination/criteria pollutants, regarding major/minor status:

- 1) 3 are not specified
- 2) 22 are major sources.
- 3) 42 are minor sources. Of these, 29 are synthetic minors.

For the purposes of MACT determination/HAPs,

- 1) 7 facilities do not specify whether they are major or area sources (most of these are modifications to add a biomass boiler or expand capacity at an existing facility, and permits do not always specify whether these facilities are currently major sources for MACT).
- 2) 9 facilities are major sources
- 3) 44 facilities are "area" sources.

Synthetic area sources for HAPs – our definition

Of the 44 area source facilities, 32 are what we characterize as "synthetic" minor sources. By this we mean:

- 1) the permit either specifies little information about actual HAPs emission rates, but specifies that the facility will emit "less than" 25 tons of all HAPs and less than 10 tons of any HAP.
- 2) Or, the permit/application does add up emissions of HAPs with specific emission rates, and miraculously comes in just under 25 tons (it is common for HAPs to sum to 24.9 tons).
- 3) Or, the permit/application selectively uses a mix of AP-42 emission factors, NCASI emission factors, and other industry-provided emission factors to estimate HAPs emission rates, with a sum that comes in just under 25/10 tons. In some cases, NCASI and other industry emission rates are used that are orders of magnitude lower than AP-42 rates. Often the AP-42 rates that are supplanted with industry data are graded "A" for data reliability. Very few if any permits/applications provide justification for using something other than the AP-42 rates.

Response: This comment pertains to the area source boiler rulemaking. Provided the commenter has submitted this comment to the area source boiler rulemaking docket, the response to this comment will be provided there.

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 62

Comment: *Area source biomass facilities are large*

The new facilities now being permitted around the country are mostly large, standalone electricity-producing plants. While the "area" source rule would appear to be intended to govern relatively small facilities, the facilities governed by the rule are actually quite large and overlap considerably in size with facilities designated as major sources. [See submittal for the boiler capacity (mmbtu/hr) for "area" and "major" sources in our database.]

Response: This comment pertains to the area source boiler rulemaking. Provided the commenter has submitted this comment to the area source boiler rulemaking docket, the response to this comment will be provided there.

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 63

Comment: *Facilities burning construction and demolition waste (C&D)*

There are at least 16 facilities in the database that plan to burn construction and demolition waste. Some of these specify that only "clean" C&D can be burned. In our review of permits and applications, we found only one fuel sorting study. We analyzed this study and found it to be utterly deficient in terms of the statistical approach used to characterize contamination in the fuel stream (we have attached this analysis). Most if not all facilities with permits allowing burning of C&D do not specify a fuel testing plan; the permits generally say "no burning of treated wood" with no verification provisions.

Of the 16 facilities that plan to burn C&D 11 are minor sources that will not go through BACT; 7 are synthetic minors for BACT (by "synthetic minor", we mean facilities with a potential to emit that is greater than 250 tons of a criteria pollutant, but the permit caps emissions at 250 tons).

10 are area sources for HAPs, and thus will be regulated under the area source rule. Of these, 9 are "synthetic" area sources (see above for our definition of a synthetic area source for HAPs).

Response: This comment pertains to the area source boiler rulemaking. Provided the commenter has submitted this comment to the area source boiler rulemaking docket, the response to this comment will be provided there.

Commenter Name: James Pew

Commenter Affiliation: Earthjustice, Clean Air Council, Partnership for Policy Integrity

Document Control Number: EPA-HQ-OAR-2002-0058-3511-A1

Comment Excerpt Number: 64

Comment: *The significance of the waste definition in the context of the area source rule*

We provide comment on the use of non-hazardous secondary materials such as C&D below. Here we note that the area source rule and the definition of biomass (which will now encompass a great deal of material that would ordinarily be considered "waste") are interlinked in an important way. As EPA loosens restrictions on what can be defined as "biomass" instead of "waste", there will be an increasing number of large facilities burning potentially contaminated material, but since many are considered "area" sources, they will only be regulated for PM, not other pollutants that are regulated under the major source MACT rule.

Response: This comment pertains to the area source boiler rulemaking. Provided the commenter has submitted this comment to the area source boiler rulemaking docket, the response to this comment will be provided there.

Commenter Name: Alicia Meads

Commenter Affiliation: National Association of Manufacturers (NAM)

Document Control Number: EPA-HQ-OAR-2002-0058-3515-A1

Comment Excerpt Number: 15

Comment: The EPA is proposing to amend 40 CFR 63.11196 to specify that all existing boilers subject to the tune-up requirement would have two years (by March 21, 2013) in which to demonstrate initial compliance, instead of one year to demonstrate initial compliance. The EPA requested comment on whether the initial compliance period for the tune-up requirement should be extended to three years. 76 Fed. Reg. 80,535.

For many of the same reasons discussed above, the NAM recommends that this compliance period should be extended to three years. *See* 76 Fed. Reg. 15579, Table 4 (identifying 183,000 existing area source boilers). Combining a potential shortage of environmental engineers with the long range planning required for testing and work at facilities, it will be difficult to schedule and complete the testing needed to comply with the tune-up requirements in time to meet a two year deadline, particularly for facilities with multiple boilers.

Response: This comment pertains to the area source boiler rulemaking. Provided the commenter has submitted this comment to the area source boiler rulemaking docket, the response to this comment will be provided there.

Commenter Name: Mary Sullivan Douglas

Commenter Affiliation: National Association of Clean Air Agencies (NACAA)

Document Control Number: EPA-HQ-OAR-2002-0058-3525-A1

Comment Excerpt Number: 45

Comment: EPA has also requested public comment on whether the compliance date for boiler tuneups for area sources should be extended to March 2013, as EPA is currently proposing, or if the compliance date should be extended to March 2014. To be consistent with the initial compliance date for boiler tune-ups at major sources, EPA should extended the compliance date for area sources to March 2014. Although the tune-up requirements do not appear overly burdensome, affected sources will still need sufficient time to determine what needs to be included in the tuneup protocol, when to schedule the initial tune-up, and to develop the reporting protocol that needs to be submitted to EPA or to the delegated state or local agency. Further, there appears to be no reason why the smaller area sources should not have the full three years to comply that is currently afforded to major sources. Extending the compliance date for tune-ups would also allow extra time for states to identify and provide outreach and compliance assistance to area source facilities. This assistance is very important, because many of these sources have had little prior experience in understanding and complying with complex air regulations. EPA is not providing states additional funding to implement these new standards. Having sufficient time before the compliance deadline to assistance affected area sources will help ease the implementation burden for states and will almost certainly minimize violations after the compliance date.

Response: This comment pertains to the area source boiler rulemaking. Provided the commenter has submitted this comment to the area source boiler rulemaking docket, the response to this comment will be provided there.

Commenter Name: Bart Sponsellar

Commenter Affiliation: Wisconsin Department of Natural Resources

Document Control Number: EPA-HQ-OAR-2002-0058-3527-A2

Comment Excerpt Number: 29

Comment: The finalized MACT rule for area sources does not distinguish between limited use boilers separate from boilers used in regular service. EPA is proposing under the reconsideration to create a separate subcategory for "seasonally" operated boilers which do not run for at least 7 months out of the year. This requirement is based on operation of agricultural oriented processing of crops such as in the sugar cane industry. These boilers under the finalized MACT are subject to tune-ups every two years. EPA is now proposing that seasonal boilers be subject to tune-ups every five years.

The Department supports aligning the frequency of tune-ups across sources to be proportional to their operation. We believe EPA's finding that sources operating less frequently are subject to a more restrictive requirements and more costs than regularly operated sources on the same tune-

up schedule. However, we believe the proposed definition of seasonally operated boilers does not adequately address the different sources which are not in regular season through the year. One example, especially in northern climates, is space heating boilers (non-residential) which operate less than half of the year. Other types of applications certainly exist throughout the different commercial and industrial facilities.

The Department suggests that EPA create a "limited use" subcategory similar to the major source boiler rule. This subcategory can define limited use units based on total operating hours or percent operation during the year. The definition, if necessary, could further require that operation must occur in consecutive months and with more than four consecutive months of non-operation.

Instead of establishing a separate seasonal or limited use subcategory, EPA may want to consider allowing an alternative schedule for all tune-ups under the Area source rule. Under this schedule, the rule can simply require tune-ups based on the total of 12, 24, or 60 operating months to reflect the annual, biennial, and five year tune-up requirements affecting different sources. The Department acknowledges that the number of months allowed may need to be adjusted to reflect the average operation time of sources subject to the primary requirements.

A separate option we believe EPA should consider is allowing sources which install and operate a CO/O₂ CMS trim system to perform tune-ups once every four years. This form of combustion trimming basically tunes the boiler on a continually basis and is superior to periodic tune-ups. Therefore a "tuneup" is only required on a schedule necessary to inspect mechanical systems and the boiler burners. Under this approach sources would not have to track seasonal or limited operating in qualifying for an alternative schedule.

Response: This comment pertains to the area source boiler rulemaking. Provided the commenter has submitted this comment to the area source boiler rulemaking docket, the response to this comment will be provided there.

Commenter Name: Bart Sponsellar

Commenter Affiliation: Wisconsin Department of Natural Resources

Document Control Number: EPA-HQ-OAR-2002-0058-3527-A2

Comment Excerpt Number: 30

Comment: EPA is proposing to create a subcategory of "Temporary" boilers which are exempt from boiler MACT requirements. EPA proposed a definition where a boiler does not qualify as temporary if it is onsite for more than 12 months.

The Department supports EPA's approach to exempting boilers used in such circumstances. However, there may be cases where construction schedules extend beyond a year. For example, if a facility is replacing multiple boilers. The Department feels that an allowance needs to be made for non-permanent boilers which may be on site longer than 12 months. EPA stated an expectation that temporary boilers are typically less than 10 mmBtu/hr and primarily oil or gas fired. The primary MACT or GACT requirement for these boilers would be to perform a tune-up. A simple approach that addresses both time constraints and the tune-up requirement is to allow that any temporary boiler, remaining on site longer than 12 months, is exempt from MACT requirements if the boiler is operated using an oxygen trim system. The Department feels that

this approach ensures that the boiler has the same good standard operating equipment in place that is reasonably expected for any gas or oil fired boiler. This exemption also addresses that the same boiler will be operated again much like a limited use or regularly operated boiler – just on another site.

Response: This comment pertains to the area source boiler rulemaking. Provided the commenter has submitted this comment to the area source boiler rulemaking docket, the response to this comment will be provided there.

Commenter Name: Bart Sponsellar

Commenter Affiliation: Wisconsin Department of Natural Resources

Document Control Number: EPA-HQ-OAR-2002-0058-3527-A2

Comment Excerpt Number: 31

Comment: The finalized MACT rule required many sources to perform tune-ups within a year of rule promulgation. In the reconsideration, EPA is proposing to extend the requirement to within two years of rule promulgation. The Department supports extending the compliance schedule for the initial tune-up requirement. However, the Department requests that EPA consider extending the schedule to within three years of rule promulgation. At a minimum EPA should consider extending the compliance deadline to three years for any source installing CO/O₂ CMS trim systems to continuously tune the boiler system.

The Department acknowledges that the Clean Air Act requires implementation of MACT requirements as expeditiously as practicable. However, we believe EPA needs to consider that the major source ICI and EGU rules are being implemented on the same or similar time frame as the area source rule. These rules will require the same resources and vendors for tune-ups and energy assessments as needed by sources subject to the area rule. Another factor is that many sources will be addressing multiple emission requirements ranging from multiple pollutant emission limitations to a minimum of a tune-up and energy assessment. Further, the tune-up requirements currently have no lower threshold in place for the size of solid fuel fired unit affected at an area source. Clearly, the area source will apply to sources which are being regulated to this degree for the first time. In fact, we firmly believe that significant time will be required to even identify all of the affected sources. We believe that without a clear assessment of the entire affected pool of sources or the interaction between the multiple MACT rules that EPA needs to be prudent in establishing compliance deadlines. Lastly, EPA needs to consider that portions of the rule are still under reconsideration, including the schedule for tune-up requirements. EPA had identified such areas would be under reconsideration and cannot anticipate that significant sources have moved forward in the compliance. For all of these reasons the Department encourages EPA to utilize the full 3 years allowed under the Clean Air Act with a compliance date of March 21, 2014.

The Department requests for EPA to consider an extended compliance schedule for sources installing a CO/O₂ trim system. This is an alternative compliance option the Department is proposing in lieu of the current frequency of tune-ups (refer to discussion of CO monitoring). Basically, sources can have the alternative to use a CO/O₂ CMS trim system to operate continuously at good combustion conditions; i.e. continuously tuning the boiler. We believe this approach is more beneficial to both the source and ensures continuous emissions improvement.

At a minimum, we request that sources installing such equipment be allowed the full 3 year compliance timeframe.

The Department feels that EPA should consider extending the compliance date for energy assessments under the rule to 4 years after promulgation. The energy assessment requirement is basically a "secondary" requirement. For some utilities results of the energy assessment may provide enough benefit to aid in meeting requirements under the output based emission limitations. We believe facilities will self-identify this potential and move ahead with energy assessments and improvements in the 3 year compliance time-frame. EPA followed this concept in not requiring implementation of assessment results. However, larger sources will likely have to focus first on implementing primary emission controls or optimize the boiler combustion to ensure meeting the emission limitations. For these sources the energy assessment is a secondary measure with results implemented only if cost-effective. We believe that such facilities should be able to pursue the energy assessment on a time-frame which is most beneficial to them in both meeting rule requirements and applying resources. Once again EPA should also consider here that available vendors and resources will be needed in meeting both the area and major source rules. These resources should be most readily available to sources for which the assessment will help meet emission limitations. For these reasons we believe that the compliance date for energy assessments should be four years from rule promulgation, especially since implementation of energy assessment results is voluntary.

Response: This comment pertains to the area source boiler rulemaking. Provided the commenter has submitted this comment to the area source boiler rulemaking docket, the response to this comment will be provided there.

Commenter Name: Bart Sponsellar

Commenter Affiliation: Wisconsin Department of Natural Resources

Document Control Number: EPA-HQ-OAR-2002-0058-3527-A2

Comment Excerpt Number: 32

Comment: *1. CO CEMs monitoring:* Under the finalized rule sources are required to demonstrate compliance with CO emission limitations through annual stack testing. EPA is proposing in the reconsideration that sources, as an alternative, can demonstrate compliance with CO emission limitations using a certified CO CEMs. This is because some sources already have a CO CEMs monitoring system in place.

The Department supports allowing use of a CO CEMs for demonstrating compliance with applicable CO emissions limitations. However, the Department believes that sources should also be allowed to perform parametric monitoring and continuous tune combustion using a CO/O₂ continuous monitoring and trim system (CMS). This CO/O₂ CMS trim system option can provide for stack testing every two years instead of annually.

The Department believes that EPA should consider that many sources already have in place and operate CO analyzer systems in order to operate their boilers at good combustion conditions. This type of system is usually operated along with O₂ monitoring to create a CO/O₂ trim system for the boiler. A number of sources in Wisconsin's ozone non-attainment areas, including coal stokers, glass furnaces, and lime kilns, are currently required to operate CO/O₂ trim systems

under a combustion optimization requirement. We believe that EPA should consider that these systems can be correlated to absolute CO values during periodic stack testing and provide a better continuous demonstration of compliance versus monitoring oxygen alone. EPA already acknowledges that O2 trim systems are superior to parametric monitoring of O2 alone. From this perspective using a CO continuous monitoring system (non-CEMs) is a higher level yet of parametric monitoring and provides better assurance of actual CO emission levels. In addition, based on our experience, CO is a more sensitive parameter to use than O2 in tuning a source for good combustion (see discussion in major source comments under "oxygen monitoring"). For these reasons, when a source is operating a CO/O2 CMS trim system we believe that stack testing on an annual basis is not necessary. The CO CMS will identify relative changes in CO while the overall system ensures better continuous combustion and greater emission reductions than achieved by O2 monitoring. Therefore, we believe that stack testing should only be required on a biennial basis for sources utilizing a CO/O2 CMS trim system.

EPA is proposing a similar approach in allowing a PM CMS in place of a PM CEMs requirement under the major source MACT rule. This shows that a non-certified monitoring system can be specified and expected to yield quality data and can be a less costly option than a CEMs system but still provide better compliance and emission results than a stack test approach.

2. Oxygen monitoring: The finalized rule requires sources to determine an O2 concentration level during stack testing which is consistent with meeting the CO emission limitation. The source is then required to continuously monitoring O2 concentrations according to part 60 requirements as parametric monitoring for compliance. In the reconsideration, EPA is proposing that instead of requiring O2 monitoring that a source can perform parametric monitoring using an oxygen analyzer continuous monitoring and combustion trim system.

The Department supports the use of an oxygen CMS trim system instead of CEMS oxygen monitoring. We believe this approach provides continuous tuning of combustion which will result in overall lower emissions levels as compared to monitoring to comply with a single O2 concentration value. We also recommend that EPA allow for use of a CO/O2 CMS trim system with biennial stack testing as previously discussed.

Response: This comment pertains to the area source boiler rulemaking. Provided the commenter has submitted this comment to the area source boiler rulemaking docket, the response to this comment will be provided there.

Commenter Name: Bart Sponsellar

Commenter Affiliation: Wisconsin Department of Natural Resources

Document Control Number: EPA-HQ-OAR-2002-0058-3527-A2

Comment Excerpt Number: 33

Comment: The EPA in the finalized rule determined that 30-day averaging of parametric monitoring parameters is appropriate to account for variability. EPA is requesting comment on this finding.

The Department supports EPA's conclusion that 30-day averaging of parametric parameters is appropriate. The Department requests that EPA clarify and ensure the rule language allows a source to use instantaneous or un-averaged value in showing compliance with the set parameter

value. We are aware that equipment such as excess oxygen monitors is currently in place to monitor and record the instantaneous value. Instead of replacing this equipment or creating additional work to compile the data some sources simply plan to demonstrate that excess oxygen always remains below the targeted value. This option should be clearly allowed under the current rule language as this approach is more restrictive than using the averaged parametric values.

Response: This comment pertains to the area source boiler rulemaking. Provided the commenter has submitted this comment to the area source boiler rulemaking docket, the response to this comment will be provided there.

Commenter Name: Bart Sponsellar

Commenter Affiliation: Wisconsin Department of Natural Resources

Document Control Number: EPA-HQ-OAR-2002-0058-3527-A2

Comment Excerpt Number: 34

Comment: Tune-up Work Practices

1. Oil fired boilers < 10 mmBtu/hr: The finalized rule provides that oil fired boilers < 10 mmbtu/hr are subject to a biennial tune-up requirement. In the reconsideration, EPA is proposing that oil-fired boilers should be subject to tune-ups every five years with an initial compliance date of March 21, 2014.

The Department supports using the full available time allowed under the Clean Air Act in setting the initial compliance date of March 21, 2014 (refer to comments on initial compliance schedule). EPA's rationale that large numbers of small sources at a source may be affected resulting in logistical issues is correct.

We believe that EPA's rationale is not limited to just oil-fired boilers and for just area sources. The same complexity exists for all small boilers < 10 mmBtu/hr. Sources may have a mix of small boilers affected under the area rule: biomass, coal, and oil. We are particularly concerned with added complexity for biomass fired boilers where sources may not be currently regulated therefore adding a different logistical issue. The complexity of logistics is not limited to only small boilers. Traditional industrial sources with small boilers will also likely have large boilers subject to tuning and emission limits. It is difficult to distinguish logistic issues and complexity between sources with multiple small boilers and sources with a mix of small and large boilers. Using EPA's rationale, the tune-up compliance date for all boilers and process heaters regardless of size should be no sooner than March 21, 2014.

The Department believes that this same issue applies to boilers under the Major Source Rule and should be appropriately considered by EPA.

2. Conducting Initial Tune-ups at New Sources: EPA is proposing under the reconsideration that new sources will not be subject to an initial tune-up. Their reasoning is that a tune-up is inherent to starting a new source.

The Department agrees that a tune-up and full optimization of combustion will occur during startup operations of a boiler. In fact, this process is likely to take some time during shakedown of the unit operations. Clearly, optimization and tuning of the combustion may be conducted by

the boiler vendor or a different contractor than may be normally employed for a regular tune-up. In many respects this startup process may involve personnel with more complete knowledge of the system and the intended operation points of the boiler. For this reason, the Department believes it is still important for results of the tuning process be recorded. This initial start-up information provides the basis and bench-marks for measuring the effectiveness of ensuring tune-ups. Comparisons to this base information will also identify whether there are significant changes in the system and identify if other actions are needed to maintain good combustion. In fact, we would expect that a tune-up would occur any time there is a major change in equipment affecting combustion.

Therefore we recommend that EPA require an initial recording of tuning set points be recorded no later than 60 days of when full and continuous operational levels are demonstrated.

3. Clarification of Tune-up monitoring: Currently, tune-ups require measurement of oxygen and carbon monoxide concentrations in the flue gas. In discussions with potentially affected sources and equipment providers it is apparent that there is confusion whether combustion analyzer measurements are sufficient or if oxygen measurements need to be taken following 40 CFR part 60 methods for stack testing. We request that EPA clearly specify the acceptable approaches and methods in quantifying combustion gas concentrations for purposes of a

3. Small Biomass boilers and process heaters: With respect to biomass boilers < 10 mmBtu/hr the Department requests that EPA clarify tune-up requirements. The rule currently suggests that tuning steps or measure be followed as applicable or specified by the manufacturer. However, the rule also indicates that if steps are not specified for that unit that measures are to be followed as specified by manufacturers of similar units. This approach will result in confusion and potential differences in applying the tune-up requirements. Specifically, as biomass boilers become smaller it is more likely that there will be less ability to adjust combustion air accordingly or even to expect that same combustion settings should remain the same between firings. This latter point becomes especially apparent for boilers which are manually fired or operated on a single load basis. In addition, for smaller boilers it is more likely that fuels will vary more in type and quality. For these reasons we believe that at some level small boilers simply may not be tunable in the sense the rule requires – establishing a single tuned set point. As units become smaller it may even be technically challenging to obtain correct combustion gas readings or correctly adjust combustion gases. Therefore we ask EPA to provide rule language which clarifies that a source does not have to perform combustion gas measurements or flue gas adjustments if technically infeasible. We suggest that for such sources the rule specify best practices of firing clean, un-wetted fuels with visual inspection for good combustion characteristics for boilers < 5 mmBtu/hr or for boilers which are manually loaded.

Preferred Approach – The Department agrees with EPA that all boilers should operate following good combustion practices in order to minimize toxic emissions. However, the Department does not feel that biomass boilers smaller than 10 mmBtu/hr have been sufficiently characterized in order to proscribe technically sound requirements. This is particularly true with no lower threshold for applicability. For oil and natural gas fuels, the boiler components and fueling methods are fairly similar regardless of size. But for smaller biomass boilers we believe, as previously discussed, that there will actually be more variability in combustion configurations, the ability to adjust combustion air, and in fuel quality as boilers decrease in size. EPA needs to also consider that certain boilers are configured and intended to operate under

smoldering conditions most of the time until heat is called for from the unit. Finally without a clear characterization of small biomass units, we feel that EPA cannot even adequately determine what sources are likely to be considered an area source.

For this reason we request that EPA define a lower threshold for biomass boiler applicability under the area source rule at this time. We also believe the same threshold should be applied in the major source rule as well. The Department suggests that this threshold, at a minimum, should be no lower than 5 mmBtu/hr. At this time we do not have a technical basis for determining an appropriate lower applicability threshold. This speaks to our lack of information for biomass boilers at this time. The suggestion is solely based to match the threshold at which tune-ups for oil fired boilers go from a two to five year requirement.

Response: This comment pertains to the area source boiler rulemaking. Provided the commenter has submitted this comment to the area source boiler rulemaking docket, the response to this comment will be provided there.

Commenter Name: Bart Sponsellar

Commenter Affiliation: Wisconsin Department of Natural Resources

Document Control Number: EPA-HQ-OAR-2002-0058-3527-A2

Comment Excerpt Number: 35

Comment: GACT emission limits for Biomass and Oil-Fired Boilers

The Department supports that all biomass boilers and oil-fired boilers smaller than 10 mmbtu/hr should be subject to limitations no more stringent than GACT instead of a MACT based requirement. EPA has appropriately determined that these boilers are not needed under MACT to address 90% of the urban toxic emissions. In addition, smaller biomass fired sources vary greatly in combustion configuration where one MACT requirement may not be technically appropriate. Finally, based on the definition of "biomass" under the non-hazardous secondary materials rule, these sources will have minimal emissions compared to the source categories regulated under MACT. The Department supports a good work practices under GACT for biomass and oil-fired sources.

Response: This comment pertains to the area source boiler rulemaking. Provided the commenter has submitted this comment to the area source boiler rulemaking docket, the response to this comment will be provided there.

Commenter Name: Bart Sponsellar

Commenter Affiliation: Wisconsin Department of Natural Resources

Document Control Number: EPA-HQ-OAR-2002-0058-3527-A2

Comment Excerpt Number: 36

Comment: Title V Permitting Requirements

The Department strongly supports EPA's proposal to exempt area source boilers, including synthetic area sources, from Title V permitting requirements. The Department, if necessary, can incorporate MACT requirements into current existing minor source state permits. This approach

also leaves open the opportunity to establish general operating permits for source categories where applicable.

Response: This comment pertains to the area source boiler rulemaking. Provided the commenter has submitted this comment to the area source boiler rulemaking docket, the response to this comment will be provided there.

Commenter Name: Bart Sponsellar

Commenter Affiliation: Wisconsin Department of Natural Resources

Document Control Number: EPA-HQ-OAR-2002-0058-3527-A2

Comment Excerpt Number: 37

Comment: Consolidated Carbon Monoxide, Tune-up, and Stack testing Requirements

Many of the Department's comments are formulated from a common basis. The Department believes that there is significant opportunity, in context of the issues open for comment, to achieve the same or better environmental results and reduce compliance cost by allowing CMS parametric monitoring for PM, Hg and CO and O₂ monitoring for good combustion. One basic benefit in pursuing an alternative compliance demonstration is better parametric monitoring and stable combustion conditions which will allow for stack testing on a biennial schedule. This is very important for sources in reducing compliance cost and aligning stack testing with current Wisconsin stack testing requirements.

Although not providing absolute certified values, a CMS system which directly monitors the regulated pollutant ensures better overall environmental results as compared to an annual stack test. EPA has basically followed this premise in proposing the use PM CEMs, CO CEMs and Hg CEMs as an alternative in demonstrating compliance. EPA has also shown with the proposal of a PM CMS and oxygen trim systems for parametric monitoring that they believe quality monitoring can be standardized without requiring full CEMs certification. In this approach CMS data is correlated to the periodic stack test for each source and ensures ongoing compliance. The CO CMS is also correlated to good combustion over different loads with the source required to continuously trim the system to good combustion when operating. Because of the obvious higher value of operating direct pollutant CMS systems the Department suggest that biennial stack testing be allowed in place of annual stack when operating such a system. The Department also believes that monitoring of other operating parameters is not required when directly monitoring the pollutant of interest with a CMS.

The Department also believes that stack testing can be allowed on a biennial schedule for sources with emission limitations the sources are operating a positive control system for the pollutant in question. Specific cases we have identified where we believe biennial stack testing applies under positive control systems are as follows. The Department proposes that a CO CMS and good combustion trim system is positive control in reducing all organic toxics including dioxin and furans. EPA is proposing that particulate is a combustion based pollutant. Under this approach we believe that a source operating with good combustion (CO CMS) and ESP or fabric filter systems is a positive control system for both PM and non-mercury metals. In this case the source should be able to monitor the necessary parameters and stack test every two years for PM or metals. The Department also believes this approach constitutes an option equal to a PM CMS

compliance demonstration. The Department believes that a similar approach and biennial stack testing schedule can be taken for mercury controlled by activated carbon injection and for hydrogen chlorides controlled by either dry or wet scrubbing. To simplify this option, EPA can allow a source to demonstrate a correlation between the pollutant of interest and the positive control measure. If necessary this correlation can be approved by the delegated authority.

The Department also suggests EPA consider that a CO CMS system with good combustion trim requirements basically constitutes continuous tuning of the source. Along with biennial stack testing the CO CMS trim system is checked every two years. Under this monitoring approach, the Department believes that tune-ups are only necessary every four years. This schedule coincides with the time frame EPA suggests for inspecting burners and other boiler system equipment.

Response: This comment pertains to the area source boiler rulemaking. Provided the commenter has submitted this comment to the area source boiler rulemaking docket, the response to this comment will be provided there.

Commenter Name: Bart Sponsellar

Commenter Affiliation: Wisconsin Department of Natural Resources

Document Control Number: EPA-HQ-OAR-2002-0058-3527-A2

Comment Excerpt Number: 38

Comment: For source categories that do not have emission limitations, such as oil and gas boilers or boilers smaller than 10 mmBtu/hr, the MACT rule requires that tune-ups be performed every two years. These sources should have the alternative to install and operate a CO/O₂ CMS trim system with tune-ups conducted on a four year schedule. This provides the same alternative as proposed for the larger sources subject to emission limitations.

Lastly, this proposed schedule for CO, PM, and tune-ups is premised on the CO/O₂ trim system and a two year stack test schedule. A three or four year tune-up and stack test schedule could be considered for sources which implement a neural network system in operating the boiler system. This approach is adopted under in the finalized EGU MACT rule. The default requirement is for EGU boilers to undergo tune-ups every 36 months or 3 years. However the rule allows EGU sources with a neural network system in place to perform tune-ups on a four year cycle. To put a neural network system in place a source is typically tested intensively with computer fluidized modeling performed to determine optimum conditions for operating the boiler. The Department feels that a source which is optimized and operated to this level can be placed on a three or four year stack test schedule at a minimum for PM and CO emissions and for tune-ups.

Response: This comment pertains to the area source boiler rulemaking. Provided the commenter has submitted this comment to the area source boiler rulemaking docket, the response to this comment will be provided there.

Commenter Name: Robert D. Bessette

Commenter Affiliation: Council of Industrial Boiler Owners (CIBO)

Document Control Number: EPA-HQ-OAR-2002-0058-3534-A1

Comment Excerpt Number: 16

Comment: In addition, EPA is proposing to create a new subcategory for seasonally operated boilers. For these seasonally operated boilers, EPA is proposing to require a tune-up every five years (following the initial tune-up). Seasonally operated boilers would be defined as follows:

"Seasonal boiler means a boiler that undergoes a shutdown for a period of at least 7 consecutive months (or 210 consecutive days) due to seasonal market conditions. This definition only applies to boilers that would otherwise be included in the biomass subcategory or the oil subcategory."

We support the addition of a seasonal boiler subcategory. These boilers are used in seasonal agricultural operations or for comfort heat and typically operate only about 100 days per year, so the number of hours actually operated over a 5-year period is much less than a boiler in normal operation. Therefore, a 5-year tune-up frequency for these units is appropriate and is comparable to the tune-up frequency required for units that operate continuously.

However, this subcategory should also cover units that only operate during short periods of high electricity demand in the summer and for semi-annual capacity testing requirements. Because of the semi-annual testing required by the electric utility, the units will not meet the proposed criterion of being completely shut down for 7 consecutive months, but would otherwise be considered seasonal units and their limited operation is consistent with EPA's intent when developing this subcategory. Therefore, EPA should revise the definition of seasonal boiler to allow intermittent operational testing (e.g., up to 15 days) during the 7 month period. This would allow biomass or oil units at area sources that have availability requirements to ensure that the unit is available on short notice.

Response: This comment pertains to the area source boiler rulemaking. Provided the commenter has submitted this comment to the area source boiler rulemaking docket, the response to this comment will be provided there.

Commenter Name: John M. Cullen

Commenter Affiliation: Masco Corporation

Document Control Number: EPA-HQ-OAR-2002-0058-3661-A2

Comment Excerpt Number: 2

Comment: Masco supports EPA's decision to regulate biomass boilers based on "generally available control technologies or management practices" ("GACT"). EPA's June 4, 2010 proposed rule would have imposed standards for biomass-fueled area source boilers based on "maximum achievable control technology" ("MACT"). EPA has invited comment on the final area source standards based on GACT instead of MACT. The use of GACT is authorized in this case under Clean Air Act §112(d)(5). Moreover, as EPA acknowledges, only coal fired area source boilers are needed to account for the 90 percent requirement set forth in Clean Air Act §112(c)(6) for polycyclic organic matter ("POM ") and mercury (76 Fed. Reg. 80537). Accordingly, it is not reasonable or necessary to regulate biomass boilers based on MACT.

Response: This comment pertains to the area source boiler rulemaking. Provided the commenter has submitted this comment to the area source boiler rulemaking docket, the response to this comment will be provided there.

Commenter Name: John M. Cullen
Commenter Affiliation: Masco Corporation
Document Control Number: EPA-HQ-OAR-2002-0058-3661-A2
Comment Excerpt Number: 6

Comment: Masco supports EPA's proposal to exempt area sources from any requirement to obtain a Title V permit based solely on their regulation as an area source under the Boiler MACT rules. Masco agrees with EPA's rationale for this proposal, as set forth at 75 Fed. Reg. 31910-31913 (June 4, 2010). As the Agency found, "the monitoring, record keeping and reporting requirements of the proposed NESHAP are sufficient to assure compliance" with the rule and "title V would not significantly improve those compliance requirements." 75 Fed. Reg. 31911. Moreover, EPA explained that Title V permitting requirements would impose significant and burdensome costs averaging \$65,700 per source for a 5-year permit period, with little or no additional compliance assurance.

Response: This comment pertains to the area source boiler rulemaking. Provided the commenter has submitted this comment to the area source boiler rulemaking docket, the response to this comment will be provided there.

Commenter Name: Jennifer Youngblood
Commenter Affiliation: National Tribal Air Association
Document Control Number: EPA-HQ-OAR-2002-0058-3667-A2
Comment Excerpt Number: 26

Comment: The Association appreciates EPA's protection of health and environment of communities by controlling the emission of hazardous air pollutants from area sources. However, there is some concern that in Section VII(F) of the Federal Register notice it states "This proposed rule does not have Tribal implications as specified in Executive Order 13175". This language causes concern that even though the reconsideration may have potential impacts to Tribal Communities, it appears that that is not an issue being addressed. The Association wished to thank EPA's Office of Air Quality Planning and Standards for the outreach conducted to educate Tribes on this reconsideration.

Since many Tribes are now using biomass boilers and the U.S. Department of Energy is promoting Biomass energy resources in their Tribal Energy Program as an alternative energy source, the proposed Rule appears to place compliance schedules for the units on Tribal governments.² The Association also recognizes that language regarding residential boilers used in single family and multi-family residences is being included to indicate that these units should not be subject to subpart JJJJJ. Many of these units are used in Tribal housing and if regulated fully, may cause an undue fiscal cost to Tribal Housing Authorities, thus impacting Tribes. The Association is pleased that the Rule addresses this in a proposed amendment to 40 CFR 63.11195.

The Association would like to take this opportunity to provide EPA with our comments and recommendations regarding the need for EPA to clearly integrate Tribes in the implementation of the Rule and other EPA reconsiderations regarding the Rule. To assist EPA in gaining a better

understanding on our views regarding this reconsideration, the Association has bolded and italicized its recommendations below to distinguish them from our general comments.

Tribal-Related Issues about the Rule

EPA's policy is to work with Tribes on a government-to-government basis in implementing the NESHAP. This reconsideration contains provisions which clearly have the potential to impact Tribal Nations. These are the establishment of standards for biomass and oil-fired area source boilers based on generally available control technology, the proposal of a new subcategory for seasonally operated boilers and establishing GACT Emission Limits for biomass boilers. The Association is in agreement in two areas that may have Tribal implications. These areas are exemption for temporary boilers and adding residential boilers to the list of boilers not subject to subpart JJJJJ. This reconsideration of the Rule seeks to clarify language of the NESHP.

The Association seeks clarification on steps that alternative energy resources funders can include when working with Tribal governments who wish to move to biomass energy resources.

Standards for Area Source Boilers, GACT and Costs

To determine GACT, EPA looks at methods, practices and techniques that are commercially available and appropriate for use by the sources in the category. A consideration of the economic impacts on sources in the category and the technical capabilities of those operating and

maintaining the emissions control systems is another piece to this determination. Tribes may have limited resources to conduct increased maintenance on these units. The Association understands that in the reconsideration Federal Register notice, EPA states that *“these amendments will not increase the costs for the final rule but will result in a decrease in the burden on small facilities as a result of the reduction on the frequency of conduction tune-ups for seasonal boilers and small (equal or less than 5 MMBtu/hr) boilers.”* The definition included in the notice on page 89542 foot note 3, defines small entities under 13 CFR 121.201 to include small businesses, small organizations and small governmental jurisdiction. It may be implied that Tribes are included in this but a clarification of this definitional language should include how Tribes fall into this amendment language.

The Association recommends that EPA conduct more clear and concise outreach with Tribes to facilitate understanding of the maintenance schedule of biomass boilers and to work with other federal Agencies which fund Tribal energy programs. Further, the Association would like to see clarification of language as to the role of Tribes in relationship to the “small entity” definition in 13 CFR 121.201.

[Footnote 2: <http://apps1.eere.energy.gov/tribalenergy/>]

Response: This comment pertains to the area source boiler rulemaking. Provided the commenter has submitted this comment to the area source boiler rulemaking docket, the response to this comment will be provided there.

Commenter Name: Shawn Good

Commenter Affiliation: Pennsylvania Chamber of Business and Industry

Document Control Number: EPA-HQ-OAR-2002-0058-3671-A2

Comment Excerpt Number: 4

Comment: A number of our members have expressed support for the creation of the seasonally-operated boiler subcategory, which, like many of the changes, will reduce requirements on boilers that operate infrequently or otherwise are likely to be insubstantial sources of HAPs. However, EPA proposes that seasonal boilers would include boilers that undergo "a shutdown for a period of at least 7 consecutive months (or 210 consecutive days) due to seasonal market conditions." Seasonal changes affect differing parts of the US. The seven month shutdown period benefits only facilities in the southern part of the country. The definition should be based upon differing regional climate conditions to allow for northern seasonal variances or shortened to five month shutdown criteria.

Response: This comment pertains to the area source boiler rulemaking. Provided the commenter has submitted this comment to the area source boiler rulemaking docket, the response to this comment will be provided there.

Commenter Name: Shawn Good

Commenter Affiliation: Pennsylvania Chamber of Business and Industry

Document Control Number: EPA-HQ-OAR-2002-0058-3671-A2

Comment Excerpt Number: 8

Comment: The Pennsylvania Chamber supports EPA's proposal to extend by 365 days the compliance date of the initial tune-up for new and reconstructed sources. However, we urge EPA to harmonize this extension with the definition of new/reconstructed sources by resetting the proposal date for defining such sources from June 2010 to the re-proposal date of December 2011. This will allow more reasonable lead time for covered sources to factor changes reflecting those revisions into construction plans.

Response: This comment pertains to the area source boiler rulemaking. Provided the commenter has submitted this comment to the area source boiler rulemaking docket, the response to this comment will be provided there.

Commenter Name: Matthew Todd

Commenter Affiliation: American Petroleum Institute (API) and American Fuel and Petrochemical Manufacturers (AFPM)

Document Control Number: EPA-HQ-OAR-2002-0058-3677-A2

Comment Excerpt Number: 180

Comment: III. Area Source Proposal Comments

1. Many of our wording and clarification suggestions relative to the major source rule apply to the areas source rule as well and should be incorporated into that rule.

2. The temporary boiler exemption should be clarified.

Proposed §63.11195(h) exempts temporary boilers from the area source proposal. Temporary boiler is defined in proposed §63.11237 as follows.

Temporary boiler means any gaseous or liquid fuel boiler that is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A boiler is not a temporary boiler if any one of the following conditions exists:

- (1) The equipment is attached to a foundation.
- (2) The boiler or a replacement remains at a location for more than 12 consecutive months. Any temporary boiler that replaces a temporary boiler at a location and performs the same or similar function will be included in calculating the consecutive time period.
- (3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.
- (4) The equipment is moved from one location to another in an attempt to circumvent the residence time requirements of this definition.

Paragraph (2) of this definition excludes a boiler or a replacement that "remains at a location for more than 12 consecutive months." And further specifies that "Any temporary boiler that replaces a temporary boiler at a location and performs the same or similar function will be included in calculating the consecutive time period."

The second sentence language creates a problem because there is no time period associated with the replacement. It is not unusual for a temporary boiler to be used for short periods during turnarounds or other maintenance activities that recur several years apart. Under the proposal, these boilers would not be considered temporary, because each boiler replaces the previous one and performs the same function, even though there is a multi-year gap between the occurrences. We believe that replacements that occur after a gap of at least one year should not be considered consecutive for the purposes of this definition and the language of paragraph (2) should be revised to reflect that situation.

3. Only a design or Operations and Maintenance Plan requirement should apply to liquid fired boilers with a design heat duty of <10 MMBTU/hr.

Under this proposal, liquid-fired boilers of <5MMBTU.hr duty require tune-ups every five years. As discussed in Comment II.3.B, relative to gas and light liquid-fired BPH at major sources, even an every five year tune-up is not justified and we recommend a design practice or Operations and Maintenance Plan work practice instead.

Instead of the proposed five year tune-up, a design practice requiring the boiler to be designed to fire liquids or an Operations and Maintenance Plan work practice, such as incorporated into the Engine NESHAP should be required. Item 9 of Table 6 of part 63 subpart ZZZZ addresses the parallel situation for small and limited use engines. It requires that the owner/operator follow a work practice and demonstrate continuous compliance by "(i) operating and maintaining the stationary RICE according to the manufacturer's emission-related operation and maintenance instructions; or (ii) develop and follow your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions."

4. The residential boiler exemption should be extended to similar boilers providing comfort heat and hot water for similarly sized offices and other spaces. 1. On page 80616 of the major source proposal 54 , EPA states:

Residential Unit Exemption. During the initial phases of implementation of the area source boiler rule, stakeholders requested clarification from the EPA on the applicability of the area source rule to residential boilers, particularly those units at individual residences located at institutional facilities. The EPA's intent was not to cover such units, and during reconsideration, the EPA is amending the area source rule accordingly.

Since a residential boiler is defined as a boiler providing only comfort heat and/or hot water for up to four residential units, we believe a boiler providing comfort heat and/or hot water for an office, workroom, control room, or similar space of similar size⁵⁵ should also be exempted. Such small boilers, whether firing gas or liquid, have miniscule emissions and there is no environmental or health basis for imposing any requirements on such small emission sources.

5. Our comments in Section II.8 above on the major source proposal also apply to the malfunction and affirmative defense requirements in the area source proposal.

6. Comments on the Energy Assessment Requirements

A. The energy assessment requirement is not justified and should be deleted.

The proposal to impose a facility-wide energy assessment through this rulemaking is not practical, overstates benefits, understates costs, and is not authorized by the CAA. Since the energy assessment requirement impacts units other than BPH in a facility by including energy consuming systems, this rulemaking expands this BPH rulemaking to many other source categories. The Agency's authority under section 112 of the CAA for that expansion is unclear at best.

There is no basis to claim any benefits for the energy assessment requirement since 1) larger area sources typically have already performed extensive energy assessments and installed those projects with high economic returns that make sense from a safety, reliability, operability and capital management perspective, 2) smaller area sources have neither the expertise or wherewithal to execute such assessments, and 3) the proposal separately requires BPH tune-ups, EPA's claimed main source of energy assessment benefits⁵⁶ .

For smaller area sources, cost might be reasonable if they could avail themselves of the proposed 8 hour and 24 hour limit on assessment hours, but there is no chance of any benefits in those cases, since 8 and 24 hours is inadequate to meet the assessment requirements as outlined in Table 2 or to certify compliance (See the following comment).

Nothing in the proposal or proposal preamble addresses 1) the legality of imposing this requirement on sources outside the regulated source category (i.e., steam consumers), 2) how this assessment is linked to HAP emissions, the legal basis for this rulemaking (which are miniscule from light liquid fired equipment), 3) how equipment reliability, safety, and operability are to be protected, or 4) the real costs of the proposal.

B. The revisions to the definition of "energy assessment" to allow EPA to incorrectly claim a reduced energy assessment cost do not accomplish that goal and the true cost should be reflected in the beyond-the-floor analysis and the Information Collection Request or EPA must change the energy assessment requirements to match the time allowed. Other clarifications to the definition are also needed.

1. On page 80615 of the major source proposal preamble EPA states; "We have revised the definition of "Energy assessment" to change the maximum time from 1 day to 8 technical hours and from three days to 24 technical hours. This would allow sources to perform longer assessments at their discretion." All this change does is revise the criterion for when the violation occurs (i.e., it is now a violation if you fail to meet all the energy assessment criteria in Table 357 because to do so would require more than 8 hours or 24 hours, rather than 1 day or 3 days.). Nothing in the proposed energy assessment definition relieves sources from the Table 3 requirements for energy assessment content if they cannot complete the assessment in the specified time. In fact, proposed §63.11214(c) requires that a facility certify in the NCS that "the energy assessment was completed according to Table 2 to this subpart and is an accurate depiction of your facility." Thus, sources have no discretion whether or not to spend more time and it is false for EPA to assume the 8 and 24 hour limits have any meaning or to rely on those limits for the burden and cost analyses.

The Table 2 requirements involve significant technical work and thus will always require more than the 8 or 24 hours specified by EPA for facilities less than 1 trillion BTU per year. Thus, to avoid violating §63.11214(c) sources will always expend more than 8 or 24 hours. EPA needs to include a realistic time estimate in the record for the energy assessment and justify the real costs as required by section 112(d) of the CAA and provide that justification to the Office of Management and Budget and to the public, rather than setting artificial and unrealistic time limits to justify reduced cost estimates for this arbitrary requirement.

2. The definition is unclear whether the energy assessment applies to just boilers or to both boilers and process heaters. Since the size criterion (i.e., facility boiler and process heater energy consumption) is based on both boilers and process heaters, we would assume the proposed definition means the assessment must deal with both steam and process heat. However, the area source rule only deals with boilers and thus there is no basis for evaluating process heaters or process heat consumers. If the energy assessment requirements are finalized, the area source energy assessment must be limited to boilers and steam consumers. The definition wording, as exemplified in Item 4 below, should be clarified on this point.

3. Each of the three paragraphs in the definition call for evaluating "the boiler system and any energy use system" accounting for at least a specified percentage of the energy output. "Output" is a meaningless term related to consumers and that word should be changed to "production or consumption."

4. For example, to be clearer Paragraph 3 of the energy assessment definition should read as follows.

(3) In the Energy assessment for facilities with affected boilers and process heaters using greater than 1.0 trillion Btu per year, the boiler system and any energysteamuse system accounting for at

least 20 percent of the energysteamoutputproduction or consumption will be evaluated to identify energysteamsavings opportunities.

Paragraphs 1 and 2 of the proposed definition should be changed accordingly

C. Energy assessor qualification requirements should be generalized.

Proposed §63.11237 defines qualified energy assessor as follows. Qualified Energy Assessor means:

(1) Someone who has demonstrated capabilities to evaluate energy savings opportunities for steam generation and major energy using systems, including, but not limited to:

(i) Boiler combustion management.

(ii) Boiler thermal energy recovery, including

(A) Conventional feed water economizer.

(B) Conventional combustion air preheater, and

(C) Condensing economizer.

(iii) Boiler blowdown thermal energy recovery.

(iv) Primary energy resource selection, including

(A) Fuel (primary energy source) switching, and

(B) Applied steam energy versus direct-fired energy versus electricity.

(v) Insulation issues.

(vi) Steam trap and steam leak management.

(vii) Condensate recovery.

(viii) Steam end-use management.

(2) Capabilities and knowledge includes, but is not limited to:

(i) Background, experience, and recognized abilities to perform the assessment activities, data analysis, and report preparation.

(ii) Familiarity with operating and maintenance practices for steam or process heating systems.

(iii) Additional potential steam system improvement opportunities including improving steam turbine operations and reducing steam demand.

(iv) Additional process heating system opportunities including effective utilization of waste heat and use of proper process heating methods.

(v) Boiler-steam turbine cogeneration systems.

(vi) Industry specific steam end-use systems.

There are at least two major problems with this definition. First, as written, this definition requires a single person to have all of the capabilities and experience listed. Such a person likely does not exist. For instance, people who specialize in boiler combustion management will likely have no experience with condensate recovery or industry specific steam end use systems. If instead of a single person, the definition is meant to apply to a team (as most energy assessments require) that is not reflected in the time, burden or cost estimates used for this rule. Secondly, the definition requires expertise and experience that will not be needed. For instance, the definition requires process heater and process heat expertise, even though the area source proposal only applies to boilers and, therefore, only steam use. Similarly, most facilities do not have boiler-steam turbine cogeneration systems, yet they cannot employ an assessor who lacks that experience.

We recommend the definition be revised to the following.

Qualified Energy Assessor or Assessors means a person or persons who have demonstrated capabilities to evaluate energy savings opportunities for steam generation and major steam using systems, as applicable to the facility.

D. If the energy assessment requirement is finalized, the Table 2 Item 10 allowance for use of past energy assessments, must be amended to waive energy assessor approval and qualifications requirements.

Proposed Item 2 of Table 10 lists the elements that must be addressed in the energy assessment. In the introductory paragraph it states "An energy assessment completed on or after January 1, 2008, that meets or is amended to meet the energy assessment requirements in this table, satisfies the energy assessment requirement." However, to be acceptable an energy assessment must have been performed by an assessor approved by the Administrator and that assessor or team of assessors must have met all of the requirements in the proposed qualified energy assessor definition. As discussed in the previous comment, the energy assessor definition is unreasonably restrictive and it is virtually impossible that an existing assessment was done by a team that met all those specific requirements. Further, the assessor or assessors for a past assessment certainly were not approved by the Administrator. Thus, the allowance to use existing assessments, which we requested and fully support, is not usable in practice. A sentence needs to be added to Table 2 Item 10 that waives the energy assessor definition and approval where an existing assessment is being used to meet the energy assessment requirement.

E. If the energy assessment is finalized, the modifications discussed above must be made to make the hour limits meaningful. The certification language required for the NCS and §63.11214(c) also need to be modified to reflect the hour limits and to clarify that the assessment is a snapshot.

1. Proposed §63.11214(c) requires that the NCS certify that "an energy assessment of the boiler and its energy use systems was completed according to Table 2 to this subpart and is an accurate depiction of your facility." If the 8 hour and 24 hour limits on the energy assessment for facilities producing < 1 trillion BTU/year are made meaningful, most sources in those production ranges will not have completed energy assessments, since that amount of time is inadequate to

even get started. Thus, those sources will be unable to sign the proposed certification wording. For those sources alternate wording must be provided. We suggest the following be provided as an alternate certification.

This facility has expended at least 8 or 24 technical hours, as applicable, towards evaluating steam production and consumption efficiencies.

2. Proposed §63.11214(c) must also be revised to clarify that the facility is only certifying to the accuracy of the information used in the assessment as a snapshot. Since the assessment is a onetime requirement, the certification should indicate that it is only an accurate depiction of the facility at the time of the assessment, thereby removing any suggestion that a new assessment is needed if the facility changes.

F. If the energy assessment is finalized, the following clarifications are needed to the definition of energy assessment.

1. The definition of energy assessment has three categories based on facility heat input, but then requires that the assessment address "energy use systems." There is no basis for expanding the assessment beyond producers and users of steam or heat provided by boilers and process heaters subject to this rule (e.g., electricity users, imported steam users) and therefore the term "energy system" should be replaced with "steam and process heat consumers."

2. Each of the three paragraphs in the energy assessment definition call for evaluating "the boiler system and any energy use system" accounting for at least a specified percentage of the energy output. As in the previous item, the term "energy" is unclear and should be changed to "steam." Additionally "output" is a meaningless term related to consumers and that word should be changed to "production or consumption." Finally, it should be clarified the percent is the percent of the facility total steam production or consumption, as applicable.

3. For example, to address the above concerns, Item 3 of the energy assessment definition should be revised to read as follows.

(3) Energy assessment for facilities with affected boilers using greater than 1.0 TBtu per year, the boiler system(s) and any onsite energysteamuse system accounting for at least 20 percent of the affected boiler(s) energysteamoutputproduction or consumption, as applicable, at the facility will be evaluated to identify energysteamsavings opportunities.

Similar revisions to Items 1 and 2 of the energy assessment definition are also needed.

7. The compliance timing for boilers that stop burning solid waste must be clarified and it should be clarified that only when it is intended to permanently cease burning solid waste does the CISWI unit become subject to the appropriate NESHAP rule.

1. Proposed §§60.2145(a)(2) and (3), and 60.2710(a)(2) and (3) and the proposed definitions of CISWI unit specify that a unit that has been subject to CISWI remains subject for 6 months after ceasing to combust solid waste. On the other hand, §63.11196(d) of this proposal states:

(d) If you own or operate an industrial, commercial, or institutional boiler or process heater and would be subject to this subpart except for the exemption in §63.11195(b) for commercial and

industrial solid waste incineration units covered by part 60, subpart CCCC or subpart DDDD, and you cease combusting solid waste, you must be in compliance with this subpart on the effective date of the switch from waste to fuel.

"Effective date" is unclear in this context and should be clarified by specifically referencing the provisions of the CISWI rules that identify this effective date as being the date identified by the source for the transition from the CISWI rule to the area source rule and not the date the source ceases to burn solid waste or the effective date of the part 63 subpart JJJJJ rule.

2. Proposed §63.11196(d) deals with compliance timing for boilers and process heaters that have been subject to the CISWI rule, but stop firing solid waste and thus become subject to this major source rule instead. The language of this paragraph needs to be clear that this transition only occurs if the unit is stopping solid waste burning permanently. As currently wording, a temporary stoppage (which happens frequently at CISWI) units would appear to make this rule applicable rather than CISWI.

3. Citing process heaters in proposed §63.11196(d) is incorrect since the area source NESHAP only applies to boilers.

To address these issues (1 through 3) we suggest the following revision to §63.11196(d).

(d) If you own or operate an industrial, commercial, or institutional boiler and would be subject to this subpart except for the exemption in § 63.11195(b) for commercial and industrial solid waste incineration units covered by part 60, subpart CCCC or subpart DDDD, and you intend to permanently cease combusting solid waste, you must be in compliance with this subpart on the effective date of the switch from waste to fuel part 60 subparts CCCC or DDDD to this subpart as identified under the provisions of §§60.2145(a)(2) and (3), or §§60.2710(a)(2) and (3).

8. We support the use of Generally Available Control Technology (GACT) to set the PM limit for new oil-fired boilers at area sources, but the GACT model (NSPS Dc) only establishes a numeric limit for boilers burning fuels with greater than 0.5 % sulfur and EPA should follow that example in this rulemaking.

EPA finalized a PM emission limit in the existing final BPH NESHAP based on GACT58 for new oil-fired area source boilers and is soliciting comment on the level at which the limit was set. In this proposal, EPA stated⁵⁹ :

For the purposes of regulating PM from new boilers, we concluded that the GACT standards should consist of numeric emission limits for units with heat input capacities greater than 10 million Btu per hour or greater because these new units will be subject to the new source performance standard (NSPS) emission limits for PM, and the NSPS will require PM emissions testing. For units with capacity less than 10 million Btu per hour, GACT does not include a numerical emission limit because of technical limitations of testing PM emissions from boilers with small diameter stacks.

We agree with EPA's rationale to base these limits on GACT versus MACT. Basing the limit on NSPS Subpart Dc is justified, as EPA has recently reviewed that NSPS60 and determined that a PM limit of 0.030 lb/MMBTU (see 40 CFR 60.43c(c)) is appropriate. However, NSPS Dc

provides an exemption from the PM limit for units burning low-sulfur fuel at § 60.43c (e)(4), as follows.

an owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.50 weight percent sulfur or a mixture of 0.50 weight percent sulfur oil with other fuels not subject to a PM standard under §60.43c and not using a post-combustion technology (except a wet scrubber) to reduce PM or SO₂ emissions is not subject to the PM limit in this section.

Therefore, to reflect GACT, EPA should include a similar sulfur criterion in the area source NESHAP in applying the new source boiler PM limit. Boilers firing liquid fuels containing < 0.5 wt. % sulfur should only be subject to the work practice requirement to maintain a record that the liquid fuel fired contains < 0.5 wt. % sulfur. Such a work practice is justified since the low sulfur content indicates low PM emissions and thus meets the CAA §112(h) criteria of being infeasible to measure. [Footnote 54: 76 Fed. Reg. 80598 (December 23, 2011)]

[Footnote 55: 6000 square feet is our estimate of the square footage of a typical four unit residence, but EPA may have data to allow specifying a heat duty, which would be a preferential way of defining the exclusion (i.e., Residential boiler means a boiler providing only comfort heat and/or hot water firing up to ___ MMBTU/hr.)]

[Footnote 56: In originally proposing the energy assessment requirement, EPA stated at 75 Fed. Reg. 32026 (June 4, 2010) "The Department of Energy has conducted energy assessments at selected manufacturing facilities and reports that facilities can reduce fuel/ energy use by 10 to 15 percent by using best practices to increase their energy efficiency. Many best practices are considered pollution prevention because they reduce the amount of fuel combusted which results in a corresponding reduction in emissions from the fuel combustion. The most common best practice is simply tuning the boiler to the manufacturer's specification."]

[Footnote 57: Table 2, Item 10 of the proposal states "The energy assessment must include" [emphasis added] and then lists eight elements, some of which are major technical efforts.]

[Footnote 58: 76 Fed. Reg. 15574 (March 21, 2011)]

[Footnote 59: 76 Fed. Reg. 80537 (December 23, 2011)]

[Footnote 60: 72 Fed. Reg. 32759 (June 13, 2007) and 74 Fed. Reg. 5091 (January 28, 2009).]

Response: This comment pertains to the area source boiler rulemaking. Provided the commenter has submitted this comment to the area source boiler rulemaking docket, the response to this comment will be provided there.

Commenter Name: Heather Parent

Commenter Affiliation: Maine Department of Environmental Protection

Document Control Number: EPA-HQ-OAR-2002-0058-3691-A2

Comment Excerpt Number: 1

Comment: Comments on the Area Source Rule

Tune up date delay and stay

We are requesting EPA stay the effective date of the rule for 90 days as allowed under Clean Air Act section 307(d)(7)(B), so that the EPA can complete its reconsideration process and finalize the area source rule. EPA has requested comment on delaying the compliance date for the tune up work practice until March 21, 2013 or March 21, 2014. Maine DEP supports delaying the compliance date for this regulation until May 21, 2014. Maine DEP continues to receive several calls each month from sources just becoming aware of this regulation. Most Maine boiler owners have informed us they already perform tune ups to maximize their units' efficiency during Maine's cold winters, but not all tune up technicians perform tune ups as prescribed in the proposed rule. Several boiler owners had their boilers tuned this summer, but under the proposed rule would be required to do another costly tune up to fit the EPA prescribed method.

Modified Tune up procedure

Maine DEP disagrees with the removal of the tune up requirement for new boilers. EPA should require a modified tune up for new sources that focuses on the optimization of boiler efficiency. EPA should also allow for sources to request approval for modified tune up procedures from the delegated authority, similar to mechanisms provided in EPA's rules regarding stack testing and monitoring. Portions of EPA's tune up procedure as proposed in the regulation are not applicable to biomass boilers. EPA should use the boiler tune up definition provided in the Major Source Boiler MACT for biomass units. *"Tune-up", as defined in the proposed Major Source Boiler MACT rule, means "adjustments made to a boiler in accordance with procedures supplied by the manufacturer (or an approved specialist) to optimize the combustion efficiency."*

Seasonal boiler EPA proposed a definition for seasonal boilers with a less rigorous tune up schedule for these boilers. EPA should instead provide an exemption for "limited use" boilers in the Area Source boiler rule, consistent with the Major Source Boiler MACT.

Units switching from natural gas to another fuel should not be considered new units 40 CFR 63.11194 (d) states: *A boiler is a new affected source if you commenced fuel switching from natural gas to solid fossil fuel, biomass, or liquid fuel after June 4, 2010.*

We have many boilers manufactured and installed with fuel switching capabilities. Treating them as "new" when they are operated as originally designed does not make sense, and is inconsistent with the Major Source Boiler MACT.

EPA should establish a straight forward heat input exemption for the major source and area source boiler rules

Maine DEP supports EPA's intent to exempt small residential sized boilers. Unfortunately, the final hot water heater definition was complicated and difficult for implementing agencies and boiler technicians to understand, making applicability determinations very difficult. The proposed addition of the 1.6 MMBtu/hr threshold makes implementation more straightforward. However, Maine DEP believes this should be used as an overall applicability threshold for all types of boilers and fuels. If EPA retains the hot water heater exemption, EPA should include biomass in the definition as follows, "hot water heater means a closed vessel with a capacity of no more than 120 U.S. gallons in which water is heated by combustion of gaseous, liquid, *or biomass* fuel and hot water is withdrawn for use external to the vessel. Hot water boilers (i.e. not

generating steam) combustion gaseous, liquid fuel, or *biomass* with a heat input capacity of less than 1.6 million Btu per hour are included in this definition."

Response: This comment pertains to the area source boiler rulemaking. Provided the commenter has submitted this comment to the area source boiler rulemaking docket, the response to this comment will be provided there.

1Z. Other Out of Scope Comments

Commenter Name: David Gardiner

Commenter Affiliation: The Alliance for Industrial Efficiency

Document Control Number: EPA-HQ-OAR-2002-0058-3683-A2

Comment Excerpt Number: 8

Comment: We Reiterate Our Strong Support for the DOE-USDA Technical Assistance Program

We are extremely gratified to hear of EPA's forthcoming collaboration with the Departments of Energy and Agriculture to help facilities "develop compliance strategies, such as combined heat and power that are cleaner, more energy efficient, and that can have a positive economic return for the plant over time."²³ This kind of technical support is critical to help regulated entities understand and comply with the regulatory process. Moreover, because industrial facilities only replace their boilers every 15 to 20 years, the Rule creates a narrow window of opportunity to make substantial improvements to these systems. The Technical Assistance program leverages the Boiler MACT by enabling facilities to take advantage of these investment points. Our organizations and businesses are eager to lend support to EPA during this process.

We assume that the fact that this program was not mentioned in the December Rule is not a reflection of EPA's regard for the program and remain hopeful that it will be fully supported and funded by the Agency. We remain happy to work with the Administration to lend support to this initiative and to alert our networks of the opportunity. We look forward to collaborating with you as this effort moves forward and hope that you will identify ways that we can help popularize the program among regulated entities.

[Footnote 23: US EPA, Fact Sheet: "EPA Boiler Standards: Department of Energy and Department of Agriculture Technical Assistance for Boiler Operators and Owners (<http://www.epa.gov/airquality/combustion/docs/20110221doefs.pdf>).]

Response: This comment pertains to an issue that is outside the scope of this reconsideration action. The EPA has not prepared a response to this comment.