

May 9, 2011

The Honorable Lisa P. Jackson
Administrator
United States Environmental Protection Agency
Room 3000
Ariel Rios Building
1200 Pennsylvania Ave., NW
Washington, DC 20004

**Re: Petition for Administrative Reconsideration and for Amendment of
the Industrial Boiler MACT, Industrial Boiler GACT, and CISWI Rules**

Dear Administrator Jackson:

The following parties hereby petition the U.S. Environmental Protection Agency (“EPA” or “Agency”) for reconsideration and amendment of the National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters (Boiler MACT) (76 Fed. Reg. 1506 (Mar. 21, 2011)); National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers (Boiler GACT) (76 Fed. Reg. 15554 (Mar. 21, 2011)); and Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Commercial and Industrial Solid Waste Incineration Units (CISWI) (76 Fed. Reg. 15704 (Mar. 21, 2011)):

- American Forest & Paper Association (AF&PA)
- American Wood Council (AWC)
- Biomass Power Association (BPA)
- Chamber of Commerce of the United States of America (CCUSA)
- Corn Refiners Association (CRA)
- Energy Recovery Council (ERC)
- National Association of Manufacturers (NAM)
- National Oilseed Processors Association (NOPA)
- Rubber Manufacturers Association (RMA)
- Society of Chemical Manufacturers and Affiliates (SOCMA)
- Treated Wood Council (TWC)

Trade association petitioners’ member companies own and operate thousands of boilers and process heaters that will be subject to the Boiler MACT, Boiler GACT, or CISWI rules. The petitioners and several member companies submitted extensive comments on the proposed Boiler MACT, Boiler GACT, and CISWI Rules to Docket Nos. EPA-HQ-OAR-2002-0058, EPA-HQ-OAR-2006-0790, and EPA-HQ-OAR-2003-0119. We appreciate the fact that the final rules include numerous changes that were made in response to public comments in an effort to make the rules more workable.

Nevertheless, there still are several fundamental problems with the final rules that cause them to remain unachievable in parts, and thereby to be overly burdensome and unsupportable by the facts or the law. Accordingly, for the reasons detailed herein, we petition the Agency for administrative reconsideration and amendment of the Boiler MACT, Boiler GACT, and CISWI Rules.

Pursuant to § 307(d)(7)(B) of the Clean Air Act ("CAA"), EPA is authorized to reconsider a rule where it was impracticable to raise an objection during the period of public comment or if the grounds for such objection arose after the public comment period (but within the time specified for judicial review), and if such objection is of central relevance to the outcome of the rule. The Agency already has admitted that "certain issues of central relevance to these rules arose after the period for public comment or may have been impracticable to comment upon" and, therefore, "we believe that reconsideration is appropriate under section 307(d)(7)(B) of the Clean Air Act."¹ These issues include:

- Revisions to the proposed subcategories in the major source boilers rule;
- Establishment of a fuel specification in the major source boilers rule through which gas-fired boilers that use a fuel other than natural gas may be considered Gas 1 units;
- Establishment of work practice standards for limited use major source boilers;
- Establishment of standards for biomass and oil-fired area source boilers based on generally available control technology;
- Revision of the proposed subcategory for energy recovery units for CISWI units;
- Establishment of limitations on fuel switching provisions for CISWI units; and
- Providing an affirmative defense for malfunction events for major and area source boilers and for CISWI units.²

EPA also indicated that the following additional issues may warrant reconsideration and revisions:

- Revisions to the proposed monitoring requirements for carbon monoxide for major source boilers and CISWI units;
- Revisions to the proposed dioxin emission limit and testing requirement for major source boilers;

¹ 76 Fed. Reg. 15267, March 21, 2011.

² *Id.* at 15267.

- Establishment of a full-load stack test requirement for carbon monoxide coupled with continuous oxygen monitoring for major source boilers and CISWI units;
- Setting PM standards under generally available control technology for oil-fired area source boilers; and
- Certain findings regarding the applicability of Title V permitting requirements for area source boilers.³

Even though the Agency has already indicated intent to reconsider these issues, we nevertheless respectfully request reconsideration of these issues. We agree that the issues are of central relevance to the rules and that we did not have adequate notice that EPA might include these measures in the final rules. Additionally, we request administrative reconsideration of the issues identified herein for the reasons explained in this petition.

We note that EPA retains residual authority under CAA § 112(d)(6) to periodically review and, as appropriate, revise MACT standards. Recognizing that several of the issues identified below may not strictly qualify for reconsideration pursuant to §307(d)(7)(B) because fair notice was provided in the proposed rules, we alternatively petition EPA to amend the final Boiler MACT, Boiler GACT, and CISWI rules to make the changes described below for the reasons explained herein. We also ask EPA to review MACT floor units and MACT floor calculations for errors, as we have identified some biomass units that have been improperly classified (e.g., some units in the biomass stoker CO floor are not stoker units) and some analyses were not performed as documented (e.g., the solid fuel PM floor calculation does not include data from the correct number of units). Please note that this review was only performed in relation to certain source categories where we have particular concern and suspect that similar concerns could be identified by a thorough review of the database.

Thank you for your consideration of these important issues. While we believe we have identified the most substantive issues with the Boiler and CISWI rules and included them herein, we are certain that as we move forward into implementation of these rules we will have other technical issues such as monitoring and compliance demonstration that will need to be addressed in a rulemaking setting, rather than with guidance documents or compilations of questions and answers posted on the EPA website. Addressing technical issues in the rules themselves will promote consistency in implementation and enforcement and give more certainty to the regulated community. We look forward to working with you to resolve these issues as we identify them.

³ 76 Fed. Reg. 15267, March 21, 2011.

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Please feel free to contact Tim Hunt at 202-463-2588 on my staff as a representative of the coalition of industries if you have questions or need more information.

Sincerely,

A handwritten signature in black ink that reads "Donna Harman". The signature is fluid and cursive, with a long horizontal stroke at the end.

Donna Harman
President and CEO

On behalf of the listed trade associations

cc: Gina McCarthy
Janet McCabe
Joe Goffman
Peter Tsirigotis
Robert Wayland
Jim Eddinger
Brian Shrager
Toni Jones

Attachments

**AF&PA, AWC, BPA, CCUSA, CRA, ERC, NAM, NOPA, RMA, SOCMA, and TWC
Petition for Administrative Reconsideration and for Amendment of the Boiler
MACT, Boiler GACT, and CISWI Rules**

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Executive Summary

The Petitioners submitted extensive and detailed comments on the proposed Boiler MACT, Boiler GACT, and CISWI rules. Our comments and our members' comments represented a few of the thousands of comments EPA received on the proposed rules in August 2010. The volume of comments and the issues surrounding the development of the proposed rules necessitated several more months of careful consideration by EPA in development of the final rules. However, the court only allowed EPA a limited amount of time to consider all of the additional information and comments received following proposal. We understand EPA's obligation to meet the schedule set out by the court for publication of the final rules and we acknowledge that there were several improvements between the proposed and final rules; however, we believe that there are still many improvements that need to be made to the final rules to make them achievable technically and economically. We would also like to note that although this petition covers only the Boiler MACT, Boiler GACT, and CISWI rules, we also have significant concerns with the final non-hazardous secondary materials definition rule since it determines what units fall under CISWI as opposed to Boiler MACT, and many more fuel materials appear to be reclassified as solid wastes than originally expected. It is unclear if EPA fully considered the implications of these dramatic changes when it identified the best performing units for the MACT floor calculations for the various subcategories.

EPA has already indicated that it agrees a reconsideration is warranted for several issues related to the Boiler MACT, Boiler GACT, and CISWI rules, such as the additional subcategories established in Boiler MACT and CISWI rules, as well as the Gas 1 fuel specifications, carbon monoxide (CO) monitoring requirements, and dioxin/furan (D/F) requirements. We concur that these issues warrant reconsideration since the public was not given adequate notice-and-comment opportunity. We support the inclusion of new subcategories in the Boiler MACT and CISWI rules and have provided suggestions in this document for ways to improve the methods used to establish limits for these subcategories. We agree that a Gas 1 fuel specification is appropriate to allow gases other than natural gas and refinery gas to qualify for work practices, but the H₂S specification needs to be adjusted. We also believe the Agency was justified in not requiring CO CEMS for all boilers over 100 MMBtu/hr but additional variability needs to be taken into account in setting CO limits, sources that already have

CO CEMS must be considered when establishing compliance approaches, and the O₂ monitoring requirements need reconsideration, as they were not included in the proposed rule.

We are most concerned about the establishment of dioxin/furan emission limits under the Boiler MACT and CISWI rules that relied on a small amount of data that are largely below detection limits. There is a great deal of measurement uncertainty associated with quantification of dioxin/furan emissions at the low levels seen from industrial boilers, process heaters, and energy recovery units. EPA has set these standards without being able to provide industry with an understanding of how to prevent or control dioxin/furan emissions from industrial boilers and process heaters and has not assigned any costs for meeting these standards. EPA should follow the approach taken in the recently proposed Utility Boiler MACT and set work practice standards instead of numerical emission limits for dioxin/furan. EPA has ample authority to prescribe a work practice standard instead of a numeric emissions limit. Section 112(h)(2)(B) 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.” Such is the case for the proposed dioxin/furan standards – the proximity of the standard to the detection limit makes testing for compliance not technologically practicable, while the inability to accurately measure at the level of the proposed standard is economically impracticable because spending more money on the prescribed method will not resolve the inherent problem of setting the standard at the method detection limit. A reasonable work practice standard requiring good combustion practices is justified in this situation and would ensure that dioxin/furan emissions are minimized.

Also of high concern and great and perhaps unintended impact to the number of units affected by the CISWI rule is the removal of the definition of “contained gas” from the CISWI rule. This change was made between the proposed and final rules and was not justified or properly considered. The public had no opportunity to comment on the change, which has very broad implications, as described herein. Additionally, while we concur with EPA’s decision to subcategorize energy recovery units under the CISWI rule, we describe below the necessary revisions to the floor setting process and how startup and shutdown should be handled.

We continue to be concerned about the achievability of many of the new source limits, the solid fuel PM, CO, and dioxin/furan new source limits in particular. We believe that EPA needs to reconsider the methods and the amount of data used to set these limits to ensure energy flexibility and promote energy independence. The new source limits should not be so stringent as to discourage the use of renewable solid fuels. Biomass is a “clean” fuel in many of the same respects as the Gas 1 fuels. For example, a biomass-fired boiler typically will have far lower HCl and Hg emissions than a comparable, well-controlled coal-fired boiler. Perhaps more importantly, biomass-fired boilers produce no net CO₂ emissions, which makes the combustion of biomass an important tool in managing and reducing the Nation’s carbon footprint. Similarly, biomass is an abundant, renewable domestically-produced fuel that can help reduce reliance on foreign sources of fossil fuel and, thus, improve the Nation’s energy security.

Prescribing overly stringent HAP emissions limitations on biomass boilers will create a significant barrier to the continued expanded use of biomass fuels.

We support the decision by EPA to retain the PM surrogate for certain metallic HAPs. The evidence is compelling that PM is an appropriate surrogate for non-volatile metal HAPs and a PM standard provides a practical known way of monitoring and controlling these emissions. However, concern remains that the emissions data on which the solid fuel subcategory PM limits are based are not representative of, and do not reasonably reflect the characteristics of, certain older and smaller biomass boilers. As a result, the PM standards severely disadvantage the facilities that operate these boilers and put them at risk of closure. We offer two options for reconsideration that could address these concerns while still maintaining the existing PM limit. First, Section 112(d)(4) authorizes EPA to set health-based emissions limitations (HBELs) when establishing standards for HAPs under § 112(d). Section 112(d)(4) is a powerful tool that enables EPA to match the stringency of a HAP emissions limitation to the level determined necessary to fully protect human health. As a result, the standard is no more stringent and no less stringent than needed to get the job done. Inclusion of a health-based emission limit in the Boiler MACT will ensure facilities are investing resources in emissions reductions where they have a public health impact. Second, EPA should consider creating a new subcategory that isolates these at-risk boilers factoring in their size, type and class in setting an alternative PM limit. Such an approach would not appreciably affect the existing standard.

1. The Standards for Dioxin are Unlawful and Unachievable.

EPA Lacks the Legal Authority to Regulate D/F as a Category of Compounds

The final D/F standards are procedurally flawed. In the proposed rule, EPA explained that, for purposes of establishing the proposed emissions limitations, it “grouped the HAP into five categories” – including a category for dioxins/furans – on the grounds that “pollutants within each group have similar characteristics and can be controlled with the same techniques.” 75 Fed. Reg. 32018. EPA afforded no notice or opportunity for comment on its stated rationale for regulating D/F as a category of compounds, nor does the Clean Air Act provide for this approach. For both these reasons, the dioxin standards in the final rules are unlawful.

EPA explained that CO “has generally been used [in prior rules] as a surrogate for organic HAP,” but concluded for purposes of the Industrial Boiler MACT that D/F should be regulated separately “because, unlike other organic HAP, D/F can be formed outside the combustion unit.” *Id.* The proposed standards for D/F were expressed in terms of total “TEQ,” which is an approach that assigns a “toxicity equivalent” to D/F isomers using 2,3,7,8 TCDD as the toxicity baseline. *See, e.g., id.* at 32066 (Table 1, proposed emissions limits for new or reconstructed boilers and process heaters). Compliance is determined by multiplying the measured amount of each isomer by its corresponding TEQ and then summing that value for all isomers.

Many commenters asserted that the proposal to regulate D/F as a category of compounds was beyond EPA's authority because the § 112(b)(1) list of HAPs includes only two named D/F compounds – dibenzofuran and 2,3,7,8 tetrachlorodibenzo-p-dioxin. In the final rule, EPA responded by asserting that, "While dibenzofuran and 2,3,7,8 TCDD are two of the HAP listed in Section 112, all dioxin and furan compounds are considered to be POM and, as such, EPA has the authority to regulate these compounds under Section 112." 76 Fed. Reg. 15640.

EPA provided no explanation in the proposed rule of its purported legal authority to regulate D/F as a class of compounds. The legal justification was provided for the first time in the preamble to the final rule. This justification is not a "logical outgrowth" of the proposed rule because commenters could not have reasonably predicted at the time of proposal that EPA might rely on its POM theory in justifying regulating D/F as a class of compounds in the final rule. Indeed, there are no comments on this point in the record because none of the commenters actually did anticipate that EPA would take this tack. This is an issue of central relevance to the outcome of the rule because, if EPA's legal theory is ultimately determined (or proven) to be wrong, the categorical D/F standards will have to be rescinded and replaced with compound-specific limits or work practices.

Lack of notice and opportunity to comment aside, the substance of EPA's stated rationale for regulating the entire category of D/F compounds is also contrary to law. As noted above, the fact that Congress specifically identified only two D/F compounds in the § 112(b)(1) list of HAPs provides an unambiguous signal that EPA may regulate only those two specific D/F compounds and not other isomers or closely related materials. Thus, upon reconsideration, EPA must propose to replace the D/F standards in the final Boiler MACT rule with work practice standards or establish emissions limitations only for dibenzofuran and 2,3,7,8 TCDD.

The Dioxin Standards Are Unachievable

In addition to the legal issues noted above, there are technical flaws in the final rule that render its D/F standards unachievable. EPA proposed emission limits for dioxin/furan for 9 subcategories of units based on fuel and design criteria. The limits were based on a very limited data set (1 to 2 units in each floor) and the majority of the data were detection level limited (i.e., very few dioxin/furan test results were above the method detection limit). Some of the data were of poor quality due to errors in transcription or calculation methodology. The proposed limits were so low as to be largely unachievable, none of the boilers setting the floors employed any dioxin/furan control measures, and there is no information to suggest there are control measures that can be reliably employed to further reduce these already low emissions. In the final rule, EPA has retained the dioxin/furan standards for 12 subcategories of units, recalculating the limits based on a procedure to adjust the data according to representative detection limits, or RDLs. Data corrections and floor calculation methodology adjustments have resulted in improvements in some dioxin/furan emission limits (e.g., existing oil unit limit of 4 ng/dscm), but the majority of the limits remain unachievable and are not justified.

In the Boiler MACT regulatory impact analysis, EPA has not assigned any costs to compliance with the dioxin/furan limits:

The final rule requires all units that measure dioxin data below the method detection level to report that congener as zero. Based on the reported dioxin/furan data and associated detection levels available at the time of the final rule, most units will fall below the MACT floor levels if the non-detect congeners are treated as zero. For coal, 17 of the 27 tests would meet the existing limits, 17 of the 22 tests for biomass would meet the existing limits, and all of the liquid and process gas tests would meet the existing limits. Given these results and the fact that some units are installing ACI for mercury control, which is expected to have a co-benefit of reducing dioxin/furan emissions, the cost analysis does not estimate any control costs for achieving the dioxin/furan emission limits.⁴

Assuming compliance through reporting non-detect congeners as zero does not make sense and may not be consistent with existing reporting protocol. Assigning congeners as zero is only allowed by EPA procedures (Method 23, section 9.9) when determining total homologue groups, which uses a different analytical method than the isotope dilution method to identify 2,3,7,8 chlorine substituted isomers. In addition, some states do not allow reporting of non-detects as zero. EPA's logic does not make sense because EPA's baseline emission factors for many units without data are above the limits⁵, EPA projects only 11 units will install ACI, and EPA projects a dioxin/furan emission reduction of 23 g/yr across all fuels from implementation of the rule⁶. EPA cannot claim emissions reductions from a rule without associating some action on industry's part to comply. EPA does not have sufficient data on dioxin/furan emissions from industrial boilers and process heaters to be able to delineate how compliance with the standards is to be achieved. If these concerns are not enough, boiler operators and equipment manufacturers have no clear understanding of the proper methods to reliably reduce D/F emissions to come into compliance with the standards EPA has set.

In EPA's recently proposed Utility MACT (76 Fed. Reg. 24976), no dioxin/furan standards are proposed for coal and oil-fired EGUs because the majority of the data are non-detect (ND). The levels of D/F reported by industrial boilers are very low, similar to utility boilers. Of the 333 test runs included in EPA's emissions test database, 4.50% (15) are labeled as being below the detection limit (BDL) (i.e., all congeners reported as ND), 72.67% (242) are classified as detection level limited (DLL) (i.e., some of the congeners reported as ND), 21.92% (73) are labeled as above the detection limit (ADL)

⁴ ERG Memorandum, "Revised Methodology for Estimating Cost and Emissions Impacts for Industrial, Commercial, Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants – Major Source," February 17, 2011.

⁵ ERG Memorandum, "Revised Development of Baseline Emission Factors for Boilers and Process Heaters at Commercial, Industrial, and Institutional Facilities," January 2011.

⁶ US EPA, "Regulatory Impact Analysis: National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters," February 2011.

(i.e., all congeners reported above detection levels). The D/F data submitted by sources in response to EPA's Phase II Information Collection Request (ICR) reveals even further uncertainty in the data than meets the eye. D/F sampling and analytical methods offer unique challenges. Eastman's data for Boiler 30 reveal a further understanding of this uncertainty (Eastman has submitted these data to EPA). Every congener in each test run was either reported as ND or reported as a value that was flagged with a "J" qualifier. The "J" qualifier indicates the analyte was quantified with a concentration below the reporting limit, defined as below the lowest point on the calibration curve. Some of the congeners were also labeled "EMPC" (estimated maximum possible concentration), indicating that a peak is detected but did not meet all of the method criteria. Both of these "flags" indicate that there is a high degree of uncertainty associated with D/F data at the low levels found in industrial boiler stack gas. This test report also reveals that some D/F congeners were detected in the field blank, indicating background levels of D/F which cast further doubt and uncertainty on the reported analyte concentrations. An examination of one of the top performing coal-fired units, the unit at Miller Coors in North Carolina, reveals a similar high level of uncertainty. In this test, of the total 51 reported congener values, 21 were reported as "not detected" but the other 30 values were all flagged with the "J" qualifier. Therefore, even the top performers in EPA's dataset have results that have a high level of uncertainty. EPA is summing uncertainty upon uncertainty in each of the dioxin congeners to create an emission limit that cannot be technically justified. Test results with such uncertainty should not be used to set emission standards for entire source categories.

In setting the Boiler MACT and CISWI standards, EPA has stated that the emission limit should not be set below the capability of the applicable test method, which is defined as its limit of quantitation. Source testing professionals agree that this information is best obtained by conducting simultaneous emission tests with multiple sampling trains operated by different teams with analysis performed at different laboratories. However, in setting the PCDD/F standards, EPA has erroneously used the detection capabilities of best performing laboratories to determine method quantitation limits and has promulgated standards which are orders of magnitude below the quantitation limits of D/F in biomass boiler emissions. As demonstrated by the measurement issues noted; quantifying actual dioxin emission levels for the floor units is technologically impracticable and Clean Air Act Section 112(h)(1) supports establishing a work practice standard for D/F in the Boiler MACT, as was done in the recently proposed Utility MACT. At a minimum, EPA must reanalyze its data and set much higher D/F limits for both Boiler MACT and CISWI, since most of the measurements were well below the quantification limit of EPA Method 23 and there is significant uncertainty surrounding the measurements. Appendix A provides more detail on this topic.

2. In the Final CISWI and Solid Waste Definition Rules, EPA Fundamentally and Improperly Revised the Definition of what Constitutes a "Contained Gaseous Material," Resulting in the Potential for Many Boilers, Process Heaters, and Other Combustion Units, Including Combustion Devices

Covered Under Other MACTs, to be Reclassified as CISWI Units Because of the Gases they Combust.

On March 21, 2011, EPA published the final rule: Identification of Non-Hazardous Secondary Materials That Are Solid Wastes (76 Fed. Reg. 15456 (Mar. 21, 2011)) (NHSM Rule) and the final CISWI Rule. The NHSM Rule identifies non-hazardous secondary materials that are solid wastes when used as fuels or ingredients in combustion units. The final rules contain a significant change to EPA's longstanding interpretation of the term "solid waste," in that the Agency has announced that the term "contained gaseous material" should be construed for purposes of the NHSM and CISWI rules as including gases contained in pipes. In the past, EPA has not considered gases in pipelines to be "contained gaseous material."⁷ However, in the response to comments for the NHSM Rule, EPA states:

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."

NHSM, Response to Comments, at 212.

Similarly, in the CISWI Rule, EPA has deleted the definition of "contained gaseous material." 40 CFR 60.2265; 76 Fed. Reg. 15761. That definition formerly read as follows: "*Contained gaseous material* means gases that are in a container when that container is combusted."

⁷ See, e.g., 47 Fed. Reg. 27520, 27530 (June 24, 1982) ("EPA agrees with commenters that fume incinerators are subject only to regulation under the Clean Air Act and does not intend that Parts 264 and 265 regulations apply to these facilities."); RCRA/Superfund Hotline Monthly Summary, 9488.1986(03), available at RCRA Online ("[A] fume incinerator used only to destroy gaseous emissions from an industrial process is not subject to RCRA regulation since the fume input, being an uncontained gas, is not a solid waste...."); Memorandum from Matthew Straus, Chief, Waste Characterization Branch, to Clifford Ng, Engineer, EPA Region II (June 17, 1987) ("[M]ethanol-laden air from the drying and granulation step in a process, does not meet the definition of solid waste under RCRA because it is in vapor form and not confined in a container."); 54 Fed. Reg. 50968, 50973 (1989) ([O]ur authority to identify or list a waste as hazardous under RCRA is limited to containerized or condensed gases."); 56 Fed. Reg. 7134, 7200 (Feb. 21, 1991) (Activated carbon air pollution control device is not RCRA regulated because the process gas "being treated is not a solid waste (it is an uncontained gas)."); 2000 CISWI Rule Response to Comments, at 15 ("Incinerators used as air pollution control devices and flares would not be covered by the CISWI standards and guidelines because they are not burning contained gases.").

As a result of these two rules, gases in pipelines, ducts, and vents that are combusted must meet the standards promulgated under the CISWI Rule, unless the gases are combusted in air pollution control equipment associated with the CISWI unit itself.

During the development of the 2000 CISWI rule, commenters asked that EPA expressly exempt from CISWI standards and guidelines any combustion device whose function is pollution control mandated by another federal or state requirement, including flares burning surplus, by-product, blast furnace gas. EPA responded by saying:

Incinerators used as air pollution control devices and flares would not be covered by CISWI standards and guidelines because they are not burning contained gases. The definition of solid waste includes only "... solid, liquid, semisolid, or contained gaseous materials..." A definition of "contained gaseous material" has been added to the CISWI standards and guidelines to clarify that only gases that are in a container when that container is combusted are covered by CISWI standards and guidelines.

Commercial and Industrial Solid Waste Incineration Units: Background Information Document for New Source Performance Standards and Guidelines, Public Comments and Responses (EPA-453/R-00-008) (Nov. 2000), at 15 (2000 CISWI Rule Response to Comments).

As noted above, the definition of contained gaseous material has been deleted from the CISWI Rule and, in the Response to Comments on the NHSM Rule EPA has reinterpreted the definition of "contained gaseous material." As a result, flares and other air pollution control equipment (such as regenerative thermal oxidizers (RTOs) and fume incinerators) not directly associated with a CISWI unit could now be considered solid waste incinerators subject to CISWI standards. In addition, industry boilers, furnaces, and kilns that are used to burn process gases could be considered CISWI units. This modification is so impactful that essentially any process emissions being controlled by a combustion device would now subject that combustion device to the CISWI standards.

EPA's new interpretation of the term "contained gaseous material" has changed without notice or an opportunity for comment. At no stage of the NHSM rulemaking process did EPA provide any notice that it intended to change its interpretation of the term "contained gaseous material." Neither the advanced notice of proposed rulemaking (74 Fed. Reg. 41 (Jan. 2, 2009)) nor the notice of proposed rulemaking (75 Fed. Reg. 31844 (June 4, 2010)), nor the final NHSM Rule (76 Fed. Reg. 15456 (Mar. 21, 2011)) includes any discussion of this term. EPA did receive a comment on the proposed rule from the American Chemistry Council and a comment from the American Petroleum Institute, asking that EPA clarify that contained gaseous material includes only gas in a container. These comments assumed that is what EPA intended and merely sought clarifying language.

Similarly, the proposed CISWI rule (75 Fed. Reg. 31938 (June 4, 2010)) provided no notice that EPA intended to change its interpretation of the term "contained gaseous material." EPA did not even propose to delete the definition of that term from the 2000

CISWI rule. 75 Fed. Reg. at 31983. However, this definition is deleted in the final CISWI Rule with no discussion of this change in either the preamble or the response to comments document. 76 Fed. Reg. at 15761.

The only place where EPA indicates that it has changed its interpretation of “contained gaseous material” is in the response to comments on the NHSM Rule, as noted above. This language belies EPA’s promises of transparency in rulemaking and does not provide adequate notice to the regulated community that a change in interpretation has taken place, much less an opportunity for comment.

Additionally, this issue is of central relevance to the CISWI Rule, as EPA’s new interpretation of the term “contained gaseous material” would substantially expand the universe of combustion devices that would be considered solid waste incinerators subject to the CISWI Rule. Thus, EPA must include this issue in the CISWI reconsideration proceeding. In our view, there is no basis or justification under the law for EPA to change its longstanding interpretation that the term “contained gaseous material” includes only gases in a container. We do not believe, based on our conversations with EPA since the promulgation of these rules, that the Agency intended to broadly expand the universe of affected facilities in this manner. EPA should reaffirm this longstanding position through reconsideration.

3. We strongly support and want to retain the PM surrogate for Certain Non-Mercury Metal HAPs; We Believe the Final Industrial Boiler MACT Needs to Also Accommodate a Certain Class of Biomass Boilers

We support the decision by EPA to retain the PM surrogate for certain metallic HAPs. The evidence is compelling that PM is an appropriate surrogate for non-volatile metal HAPs and a PM standard provides a practical known way of monitoring and controlling these emissions. We have member companies who strongly support the continued ability to use the PM surrogate. However, concern remains that the emissions data on which the solid fuel subcategory PM limits are based are not fully representative of, and do not reasonably reflect the characteristics of, certain older and smaller biomass boilers. As a result, the PM standards severely disadvantage the facilities that operate these boilers and put them at risk of closure.

We offer two options for reconsideration that could address these concerns while still maintaining the existing PM limit and the PM surrogate. The first is a health-based approach and the second requires the creation of a new subcategory. Both would retain the current PM limit while working to create flexibility for a class of boilers that are sufficiently distinct that an alternative approach is justified and required. A health-based approach for acid gases should be considered separately from one for manganese and the metallic HAPs.

Health-Based Approach

In the preamble to the proposed Industrial Boiler MACT, EPA acknowledged its authority under CAA § 112(d)(4) to establish health-based emissions limitations

(“HBELs”) for threshold pollutants in lieu of a MACT emissions limitations. However, the Agency proposed not to establish any health-based emissions limitations “[g]iven the limitations of the currently available information (*i.e.*, the HAP mix where boilers are located, and the cumulative health impacts from co-located sources), the environmental effects of HCl, and the significant co-benefits of setting a conventional MACT standard for HCl.”⁸ Nevertheless, EPA asked for comment on a wide range of issues related to the justification for setting health-based emissions limitations and the method by which they should be set.

AF&PA and petitioners submitted comments explaining why EPA’s legal and factual concerns about setting HBELs are unfounded and presented data and information that would support HBELs for HAP acid gases and manganese. In particular, we pointed out that EPA had failed to provide an explanation as to why it adopted HBELs in the 2004 Industrial Boiler MACT standard, but reversed course in the 2010 proposed rule. We further explained that EPA had failed to provide a rational basis for rejecting HBELs when, by definition, an HBEL must be set at a level that protects public health with an ample margin of safety. AF&PA also presented detailed information demonstrating that HAP acid gases and manganese are threshold pollutants and explaining how HBELs could be established in a prudent, protective, and practicable manner. Lastly, AF&PA explained how an HBEL for manganese could be implemented in conjunction with a total select metals standard for other non-volatile HAP metals such that the suite of HAP metals limits would be more closely tailored than an aggregate PM surrogate emissions limit alone.⁹

In the final rule, “EPA decided not to adopt an emissions standard based on its authority under section 112(d)(4).”¹⁰ The Agency asserted that the use of § 112(d)(4) is discretionary and “it is appropriate for EPA to consider relevant factors when deciding whether to exercise its discretion under section 112(d)(4).”¹¹ In support of its decision not to adopt HBELs, EPA cited: (1) its ongoing concern about potential cumulative effects on health and the environment; (2) its belief that the CAA forbids EPA from using HBELs to exclude sources from regulation (which EPA said some commenters had suggested); (3) the “collateral benefits of reducing non-HAP air emissions; and (4) the fact that, for manganese in particular, it did not address or solicit comment on a possible manganese HBEL in the proposed rule.”¹²

Reconsideration of EPA’s final decision not to set HBELs is needed and particularly justified given the Agency’s failure to acknowledge and respond to the detailed comments explaining why HBELs are needed and how they are justified under the facts and the law. This is an issue of central relevance to the Rule because the Agency’s

⁸ 75 Fed. Reg. at 32032.

⁹ See for example AF&PA Comments at 141-171.

¹⁰ 76 Fed. Reg. at 15643.

¹¹ *Id.*

¹² *Id.* at 15643-15644.

failure to set HBELs has caused the acid gas and non-volatile metals standards in the final rule to be far more stringent than needed to protect health and the environment with an ample margin of safety, which will needlessly impose billions of dollars of excess costs on affected sources.

EPA failed, for example, to explain why HBELs could not be established in a manner that allows for consideration of site-specific characteristics – as petitions suggested in comments and as EPA adopted in the 2004 Industrial Boiler MACT. Similarly, EPA apparently ignored AF&PA and other commenters who agreed that HBELs must be emissions standards and that § 112(d)(4) should not be used as a mechanism to excuse certain affected sources from regulation. EPA also failed to explain why consideration of the co-benefits of non-HAP emissions reductions is a rational basis for not setting HBELs in the current rule when it clearly was not considered a barrier to setting HBELs in the 2004 rule. These and other similar flaws and gaps in the Agency's reasoning demand reconsideration of the decision not to set HBELs.

In conducting reconsideration on this issue, petitioners request that EPA consider a full range of possibilities, including establishment of specific subcategories where HBELs would apply, in order to give the most consideration to cost and regulatory flexibility issues. The reconsideration proposal should fully explore a possible HBEL for HAP acid gases – HAPs for which a particularly compelling case can be made that HBELs are appropriate and necessary. AF&PA submitted extensive scientific information in its prior comments demonstrating that HCl, HF, chlorine, and HCN are threshold pollutants. If EPA has any lingering concern on this point, it should identify the potential issues and ask for specific comments. In addition, the purported problems with “co-location” are easily resolved, in the first instance because EPA has ample authority to focus its risk assessment only on industrial boilers and, in the second instance, because a standard that allows for consideration of site-specific characteristics will prevent EPA from having to set a least-common-denominator standard keyed to hypothetical worst case conditions. The “co-benefits” issue also should be robustly assessed, particularly in light of the fact that a § 112 standard is wholly unsuited to effectively addressing criteria pollutant issues to which a substantial portion of the CAA is specifically dedicated to resolving.

The possibility of a manganese HBEL also should be fully explored. Perhaps the more important issue is how such an HBEL would be implemented in practice. It goes without saying that a manganese HBEL provides no meaningful relief if affected sources are also required to comply with a PM limit (which is an appropriate surrogate for all non-mercury HAP metals, including manganese). To solve this problem, AF&PA and others argued in their comments that a manganese HBEL should be implemented in conjunction with an alternative “total select metals” (“TSM”) standard (see additional comments in Section 4 below) to ensure that the full range of non-volatile HAP metals is appropriately addressed. A manganese HBEL appropriately set and combined with a TSM alternative would provide economic relief for many rurally-located small wood-fired boilers where manganese is the primary HAP metal and there is no health impact to the surrounding location. Installation of sophisticated PM controls on these boilers will not

be economically feasible for some companies, due to economic conditions and small operating margins, nor will they provide any additional environmental benefit where a HBEL is justified. Such approaches should be considered in the reconsideration proceeding.

New Subcategory for Certain Biomass Boilers

As an alternative to the manganese HBEL and TSM limit, EPA should consider creating a new subcategory for smaller and older biomass boilers factoring in their size, type and class in setting an alternative PM limit. Subcategorizing these boilers would not appreciably affect the existing standard. Some biomass boilers especially those at wood product facilities operate multi-clones to control particulates. Multi-clones cannot meet the new PM limits and owners of boilers with multi-clones would face significant expenses for installing ESPs or fabric filters to meet the 0.039 lb/MM Btu limit.

Given the barely recovering economy and dim prospects for a housing recovery any time soon, industries that are dependent on the home building market can ill afford expenditures that harm their competitiveness. For mills with limited or no profits for the foreseeable future, investing \$5 to \$15 million in new particulate controls will put these facilities at risk of closure with a resulting loss of the jobs they support in their communities and up and down the value chain. These units are largely located in rural areas far away from PM non-attainment areas. Their emissions are small – on the order of 100 tons per year – so their emissions characteristics and potential impacts on health and the environment are markedly different from the biomass boiler population at large. Incremental PM reductions from moving from multi-clones to ESPs or fabric filters on these units will be minimal.

Therefore, there is ample evidence that the generally applicable PM standard is not appropriate or suitable for this class of boilers. In addition, this class of boilers is easily distinguishable from the general population of biomass boilers, which provides a rational basis for a subcategory to accommodate these boilers. Lastly, setting a separate PM standard for these boilers would not undermine the generally acceptable PM standard. For these reasons, EPA should create a subcategory for these boilers and establish a subcategory-specific PM limit.

4. EPA improperly failed to Adopt a Total Select Metals (TSM) Alternative for Particulate Matter (PM) in Boiler MACT.

In the proposed Boiler MACT, EPA proposed PM limits for all subcategories (except Gas 1) as a surrogate for non-mercury HAP metals. Although the original 2004 Boiler MACT had provided an alternative TSM standard, the proposed rule did not contain a TSM option and the final rule also does not contain a TSM compliance option. EPA recently signed the proposed Utility MACT rule, which provides a choice between complying with a PM or a TSM standard for coal-fired EGUs. The Utility MACT preamble does not explicitly state why TSM is provided as a compliance option for coal EGUs, but does state that PM is an appropriate surrogate when PM controls are used to reduce emissions of metals. 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.

We understand and agree with EPA's approach to using particulate matter as a surrogate for non-mercury metallic HAP since metals are a component of particulate matter 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. However, to enhance flexibility and cost-effectiveness in the proposed rule, we believe that EPA must also include 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 likely reduce the cost of the rule, allowing sources to comply using fuel analysis instead of annual or triennial stack testing and to design emissions reduction strategies around HAP metals instead of PM for certain categories of boilers where the addition of additional PM controls does not add to the health benefits of just controlling metal HAPs.

As noted above, EPA also should adopt, in conjunction with a manganese HBEL, an alternative TSM standard that does not include manganese. This option will be of particular importance to smaller biomass boilers to add flexibility and offer a lower cost compliance alternative that will still ensure protection of public health.

5. The CO Emission Limits for Certain Biomass Boilers in Boiler MACT are Unachievable and Should be Reconsidered and Amended.

In the proposed Boiler MACT, EPA included CO emission limits based on boiler design for 9 subcategories of units. Boilers with a heat input of 100 MMBtu/hr and greater were required to install CO CEMS and comply with these emission limits on a 30-day rolling average basis. EPA used only 3-run stack test data to set the proposed limits, and did not properly consider variability. In using this procedure, EPA did not consider the variability of CO emissions with fuel and load. Facilities are typically required to conduct stack tests at 90 percent of full load or more and during normal operating conditions, so a CO stack test is going to represent the best operation of any boiler, not emissions over all operating conditions. EPA acknowledged this fact in the preamble at 75 Fed. Reg. 32021: "We believe that single short term stack test data (typically a few hours) are probably not indicative of long term emissions performance, and so are not the best indicators of performance over time." AF&PA also provided graphical representations in its comments to demonstrate the variability of CO emissions for several boilers, and suggested that EPA analyze additional CO CEMS data to further investigate variability, rather than rely solely on stack test data.

In the final rule, EPA established CO emission limits based on boiler design for 11 subcategories. EPA still used only 3-run stack tests to set the limits, but instead of requiring CO CEMS, the final rule requires an annual stack test and continuous O₂ monitoring as an indicator of good combustion. EPA also adjusted the statistical method to calculate the MACT floor by using the 99.9 upper prediction limit (UPL) instead of the 99 UPL. In response to comments received on the measurement

capability of EPA Method 10 for CO, EPA adjusted any measured CO data below a calculated method detection level, which resulted in some higher numbers being used in floor calculations, but also resulted in lower variability (especially for new source floors), since the same number was utilized in all 3 runs for calculation of the UPL. EPA also promulgated requirements for work practice standards during startup and shutdown (however, 63.7500 states that operating parameter limits apply at all times, so that would not excuse a source from meeting the established O₂ parameter limit during startup and shutdown).

The CO emission limits must be reconsidered because the petitioners could not reasonably discern at the time of proposal the way in which EPA would formulate the final standards and, therefore, were deprived of the opportunity to submit meaningful comments on this key issue. For example, EPA created two new source categories, changed the statistical method used to analyze the emissions data, adopted a new approach to addressing test results below the method detection limit, created new work practices for startup and shutdown, and imposed completely new compliance methods. These issues are of central relevance to the final rule because they form a substantial part of the basis for the final CO emission limits, which are critically important parts of the rule.

Several commenters submitted continuous emissions monitoring data with their comments on the proposed rule that demonstrated CO emissions are highly variable – which only stands to reason given that most industrial boilers are load-following units where the firing rate frequently changes based on changes in power or steam demand. We continue to believe that EPA has not gathered enough data on the variability of CO emissions from boilers in each subcategory and EPA did not sufficiently address our comments related to the variability of CO emissions. During the reconsideration proceeding, EPA will have the opportunity to solicit additional information from our members and other affected industry groups, which even more clearly will demonstrate the variable nature of CO emissions.

Based on conversations with boiler and burner vendors, there are certain boiler and burner designs that cannot achieve the CO emission limits with a simple tune-up, especially in cases where a low NO_x limit must simultaneously be achieved or where biomass is being burned with coal. AF&PA has heard from some of its members that biomass stoker boilers that already have recently modified over-fire air (OFA) systems cannot consistently achieve 490 ppm CO as a short-term standard, especially spreader-stoker boilers of older design. In addition, other companies have stated that in order to make combustion modifications to comply with the CO limits (and hopefully the dioxin/furan limits), they will have to install additional NO_x control to prevent exceedances of their NO_x limits as a result of compliance with the low CO limits. This of course will only come with a fuel/power efficiency cost, resulting in additional GHG emissions.

In addition, there remain situations where an evaluation of CO variability over all fuel and load conditions needs to be taken into account. In the final rule, EPA's revised floor

methodology did not take into account the fact that some units already have CO CEMS installed as required by their air permit (e.g., as BACT monitoring). Although it may have been EPA's intent to establish a CO limit that a source would meet by performing an annual 3-hour stack test at full load, sources that already have CO CEMS will have to meet the limit on a continuous 3-hour average basis. Based on our analysis of CO CEMS data from some of the top performing units, there will be many periods where this is not feasible (see Appendix B). EPA should request additional CO data from the top performers, especially where CO CEMS data are available, and should determine an alternate form of the CO standard for each subcategory, based on use of CO CEMS and a 30- to 60-day averaging period.

Finally, we continue to have concerns about data quality and representativeness of floor units. For example, the MNWeyerhaeuserIrontonEU 001 - 4 Cell Furnace, ranked 12 of 12 in the Biomass Stoker CO floor, is actually a fuel cell, and not a stoker¹³. We also believe that the MNAndersonCorpBayport Boiler Nos. 11 and 12 are biomass suspension burners, not biomass stoker units. The INConsolidatedGrainandBarge boilers may have been burning >10% TDF during the CO stack test, so should not be in the biomass floor. In addition, the MILPCSagola TOH-Wood unit is designated as the top performing biomass stoker for CO but is an old Geka burner design and is typically only operated at 60 percent load. This unit cannot be operated at full load because it exceeds State permitted CO limits. When this unit is operated at full load, it is supplemented with natural gas. This unit will not represent the design/operation of any future new biomass stokers. We have also heard from vendors that they cannot guarantee the new source coal and liquid CO limits. EPA should review the units in each floor to ensure that they are properly categorized, that units setting the new source floors are representative of future new boilers, and that there are adequate data to incorporate variability into the floor-setting process.

6. EPA's New Source Limits for Boiler MACT are Unachievable for Many Subcategories.

In the proposed Boiler MACT, EPA included new source emission limits based on boiler design for 9 subcategories of units. Data were reviewed for boilers burning at least 10 percent of the fuel represented by each subcategory, and the lowest stack test average was used to rank boilers by emission level. The new source emission limits are based on the 99 percent upper prediction limit (UPL) of the emission test data available for the unit with the lowest test average in each subcategory. In addition, the new source limits were set on a pollutant-by-pollutant basis, so they do not represent the actual overall performance of any one boiler or process heater. Capabilities of test methods and validity of submitted data were not considered, so some of the new source limits were below the practical limits of detection of EPA test methods. Fuel variability

¹³ Weyerhaeuser Company on May 2, 2011, submitted information and a revised ICR Phase I survey to EPA to assist in correcting the misplacement of this unit in the stoker subcategory.

factors were not considered for all of the sources. Due to these factors, many of the proposed new source limits were so low that manufacturers were not willing to guarantee the emission levels for new boilers due to the limitations of technology and measurement techniques.

In the final rule, EPA established new source emission limits based on boiler design for 11 subcategories. In response to comments received regarding representativeness of new source boilers with respect to the particular fuels burned, EPA attempted to pick the top source burning a representative fuel (e.g., clean biomass instead of deinking residuals, fuel oil instead of liquid process anhydrides waste) and burning 100 percent of the fuel represented by the subcategory. However, EPA continued to use a pollutant-by-pollutant approach instead of a source-based approach, which results in only 2 boilers in the entire database (one burning liquid and one burning 70% natural gas with 30% biomass) being able to meet the new source limits. The new source limits are orders of magnitude below current NSPS and typical BACT requirements.

EPA also did not evaluate the stack test data used to set the new source limits to determine if emissions were above method detection levels (e.g., whether enough particulate was collected on the filter during a Method 5 stack test to ensure a reliable result, or whether the dioxin/furan test results actually detected any emissions of dioxin/furan). EPA should not set new source limits based on data that are below the measurement capabilities of the analytical and stack test methods. For example, examination of the data used to set the new source solid fuel PM limit (IAArchersDanielsMidlandDesMoines Asea Boiler #1) indicates that one stack test reported PM as below the detection limit and the second available test report indicated that only about 1.5 mg were caught on the filter. Published studies indicate that the practical quantitation limit of Method 5 is 3 to 6 mg, and a 1996 EPA-funded study indicated that the minimum PM catch for ± 10 percent accuracy of Method 5 is 7.2 mg¹⁴. EPA should not use these data to set the new source standard, as the data are below the detection capabilities of the method. Instead, EPA simply replaced the three runs reported as below the detection limit with 0.0002 lb/MMBtu, which eliminates any variability and still represents a questionable result. Examination of the unit ranked number 2 in the solid fuel PM floor (IAMonsantoMuscatine Boiler #8) indicates the new source limit would be an order of magnitude higher if all data from this unit were used, as there are 18 test runs available from this unit that show emissions variability.

NCASI¹⁵ examined the ability of testing companies to measure PM emissions from sources to demonstrate compliance with the promulgated MACT standards for several

¹⁴ "Minimum Detection Limit for Method 5," R. Shigehara, Entropy Incorporated, EPA Contract No. 68-D2-0163, Work Assignment 3-06, September 30, 1996.

¹⁵ The National Council for Air and Stream Improvement (NCASI) is an independent, non-profit research institute that focuses on environmental topics of interest to the forest products industry.

source categories as shown in Table 1. The table shows the amount of PM that would be collected in a Method 5 train when tests are conducted on existing and new boilers operating at the promulgated PM emission standards and typical levels of oxygen observed during normal operation.

Table 1. PM Mass Expected To Be Collected During Performance Tests of Boilers

Source	Emission Standard, lb/MMBtu	Sample Volume, scf	Typical Stack Percent O ₂	Method 5 PM Mass, mg
Biomass, New	0.0011	90	10.0	2.5
Coal, New	0.0011	90	8.0	2.8
Oil, New	0.0013	90	6.0	4.1
Gas 2, New	0.0067	90	6.0	22.3
Biomass, Existing	0.039	30	10.0	29.4
Coal, Existing	0.039	30	8.0	33.4
Oil, Existing	0.0075	30	6.0	7.9
Gas 2, Existing	0.043	30	6.0	47.7

F factors used (dscf @ 0% O₂/MMBtu) - biomass - 9400; Coal - 9820; Oil - 9220; gas – 8740

As seen in Table 1, the mass of PM collected during performance test runs for boilers ranged from 2.5 to 47.7 mg. However, as pointed out in NCASI’s extensive comments on the boiler MACT proposal (U.S. EPA Docket EPA-HQ-OAR-2002-0058), the quantitation limit of EPA Method 5, based on analysis of simultaneous multi-lab Method 5 test data, is expected to be between 6-8 mg. Thus, the PM mass collected in three of the above eight cases (all new) would be well below the quantitation limit of the test method. Since sources typically design and operate their boilers at levels much lower than the emission standards to ensure compliance, this problem is further exacerbated. EPA should raise the emission standards to levels such that source operators can conduct tests and demonstrate compliance with the applicable standard.

EPA also did not provide enough consideration for variability of emissions, as 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 must amend the rule limits so that equipment vendors are able to guarantee boilers and process heaters can achieve the new source limits. Table 2 summarizes

the new source limits that we believe are the most problematic from the standpoint of achievability.

Table 2. Problematic New Source Limits

Subcategory and Pollutant	Proposed New Source Limit	Finalized New Source Limit	Notes
All D/F limits	See overarching discussion on D/F limits in Item 1.		
Solid Fuel PM	0.008 lb/MMBtu biomass 0.001 lb/MMBtu coal	0.0011 lb/MMBtu	Stretching the measurement capability of Method 5; should not use stack tests that did not collect adequate PM on filter. Vendors are hesitant to guarantee this performance level. Will also be very difficult to calibrate/ certify PM CEMS – cannot vary emissions enough with a fabric filter and at these low levels to develop calibration curve. PM CEMS will not be able to meet current performance specification and requirement to collect 4 data points per hour at this low level.
Liquid CO	1 ppm@3% O ₂	3 ppm@3% O ₂	Vendors cannot provide guarantees for new units at this level. This is based on a gas-fired unit burning liquid periodically, and is a 3-run stack test, where EPA assigned all 3 runs a value of 3 ppm (no variability) due to Method 10 accuracy. CO limits should not be any lower than 30 ppm based on 3x wet method accuracy criteria and CO vs. NOx issue (operating conditions that result in lower CO result in higher NOx).

Subcategory and Pollutant	Proposed New Source Limit	Finalized New Source Limit	Notes
Biomass Stoker CO	560 ppm @3% O ₂	160 ppm @3% O ₂	Will not be able to burn many types of biomass (e.g., green wood) and achieve this level; vendors will only guarantee this level on dry biomass. Unit setting this limit is a wood products unit using outdated design that would not represent a new unit; unit also currently only operates at 60% of load. Additionally, the methodology used does not account for any CO variability.
Coal PC/stoker/FB CO	90/7/30 ppm @3% O ₂	12/6/18 ppm @3% O ₂	Boiler vendors will not guarantee these levels. Additionally, the methodology used does not account for any CO variability. CO limits should not be any lower than 30 ppm based on 3x wet method accuracy criteria and CO vs. NO _x issue.
Gas 2 CO	1 ppm @3% O ₂	3 ppm @3% O ₂	Vendors cannot provide guarantees for new units at this level. Additionally, the methodology used does not account for any CO variability. CO limits should not be any lower than 30 ppm based on 3x wet method accuracy criteria and CO vs. NO _x issue.

Although EPA states that forcing fuel switching is not an appropriate control technology for this rule, these new source limits will in many cases force facilities to install new natural gas boilers instead of new biomass boilers. These new source limits will discourage facilities from replacing older solid fuel boilers with newer more efficient solid fuel boilers because they cannot build a new solid fuel boiler that meets the new source limits.

EPA should reconsider the new source limits because the promulgated limits are based on flawed and unreasonably limited data and analyses, resulting in standards that are unrealistic and unattainable in most cases. EPA currently lacks the available data to truly account for variability and should review the underlying data to ensure that the suite of limits actually represents what a new boiler will be able to reliably achieve and does not provide a disincentive to new construction of solid and liquid fuel boilers in the future. EPA is encouraged to take the time it needs during the reconsideration period to

request additional data from top performers and to review test data to ensure results below the limits of detection are not being used to set standards.

7. Revisions are Needed to the CISWI Floor Setting Process.

Section 129 of the Clean Air Act requires new and existing unit MACT standards to be based on “maximum degree of reduction in emissions” considering cost, and non-air health and environment impacts and energy requirements. It also requires minimum standards that are at least as stringent as the emissions limitations achieved by best performing unit(s) in a category, commonly referred to as “MACT floor limits.” In its CISWI rule proposal, EPA used a step-by-step statistically-based methodology to establish MACT floor limits for both new and existing units in each of four CISWI categories. Methodology steps included ranking units based on average performance as determined from EPA’s emissions database, selecting best performing unit(s), pooling test run data for the selected unit(s), characterizing the data as normally or log-normally distributed, and calculating an upper limit, all on a pollutant-by-pollutant basis.

Commenters stated that the proposed methodology was flawed, especially in light of EPA’s very limited database developed through its Information Collection Request, and that it resulted in overly stringent standards. This stringency was evidenced by the fact that in each and every case, over 100 in all, EPA’s floor limit (the minimum standard) ultimately became the final standard despite EPA’s detailed assessment of beyond-the-floor options. Of central relevance was whether the methodology properly accounted for the full range of emissions variability. Commenters offered many changes and corrections to the methodology and its implementation and encouraged EPA to ensure its floor limits reflect previously achieved standards.

In the final rule EPA used the same basic approach and steps in setting the MACT floors as in the proposal, but made two changes – 1) pooled data were judged log-normally distributed unless conclusively demonstrated otherwise, and 2) units with more data were adjusted to weight their influence on the pooled data calculations. EPA also employed its proposed alternate case upper predictive limit (UPL) instead of the base case upper limit (UL) to calculate the floors.

We believe that EPA’s revised methodology is still flawed. When coupled with its very limited database, typically a single 3-run test per pollutant for each CISWI unit, EPA’s rigid statistical approach has resulted in inconsistent, sometimes irrational, and economically challenging if not unachievable emission standards. EPA has a responsibility to obtain emissions data that represent the actual range and variability of operating conditions. These standards also encourage practices counter to EPA’s own solid waste management and energy policies. For example:

- Existing biomass power plants combusting clean forest-derived biomass and subject to Boiler MACT rules must meet a hydrogen chloride emission limit of 0.035 lb/MMBTU, equivalent to about 27 ppmdv¹⁶. Add even small amounts of

¹⁶ Parts per million dry volume corrected to 7 percent oxygen.

biomass of a type that EPA has now deemed “solid waste”, say construction or demolition wood or orchard stumps, to the fuel mix and the boiler becomes subject to CISWI Energy Recovery Unit (ERU) rules where the limit drops to 0.45 ppm_{dv7}, 60 times more stringent. Similarly, the CISWI mercury limit is sixteen times more stringent. On the other hand, the CISWI PM limit is 250 mg/dscm¹⁷, more than 5 times less stringent than the Boiler MACT PM limit (0.039 lb/MMBTU = 45 mg/dscm₇). While we understand why there is not likely to be perfect harmony between Boiler MACT and CISWI standards, the sheer magnitude of differences casts serious doubt on the viability of EPA’s floor-setting methodology. MACT is after all a technology-driven standard and there is no fundamental difference between the equipment or combustion properties of biomass-to-energy boilers subject to Boiler MACT and those subject to CISWI that would justify the radically diverse standards.

- In the above example, the exceedingly low CISWI hydrogen chloride and mercury limits, among others, will drive biomass power plants to abandon burning biomass “solid wastes” that would subject them to the CISWI standard or, due to economic constraints, cease operating altogether. This would result in landfilling of urban wood and landfilling or open burning of agricultural residues, in contradiction to EPA’s own Solid Waste Management Hierarchy, federal and state air pollution control programs, renewable energy policies, solid waste landfill “diversion” programs, and mandated permit requirements to generate emissions offsets from combusted biomass.
- EPA’s CO standard for the new CISWI biomass category is based on a single 3-hour test of the one unit identified as the best performer. The test consisted of three runs having identical results at 153 ppm_{dv7}. In this case and for other CO floor limits EPA had adjusted any measured CO data below a calculated method detection level, which resulted in some higher values being used in floor calculations, but also resulted in lower variability (especially for new source floors), since the same value was utilized in all 3 runs for calculation of the UPL. EPA conducted its statistical analysis and set the limit at 160 ppm_{dv7}, less than 5% above the average test result. It’s hard to understand how this limit reflects emission variability, especially since EPA itself recognizes that CO in particular is a variable pollutant stating “CEM data show that CO levels have a higher degree of variability than other pollutants” (76 Fed. Reg. 15646). Here and elsewhere EPA has applied its methodology to very limited data with seemingly no check on whether the resulting floor limit is rational.
- Section 129 requires new units to meet standards which are equivalent to or more stringent than existing units, but EPA’s methodology resulted in CISWI MACT floors limits for new solid/biomass ERUs that were much less stringent for six of ten pollutants. EPA “fixed” this problem by lowering the new unit limits down to the level calculated for the existing units for these six pollutants

¹⁷ Milligrams per dry standard cubic meter corrected to 7 percent oxygen.

explaining in table footnotes: “The NSPS limit exceeds [i.e., is less stringent than] the EG limit. The EG limit was selected as the NSPS limit.” (76 Fed. Reg. 15710, 15726, 15727). This is a further example of application of statistics to a small database yielding irrational results.

Given these types of unusual outcomes and the apparent limitations of EPA’s database and methodology EPA should reconsider its CISWI MACT floor-setting methodology. EPA should examine the reasonableness of derived MACT floor limits, erring on the side of achievability; otherwise it risks setting standards that have not been achieved in practice, in contradiction to the law. Specifically EPA should include reconsideration of the following methodological steps and issues raised by commenters:

- 1) The effect of waste composition. In the final rule, the selected best performing CISWI units frequently combusted “solid wastes” in small proportion to total inputs, or burned wastes that did not contain significant amounts of the constituents that would cause emissions (e.g., chlorine in biomass generating hydrogen chloride emissions). As a result, stringent emission limits for hydrogen chloride, cadmium, lead, mercury and dioxin/furan were driven more by waste characteristics and composition than the control technology employed at the best performing units. Stand-alone biomass power plants (as opposed to ERUs located at manufacturing facilities) are economically driven to burn large proportions of “solid wastes” such as urban wood and are particularly disadvantaged by these limits where incremental emission reductions exceeding 99% would be required. EPA should consider waste content variability adjustments, percent reduction alternative standards (see #4 below), geographic factors (e.g., biomass chloride content related to location) and other approaches that set achievable standards and otherwise level the playing field for units trying to responsibly utilize the nation’s biomass residuals.
- 2) Selection of upper limit value. In the final rule EPA selected the 99th percentile upper predictive limit of the pooled best performer data as the MACT floor for each pollutant. To the lay person 99% may sound like a very high compliance probability. To the CISWI operator however it means a 1% probability of failure, per pollutant, per performance test and represents an unacceptable compliance risk with numerous attendant consequences. For a two unit facility and nine pollutant limits non-compliance risk of a single performance test is $1-(0.99)^{18} = 17\%$, or approximately one failure every six years. In addition, setting the standard right at the selected upper limit does not allow for any compliance margin that every operator needs. For floors set using statistical metrics EPA should reconsider using a 99.9% upper limit as the MACT floor, as it did with the CO limit in the Boiler MACT rule.
- 3) Upper Predictive Limit (UPL) versus Upper Limit (UL). In the final rule EPA determined the MACT floor limit for each pollutant using individual test runs and a UPL calculation. The UPL as a statistical tool is misapplied in this case and should not have been used. The UPL’s fundamental premise is that run-to-run performance test results are randomly distributed over the entire population

distribution. EPA acknowledges this random premise (76 Fed. Reg. 15724) yet it provides no evidence supporting it. In fact, run-to-run results within performance tests at many CISWIs are not likely to be distributed randomly across the entire distribution. Rather, each of the three runs conducted during a performance test reflects conditions affecting a unit's emissions at the time of the test. Many of these conditions (e.g., waste characteristics, condition of combustor and air pollution control equipment, season of the year) are likely to remain the same or at least similar over the short duration (up to a few days) of a performance testing program. Individual run results in a short term performance test will therefore not vary randomly across the entire distribution of emissions that would be observed over longer (monthly or annual) time periods. Accordingly, when using the statistical approach to establish MACT floor limits EPA should reconsider use of the UL, as originally proposed in the CISWI rule, instead of the UPL.

- 4) EPA's upper limit (UL) and upper predictive limit (UPL) calculations do not properly account for both intra-unit and inter-unit variability. In its UL and UPL calculations EPA has used the square root of sample variance instead of the total variance. By substituting sample variance for total variance EPA has not properly accounted for total variability. Total variability is the sum of both within (intra) and between (inter) unit variability. Inter-unit variability is an additive value because the variance in emissions from each of the top performing sources is independent of one another and dependent on each individual unit's waste composition, combustor type, air pollution control type, test conditions and sample matrix. Intra-unit variability is the variability observed in test results from the same unit due to differences in waste composition, and process and air pollution control operation conditions during each test run. As such, if total variability is not addressed MACT floors will not represent limitations that can be achieved. Whether EPA uses the UPL or UL approach to determine MACT floors it should use the modified UPL or UL that accounts for total variance as used in the proposed Portland Cement Rule¹⁸ and the HWC MACT Rule¹⁹. EPA provided no rationale for why it did not use total variance instead of sample variance in the UPL or UL calculation MACT limit calculations. Its response only addressed use of UPL. The HWC MACT Rule estimated MACT floors that were achievable by the average of the best performing sources by using total sample variance.

The equation for the Modified UPL or UL that addresses total variance is:

¹⁸ Development of the MACT Floor for the Proposed NESHAP for Portland Cement, April 2009. EPA-HQ-OAR-2002-0051-2011.

¹⁹ Technical Support Document for HWC MACT Standards, Volume III: Selection of MACT Standards. U.S. Environmental Protection Agency, Office of Solid Waste and Emergency Response. September 2005, Pages 7-5 to 7-7. EPA-HQ-OAR-2004-0022-0453.

$$\text{UPL or UL} = \text{Mean} + t \sqrt{V_T}$$

Where Mean is the average of the best performing MACT unit averages and V_T is the total variance determined as the sum of the within (intra) source variance and the between (inter) source variance.

$$\text{Total Variance of } V_T = V_B + V_w,$$

Where V_B is the variance of the average of the best performing unit averages. As described above V_B is additive because the variance of each unit is independent of one another and dependent on individual units waste composition, combustor type, air pollution control type and sample matrix affects when sampling. V_w is the within or intra source variance and is calculated as the sum of the variances of individual runs within each of the best performing sources since individual unit test results will vary with waste composition, and process and air pollution control operation conditions during each test run.

- 5) Alternative percent reduction standard for hydrogen chloride, sulfur dioxide, and mercury. EPA's final emission standards are set as stack discharge concentrations. In the final CISWI rule preamble EPA did not address comments requesting an alternative percent reduction standard, but EPA did reject a similar comment in the Boiler MACT rule on the basis that it has no best performing unit data with which to determine appropriate values. We believe EPA is looking at this alternative too narrowly. If data specific to these units is unavailable, EPA should look beyond CISWI units to determine demonstrated emission reduction performance capabilities of air pollution control devices on combustion sources. EPA could rely on engineering calculations and vendor representations of achieved-in-practice results to define numerical best control efficiency performance of air pollution control equipment under Section 129(a)(3) provisions which allow standards to be based on "methods and technologies for removal or destruction of pollutants before, during, and after combustion." EPA should establish emission reduction (percent removal efficiency) standards for sulfur dioxide, hydrogen chloride and mercury as compliance alternatives to the concentration-based standards.
- 6) Common stack data. In the final rule EPA includes average test results obtained from a common stack serving multiple CISWI units as indicative of all units serving the stack. EPA offered no explanation to comments questioning the practice in the proposed CISWI rule, but EPA did respond to the same comment in the final Boiler MACT rule preamble. We strongly disagree with EPA's unsupported assertion made there that common stack data represents the performance of individual units. In the particular instance where EPA included common stack data from the NY Black River Generation facility to represent all three units, the identical emission values in three of the top five performers dampens the variability that would otherwise be observed had the units themselves been tested. EPA should reconsider its interpretation that data from

common stacks serving multiple units is representative of each of those units. These data should either be considered as one unit or, more appropriately, discarded from the database for purposes of determining variability.

- 7) Pollutant-by-pollutant approach. This issue has been vetted in other forums and is currently in litigation, but it bears repeating the request here on the basis of legal arguments presented by multiple commenters. The issue is central to any reconsideration request because of the impact that EPA's pollutant-by-pollutant approach has on the CISWI standards. EPA should reconsider its pollutant-by-pollutant approach, instead using unit-by-unit composite performance to rank and select best performing unit(s), especially considering the fact that EPA's database demonstrates that no CISWI unit has "achieved in practice" all of the final emission standards.

These reconsideration requests apply to EPA's methodology for setting MACT floor limits. In considering these petitions EPA should keep in mind that the floor limits are only the first step in setting the standards and represent the minimum stringency requirements. As such, given its database and methodology EPA should expect that in perhaps many cases it will need to go beyond the floor to set final standards, always evaluating the achievability of the final standards.

8. The CISWI Limits Do Not Consider Higher Emissions of CO and Other Pollutants During Periods Associated with Unit Start-Up and Shutdown When the Unit is Operating Under Non-Steady State Conditions.

In the proposed CISWI NSPS and Emission Guidelines, EPA did not provide separate treatment of startup and shutdown periods. The proposed CISWI Rule stated that the emission limits apply at all times, including startup, shutdown, and malfunction (SSM) periods.²⁰ EPA stated in the preamble that the Agency was not proposing separate emission standards during startup or shutdown for the following reasons:

"We determined that CISWI units will be able to meet the emission limits during periods of startup because most units use natural gas or clean distillate oil to start the unit and add waste once the unit has reached combustion temperatures. Emissions from burning natural gas or distillate fuel oil would generally be significantly lower than from burning solid wastes. Emissions during periods of shutdown are also generally significantly lower than emissions during normal operations because the materials in the incinerator will be almost fully combusted before shutdown occurs." [75 Fed. Reg. 31964]²¹

²⁰ 75 Fed. Reg. 31949

²¹ EPA also relied in part on the *Sierra Club* decision invalidating the Part 63 SSM general provisions, asserting that while the ruling "directly affects only [a particular] subset of CAA section 112(d) rules ..., the legality of source category-specific SSM provisions such as those adopted in the 2000 CISWI rule is questionable." 76 Fed. Reg. at 15737. This is flawed reasoning for three reasons. First, it does not necessarily follow that the court's holding extends beyond the bounds of § 112 – particularly in this

While this may be generally true for incinerators, this does not adequately characterize many energy recovery units (not all boilers startup on natural gas or distillate oil as evidenced by examining EPA's CISWI database, which includes startup fuel for each unit that submitted an ICR response). In addition, it also does not account for the fact that oxygen levels at startup can be very high and result in very high pollutant concentrations when correction to 7 percent oxygen is required. EPA recognized this fact in setting different emission standards for startup and shutdown under the recent revisions to the Portland Cement MACT standards and NSPS.²²

Many commenters objected to EPA's position and offered various alternatives, including establishing separate standards for these periods. In the final rule, however, EPA maintained its position that the same emission standards applicable during other operating periods will also apply during startup and shutdown. The preamble states:

In establishing the standards in this final rule, EPA has taken into account startup and shutdown periods and have not established different standards for those periods. The standards that we are finalizing are based on short term stack tests for pollutants that generally are not expected to vary significantly at startup and shutdown. The possible exception here is CO, which in some subcategories such as ERUs, could vary at startup and shutdown. However, the percent oxygen operating limits will ensure that combustion conditions are optimized and the CO is minimized. Solid waste and fuel-fired ERUs do not normally startup and shutdown more than once per day. Thus, we are not establishing a separate emission standard for these periods because startup and shutdown are part of their routine operations and, therefore, are already addressed by the standards. Periods of startup, normal operations, and shutdown are all predictable and routine aspects of a source's operation. We have evaluated whether it is appropriate to have the same standards apply during startup and shutdown as applied to normal operations, and as the rule is structured, well operated and controlled units should be able to meet the standards at all times. 76 Fed. Reg. 15738

In presenting this petition it is important that we distinguish between EPA's definitions of "startup period" and "shutdown" contained in the CISWI rule²³ which exclude all periods

case, where § 129 specifies that standards must be established pursuant to § 111, under which SSM provisions have been implemented since the early 1970's. Second, the 2000 CISWI SSM provisions are work practices, which qualify as "emissions standards" under the Act. Lastly, as explained above, the available data indicate that emissions during periods of SSM are significantly different from emissions during normal operations – even for the best performing sources. Therefore, some accommodation for SSM periods must be provided.

²² Rulemaking dockets EPA-HQ-OAR-2007-0877 and EPA-HQ-OAR-2002-0051

²³ 40 CFR 60.2265 and 40 CFR 60.2875 definitions: *Startup period* means the period of time between the activation of the system and the first charge to the unit.

when waste is burning, and the broader scope of startup and shutdown which includes those periods of transition when firing auxiliary fuel and/or solid waste when the unit is operating under non-steady state load conditions. For example, for an ERU this includes the period when bringing the unit on line after solid waste has been charged and started burning but before reaching steady state steam load as well as periods after waste has ceased being charged and waste combustion is completed. It is these transition periods in which the greater concern exists regarding variability of emissions and for which EPA has no emission data.

We disagree with EPA's unsupported assertions that the standards address startup and shutdown periods. Corrected emission concentrations can be significantly higher during startup and shutdown due to the unavoidable less-than-optimal emissions control performance during transitional (non-steady state) conditions. For example, at biomass ERUs combustion-related emissions such as CO, particulate (smoke) and opacity increase during the startup period when load and temperature are coming up to full load steady-state conditions. The Maine Department of Environmental Protection has stated "Wood and multi-fueled boilers produce large CO variations during startups as the boiler heats up. Start-ups can take up to 14 hours for some units. Shutdowns can also result in significant CO variability."²⁴ EPA itself recognized in the Boiler MACT that "CEM data show that CO levels have a higher degree of variability than other pollutants" (76 Fed. Reg. 15646). It doesn't matter whether these units are being fired with biomass fuel or biomass solid waste – the equipment involved is virtually identical and fuel combustion characteristic differences are minimal. Startup burners reduce emissions by preheating the combustion chamber and downstream equipment but are not sized to achieve full load temperatures and even if they were, could not completely avoid temporary sub-optimal combustion conditions as heat load shifts from auxiliary fuel to waste during startup and from waste to auxiliary fuel during shutdown. Air pollution control equipment goes through similar transient temperature and flow conditions, e.g. changing furnace temperature and velocity profiles make SNCR systems less effective during startup than during full load steady state conditions. These conditions are distinct from the less variable conditions that occur during typical steady-state operations. EPA's emission database excludes these periods and therefore does not capture this component of variability, leading to MACT floors that have not been achieved in practice.

EPA should open reconsideration of CISWI emission standards applicable during startup and shutdown periods. Reconsideration should include review of CEMS and other data and an engineering assessment of combustor and air pollution control equipment practices to establish performance capabilities. If EPA cannot use best

Shutdown means the period of time after all waste has been combusted in the primary chamber.

²⁴ Letter James P. Brooks, Bureau Director, State of Maine Bureau of Air Quality to James Eddinger, USEPA, February 4, 2010.

operating practices under Section 129 as it has under Section 112, then it should consider several options for separate and distinct startup and shutdown standards including:

- Uncorrected concentrations standards that reflect actual performance;
- Corrected concentration standards, accounting for concentration “blow up” when dilute conditions are corrected to 7 percent oxygen;
- Longer averaging times to accommodate short term swings; and
- For existing units requiring State Implementation Plans (SIP) to include a process which sets case-by-case numerical mass-based emission standards.

In the Boiler MACT rule, EPA had also proposed that standards apply at all times. However, in the final Boiler MACT rule EPA responded differently to commenters’ objections. In the final rule EPA incorporated a work practice standard in lieu of numerical limits for periods of startup and shutdown. The work practice standard requires sources to minimize periods of startup and shutdown following manufacturers’ recommended procedures.

If EPA recognized the need to modify startup and shutdown provisions in the Boiler MACT then it must also recognize the issue in the CISWI rule. The very same equipment and combustion conditions (boiler, air pollution control equipment, fuel/waste characteristics) that prompted EPA to change startup and shutdown provisions in the Boiler MACT also exist with the units regulated under the CISWI rule. EPA even acknowledges in both rules that sources can alternate between being boilers and incinerators based on whether they burn “fuels” or “solid wastes”. Yet EPA gave no explanation why the change made in the Boiler MACT wasn’t considered an issue in the CISWI rule. Accordingly, EPA should make accommodations for startup and shutdown in the CISWI rule just as it has under the Boiler MACT.

EPA should expand definitions of “startup period” and “shutdown” in 40 CFR 60.2265 and 40 CFR 60.2875 to include time periods of non-steady state operation after initial waste charging during startup and before auxiliary fuel firing during shutdown. Current definitions include only those periods when solid waste is not burning. These more limited definitions may have been appropriate for some categories which move seamlessly from auxiliary fuel to waste, but need to be changed to accommodate all units now included in the CISWI rule.

9. The Limits in Boiler MACT for Oil Fired Units are Unachievable.

EPA has grouped all boilers and process heaters firing any liquid fuel into one subcategory. Comments on the proposed rule suggested further subcategorization into heavy and light liquids. This further subcategorization was not incorporated into the final rule. In the response to comments, EPA states that although there are design differences between heavy and light liquid fired units, the approach taken in the final rule is consistent with that for solid fuels, as all solid fuels are grouped together for the fuel based HAP. EPA goes on to say that although solid fuel units are split for CO and

dioxin/furan, they are not splitting light and heavy liquid units and the floors are made up of a mix of light and heavy units.²⁵ The CO limits that EPA has finalized are made up of data that EPA has largely adjusted due to measurement capabilities of EPA Method 10, with little variability as a result. The floor units represent only 2 facilities, both burning distillate fuel oil. Additional issues with the data and methodology EPA used to set CO limits were discussed in Item 5. Also, an analysis of the CO data for heavy and light liquid units indicates that a very different CO limit would result for heavy liquid units when these units are treated as separate subcategories. This would indicate that EPA should be consistent with the Agency's treatment of fuel and design based subcategories by establishing separate CO emission limits for heavy and light liquid units. As indicated in Item 1, we believe that work practice standards and not emission limits are warranted for dioxin/furan under Boiler MACT.

The liquid PM limits are set using a very small amount of data, and are not representative of fabric filter control technology (which EPA states is the technology assumed to be MACT for PM), as none of the floor units have controls. There are only 18 data points used to set the PM floor, one of which is labeled as detection level limited (DLL). Therefore, the "top performers" are determined based on a very limited data set and reflect only combustion of distillate fuel oil or "anhydrides waste". In fact, no unit burning No. 6 fuel oil (even the one listed as having a fabric filter with sorbent injection) meets the liquid fuel PM limit based on the PM stack test and fuel firing information in the EPA database.

There are 79 units for which EPA has gathered Hg data, but only 8 stack tests. 71 units are assigned fuel analysis data, but represent only 14 facilities. There are 11 floor units, with 50 data points, of which only 10 (2 stack tests and 2 fuel analyses) are labeled as above the detection limit. This is a very limited amount of data and a very biased data set (primarily based on non-detect data) to be used to set Hg limits for units firing any type of liquid fuel. The Hg limits are again based on units with no Hg controls, but on the fuels with the lowest amounts of mercury.

The HCl floors are similarly developed with a small amount of data and are based in large part on non-detect data (only 5 of 35 data points used to set the floor are above the detection limit – 1 stack test and 1 set of fuel analysis data). However, for PABoeingRidleyPark, EPA should assign the Unit 033 stack test result to all of the facility's units, and not the fuel analysis data, as all of the facility's units are uncontrolled (the fuel analysis data are listed as non-detect and are lower than the stack test result). EPA should reconsider the HCl limit for liquid boilers because the selected top performing unit (TNInvistaChattanooga EU003 Vaporizer #2) emission test data show higher emissions than the limit set for existing liquid fired units (0.00062 lb/MMBtu for this unit versus the existing unit limit of 0.00033 lb/MMBtu). This seems to indicate a problem with EPA's floor setting methodology; the selected top performer should be able to meet the established limit.

²⁵ Response to commenter EPA-HQ-OAR-2002-0058-1869.1, Comment Excerpt Number 4.

We do agree with EPA's approach of assigning a fuel variability factor to the HCl and Hg data to improve the consideration of variability in setting the floor, but EPA should gather additional data to improve the representativeness of the floor units. EPA should reconsider its decision regarding further subcategorization of liquid units and should gather additional emissions information to ensure the final limits are achievable by boilers and process heaters burning liquids other than distillate oil or process liquids.

10. The Criteria for Qualifying as a Gas 1 Boiler/Process Heater in Boiler MACT Should Be Revised.

In the proposed rule, EPA established numerical emission limits for units burning gases other than natural gas or refinery gas (Gas 2 units) and established only work practice requirements for units burning at least 90 percent natural gas and/or refinery gas (Gas 1 units). EPA's justification for establishing work practices for Gas 1 units was technical infeasibility of measuring and controlling low levels of HAP emissions from these units. Industry submitted comments and other supplemental information demonstrating that emissions from many types of Gas 2 units were also very low and suffered from the same measurement and control difficulties.

In the final rule, EPA has established criteria for units burning gases other than refinery gas and/or natural gas to qualify as Gas 1 units. We agree that there should be criteria for gas-fired units to qualify for the Gas 1 subcategory, because the justification for requiring work practices for natural gas and refinery gas units are the same for many units firing other types of gases. The 4 ppmv H₂S and 40 ug/m³ mercury content criteria are based on the typical content of sweet natural gas. EPA assumed in its impacts analysis and Gas 2 MACT floor calculations that all gas-fired units burning gases other than coke oven gas and blast furnace gas would meet the Gas 1 criteria based on an evaluation of mercury content.

EPA stated in the preamble, "EPA has 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." 76 Fed. Reg. 15639. However, the H₂S levels selected as part of the Gas 1 criteria do not represent the typical content of refinery gas (Refinery NSPS 40 CFR 60, Subpart Ja limits H₂S composition of fuel gas prior to combustion to 162 ppmv H₂S on a 3-hour average basis and 60 ppmv on a 365-day average basis) and some other types of gases that have low mercury content will also have H₂S content greater than 4 ppmv (e.g., landfill gas, biogas, and certain process gases). For example, literature indicates that the typical range of anaerobic digester gas is 200 to 3000 ppm of H₂S. Typically, digester gas meeting a pre-combustion concentration of 200 ppm is BACT. Therefore, if H₂S is retained as part of the criteria to be eligible for inclusion in the Gas 1 subcategory, the limit should be revised to reflect the higher H₂S contents of other clean gases.

11. The Affirmative Defense for Malfunctions Is Unfounded And Is Not An Appropriate Substitute for An Alternative Standard Covering Periods Of Malfunction

In the proposed rule, EPA asserted 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.”²⁶ Rather than setting standards to cover periods of malfunction, EPA explained that it would instead rely on enforcement discretion – *i.e.*, if a true malfunction caused an affected source to exceed MACT emissions standards, “EPA would determine an appropriate response based on, among other things, the good faith efforts of the source to minimize emissions during malfunction periods, including preventative and corrective actions, as well as root cause analyses to ascertain and rectify excess emissions.”²⁷

In our comments on the proposed rule, we argued that EPA inappropriately assumed that malfunctions are not a distinct operating mode that even the best performers sometimes experience. We further pointed out that EPA has ample authority to establish work practice standards in situations where numeric emissions limitations are not practicable. Therefore, EPA should establish a work practice standard that would apply during malfunction periods.²⁸

In the final rule, EPA reiterated its belief that “it is reasonable to interpret section 112(d) as not requiring EPA to account for malfunctions in setting emissions standards.”²⁹ But, instead of dealing with malfunctions through enforcement discretion, EPA decided to establish an affirmative defense that affected sources could raise if EPA or a third party were to seek enforcement action against an exceedance that occurs during a period of malfunction.³⁰

EPA’s decision to establish an affirmative defense for periods of malfunction was not expressly raised in the proposed rule and cannot reasonably be considered a logical outgrowth of the proposal to deal with malfunctions using enforcement discretion. Needless to say, an affirmative defense (including detailed criteria, such as who has the burden of proof and what must be demonstrated to successfully mount such a defense) is a far cry from the wholly different proposal to rely on enforcement discretion. Commenters had no reason to believe that EPA would establish an affirmative defense in the final rule and had no opportunity to prepare and submit comments on the legal justification (or lack thereof) for establishing such a defense or on the specific criteria used to implement the defense.

²⁶ 75 Fed. Reg. at 32013.

²⁷ *Id.*

²⁸ See AF&PA Comments at 250-253.

²⁹ 76 Fed. Reg. at 15613.

³⁰ *Id.*

In addition, EPA's decision to establish an affirmative defense is of central relevance to the outcome of the rule. Affected sources under the final rule are "guilty until proven innocent." This is fundamentally incompatible with EPA's obligation to set emissions standards or work practices governing all periods of operation, including periods of malfunction. As a result, EPA must reconsider its decision to establish an affirmative defense for periods of malfunction.

12. PM CEMS Should Not Be Required in Boiler MACT or CISWI.

In the Boiler MACT rule (both proposed and final), EPA is requiring PM CEMS as the monitoring method for solid fuel and residual fuel oil fired boilers 250 MMBtu/hr or greater in size. In the CISWI rule (both proposed and final), EPA is requiring PM CEMS as the monitoring method for solid fuel and residual fuel oil fired energy recovery units 250 MMBtu/hr or greater in size. The installed PM CEMS will be required to meet Performance Specification 11 and also comply with Procedure 2 in Appendix F of 40CFR60. Comments were submitted on both rules describing how PM CEMS are inappropriate for combination fuel fired units and the limitations in their measurement capabilities. Further, Section 129 (c)(3) requires that any monitoring, test methods and procedures be validated on solid waste incineration units. PM CEMS have not been validated on any solid waste incineration unit. We believe that for the reasons described below, EPA should not require the installation of PM CEMS on boilers/energy recovery units burning solid fuel or residual oil.

In order for a CEM to be suitable for demonstrating compliance, it must be accurate and precise under all operating conditions and must have demonstrated the capability of operating for long periods of time without breaking down. However, as discussed below, these requirements are not met when considering installation of PM CEMS on industrial boilers/energy recovery units.

- (a) EPA has failed to provide any technical information regarding the suitability of PM CEMS as compliance monitors. In the MACT proposal EPA stated that PM CEMS are used at a variety of sources in Europe, and several electric utilities either have or are planning to install PM CEMS. Such general statements neither establish the performance capabilities of PM CEMS nor do they justify their use as compliance monitors. Prior to promulgating this requirement, EPA must provide data that support its findings that justify the use of PM CEMS as compliance monitors and show that such monitors have been validated on multi-fuel boilers and solid waste incineration units.
- (b) Among the instruments commercially available for measuring PM in stack emissions are those that use the principles of light scattering, optical scintillation, electrostatic induction and beta attenuation. The responses of several of these instruments are expected to be affected by the size and nature of the particles being emitted. Thus the calibration curve for such instruments would be expected to change as the fuel mix and operating load change. EPA has not published results of any study

examining these issues. EPA must provide data that confirm that one or more types of monitors are capable of holding their calibration given the changing nature of PM emissions from multi-fuel boilers/energy recovery units.

- (c) PS-11 specifies in Section 8.6 (4) (i) that simultaneous PM CEMS and reference method tests must be performed to obtain three levels of PM mass concentrations. Section 8.6 (4) (ii) specifies that the three PM concentrations must be distributed over the complete operating range experienced by the source. Thus, if a source experiences high PM emissions for short periods of time due to process upsets, the facility would have to conduct the correlation tests at emission levels that could be above the emission standards. This raises the following issues:
- (i) How can a source operate above its PM limits in order to conduct stack tests to meet PS-11 requirements if it must be in compliance with its PM limits at all times?
 - (ii) EPA has assumed that PM emissions from a source can be controlled predictably within a narrow range through operating changes. If that is the case, what process did EPA go through to exclude the monitoring of process parameters as a less expensive alternative to continuous PM emissions monitoring?
 - (iii) EPA has not documented the process by which sources that are equipped with a fabric filter will achieve the targeted PM emission rates to satisfy the requirements of PS-11.
- (d) EPA has failed to document that currently available PM CEMS are capable of meeting the requirements of PS-11 when they are installed on multi-fuel boilers/energy recovery units.

In order to demonstrate that a PM CEMS is meeting the requirements of PS-11, a multi-fuel boiler will face some additional challenges not faced by say utility boilers burning coal. For example, a multi-fuel boiler/energy recovery unit burning a variety of fuels will need instruments available to continuously monitor the mass flow rate and moisture contents of all the fuels. This will greatly impact the ability of a PM CEMS to meet PS-11.

- (e) EPA has failed to document that PM CEMS are sufficiently precise and accurate to determine compliance with the applicable standards.

PM CEMS are required to meet the requirements of PS-11. PS-11 specifications include obtaining a correlation coefficient of ≥ 0.85 between measured and predicted stack gas PM concentrations, a 95% confidence

interval mid range at the mean PM CEMS response value within $\pm 10\%$ of the emission limit, and a tolerance interval mid range at the mean PM CEMS response value with a 95% confidence that 75% of all possible values are within 25% of the PM emission limit. This suggests there is a very high probability that many CEMS PM measurements that show up as exceeding the standard may actually be below the emission standard.

- (f) To measure and report PM emissions in lb/MMBtu, boilers/energy recovery units equipped with PM CEMS would also have to install stack gas moisture monitors. EPA has not published any performance specifications for stack gas moisture monitors. In the absence of such specifications, the reliability of the results of PM CEMS cannot be established.

We recommend that prior to requiring the installation of CEMS on biomass boilers, residual oil boilers, multi-fuel boilers and CISWI energy recovery units, EPA should sponsor field studies to (1) establish performance specifications for stack gas moisture monitors, and (2) determine the accuracy and precision of PM CEMS on biomass boilers, residual oil, multi-fuel boilers and CISWI energy recovery units, especially when load and fuel mix ratios are constantly changing.

- (g) PS-11 requires sources to conduct a minimum of 15 manual reference method tests. Section 2.4 (7) of PS-11 states: "Because the manual reference method testing for this correlation test is not for compliance reporting purposes, you may conduct the reference method test runs for less than the typical minimum test run duration of 1 hour." This section is in direct conflict with EPA's stated use of PM CEMS as compliance tools of the Boiler MACT standards. Additionally, EPA has failed to recognize that the promulgated PM standards for new sources would require many hours of sampling with the Method 5 train for a single run in order to collect a PM mass above the quantitation limit of Method 5. Thus calibration of PM CEMS would require many hours of testing at stable rates, which may not be feasible for many swing boilers.
- (h) There are 2 main types of PM CEMS: light scattering devices and beta gauges. For many types of units, such as multi fuel boilers/energy recovery units, the beta gauge will be the only option for PM CEMS. However, at the level of the new source PM limit for solid fuel boilers under Boiler MACT, the beta gauge will not be able to collect sufficient mass on its filter tape to be able to make 4 measurements per hour and satisfy the §63.7525(b)(4) requirement for continuous monitoring systems.

Based on the questions and concerns raised above, we recommend that EPA eliminate the requirement to install PM CEMS on boilers/energy recovery units.

13. We Agree that CO CEMS Should Not Be Required Under Boiler MACT or Boiler GACT, But Believe that the O₂ Monitoring Requirements Should be Re-Evaluated for Some Boilers.

In the proposed rule, EPA required CO CEMS for units sized 100 MMBtu/hr and greater. Although CO CEMS were set as the required monitoring devices, the CO limits were based on an analysis of 3-run stack test data, did not adequately consider variability, and did not exclude periods of SSM and low load. Commenters provided extensive information regarding the variability of CO emissions and the inappropriateness of setting a limit using full load stack test data and requiring units to install CO CEMS to demonstrate compliance over all operating conditions.

In the final rule, EPA removed the CO CEMS requirement and instead requires a minimum flue gas oxygen concentration operating limit and continuous O₂ monitoring. While we agree that CO CEMS are not an appropriate monitoring requirement for a CO limit based on stack test data obtained at full load conditions, we do not believe that EPA has fully considered the potential concerns with these alternative oxygen-related requirements in certain circumstances. In section 5 of these comments, we suggest an alternative CO limit with a longer averaging time for those boilers who chose to use CEMS.

The minimum oxygen and O₂ monitoring requirement are not a logical outgrowth and represent new requirements in the final Boiler MACT rule; thus petitioners were not given an opportunity to comment on their use, EPA should reconsider these new requirements as a matter of central relevance to the rule because it goes to the heart of how affected sources must demonstrate compliance with the rule.

Minimum Flue Gas Concentration Operating Limit

EPA should investigate whether the minimum oxygen requirement is effective and necessary to assure emissions are controlled to regulated levels in all instances. O₂ is an attractive measure because it is used at many boilers to track combustion efficiency which is correlated to fuel use and thus emissions. However, EPA provides no discussion of the relevance of a 12 hour averaging period in comparison to establishing the standard from one hour test data. In that regard EPA's selection of the operating limit as the lowest 1-hour average observed during CO testing is arbitrary. (Note that EPA's operating limit itself is unclear. The final rule preamble states in two places that the minimum oxygen limit is 90% of the observed performance test result (76 FR 15618, 15640) whereas the tables in Part 63 Subpart DDDDD specify the limitation as 100% of the observed minimum.)

EPA should also assess the impacts of the minimum oxygen requirement on boiler operating flexibility and efficiency and specific to boiler designs. The limit derived from a performance test period that does not include the complete mix of fuels and range of characteristics encountered over the course of an operating year would limit the operator's flexibility to deal with fuel variations. This is particularly at issue for biomass boilers which need to combust fuels of varying heating value and moisture content. First, any additional combustion air could reduce overall boiler thermal efficiency and

energy output. Higher oxygen levels result in additional flue gas which may affect performance of air pollution control equipment like ESPs that are particularly sensitive to volumetric flow rates.

O₂ Measurement Device Location

The location of the measurement device is problematic. Section 63.7525(a) of the final Boiler MACT states, "The oxygen level shall be monitored at the outlet of the boiler or process heater," preventing sources from being able to use existing O₂ trim analyzers, which imposes needless additional costs. 76 Fed. Reg. 15671. EPA should allow the use of existing O₂ analyzers, which are mounted in optimum locations.

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. 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 or process heater 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 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 was desired for continuous compliance under the Boiler MACT rule, sensing O₂ at that current location would be logical and proper from a technical perspective. However, O₂ analyzers utilized for these existing purposes are not compliance CEMS meeting PS-3 requirements relative to positioning or other QA/QC requirements. They are, however, calibrated and maintained to provide reliable and safe service for combustion unit operation.

Conversely, if O₂ was sensed prior to the stack or in the stack, that would be downstream of potential air leakage points and air preheater leakage points, thus leading to variations in readings that can impact operation and long term compliance. It must be recognized that where CO or NO_x CEMS are utilized in the stack with O₂ or CO₂ correction, that O₂ or CO₂ reading corrects for variations in excess air from the furnace as well as any air leakage or internal air heater leakage, so the impact is not of consequence from a combustion safety or direct compliance perspective. However, if it is required to actually monitor and maintain O₂ level, then the most appropriate location for sensing that O₂ level is upstream of any potential leakage points.

The most cost effective approach for utilization of O₂ CEMS would be to allow continued use of existing O₂ analyzers and use of new O₂ analyzers of appropriate design for the application to be located in optimum positions for the particular unit involved. Requiring periodic sensor calibration would be a way to ensure accurate O₂ monitoring. If new O₂ sensors are required in all cases in the breeching or stack to meet PS-3 requirements, it

would be an unjustified additional capital and ongoing O&M expense that will not provide any constructive compliance information. We request that EPA reconsider the specifics of the O₂ monitoring requirement and also provide instructions on the use of this monitoring method and for CO stack testing in common stack situations. Stack testing for CO in the common stack should be allowed without having to isolate one unit per test and causing unnecessary startups and shutdowns.

14. The Energy Assessment Should not be a Requirement in Boiler MACT or GACT and, at a Minimum, the Scope Should be Reconsidered.

EPA proposed a beyond the floor requirement of an energy assessment in the Boiler MACT and GACT rules. The energy assessment requirement remains in the final rules with some changes. We support the removal of the mandatory use of the ENERGY STAR program as a requirement in the final rule. 76 Fed. Reg. 15618. We also agree that facilities and companies that have already conducted detailed energy assessments should be exempt 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 is also supported. However, we continue to believe, as stated in our comments, 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.

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 and 63.11237 in the final MACT and GACT rules 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 and GACT rules, if the energy assessment is retained as a beyond the floor requirement, the scope should be reduced to the boiler and its auxiliaries. This element of the rule should be reconsidered because changes were made to the energy assessment requirements that were not included in the proposed rule and change the scope of the assessment.

15. We Agree that Limited Use Units Should Have Their Own Subcategory and that Work Practices are Appropriate as MACT.

In the proposed rule, EPA included 9 subcategories. Limited use boilers and process heaters were not given separate treatment than units that operate continuously. Commenters argued that limited use units should not be subject to the same compliance and testing requirements for many reasons, including the extra emissions that would happen if facilities were required to startup idle units to meet the annual

testing requirements and the fact that these units spend a good percentage of their operating time starting up and shutting down, resulting in different emission profiles than full-time use units.

In the final rule, EPA has subcategorized limited use units, so this is an appropriate reconsideration item because this subcategory (and the corresponding requirements for affected units in this subcategory) were not proposed and are not a logical outgrowth of the proposal. In addition, this issue is of central relevance to the rule because a workable approach to limited use units is needed to appropriately balance the burdens of the rule with the unique emissions characteristics of limited use boilers. Having said that, we support the creation of this subcategory due to the many reasons listed in our comments. 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. See National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters; Final Rule, 69 Fed. Reg. at 55223. This definition is equally appropriate for the current rule.

16. We Agree that it is Appropriate to set GACT for Biomass-Fired and Oil-Fired Units at Area Sources.

In the proposed Boiler GACT rule, EPA proposed to set numerical emission limits for CO for existing biomass-fired and oil-fired area source boilers and for CO and PM for new biomass-fired and oil-fired area source boilers. The final Boiler GACT rule appropriately includes work practices for existing biomass-fired and oil-fired area source boilers and includes PM limits only for new biomass-fired and oil-fired area source boilers. As we indicated in our comments on the proposed rule, we believe it is appropriate to set standards for biomass- and oil-fired boilers as GACT and not MACT.

CAA § 112(d)(5) authorizes EPA in most cases to set standards for area sources using “generally available control technologies or management practices” (*i.e.*, “GACT”) rather than “MACT.” In situations where the use of GACT is authorized (as it is here), § 112(d)(5) on its face authorizes EPA to establish “standards *or requirements* which provide for the use of generally available control technologies *or management practices*.” (Emphasis added). In other words, when setting standards based on GACT, EPA is expressly authorized to establish work practices instead of emissions limitations. Reconsideration of this issue is appropriate in order to ensure that an adequate opportunity for public comment is provided on EPA’s decision to prescribe work practices.

17. We Agree that Synthetic Area Sources Subject to Boiler GACT Should not be Required to Obtain Title V Permits.

In the proposed rule, EPA stated that synthetic area sources (those that installed controls after 1990 that resulted in facility-wide emissions below the major source HAP

thresholds) would be required to obtain a Title V permit. We submitted comments that stated these facilities should not be required to obtain a Title V permit. In the final rule, EPA has removed the requirement, but included this issue among the items to be reconsidered. For all of the reasons already included in our comments on the proposed rule, we support the removal of the requirement for area sources to obtain a Title V permit.

18. Fuel Switching Provisions for CISWI Units Should be Improved.

Petitioners provided comments on the proposed Boiler MACT and CISWI rules on the lack of a provision to allow units to switch back and forth between Boiler MACT and CISWI based on whether they are burning fuel and waste. In the final rule, EPA included a mechanism for sources to move between the two rules, but sources must wait 6 months after cessation of solid waste burning to move back under Boiler MACT. As this is a new requirement in the final rule, it is appropriate for EPA to reconsider it. EPA arbitrarily chose 6 months. With the extensive monitoring and testing required under both rules, facilities should 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.

Appendix A. Errors in the Determination of RDLs to Set Boiler MACT and CISWI PCDD/F Limits

by Arun V. Someshwar and Ashok K. Jain
National Council for Air and Stream Improvement (NCASI)

Executive Summary

In setting the boiler MACT standards, EPA has stated that the emission limit should not be set below the capability of the applicable test method which is defined as its limit of quantitation. Source testing professionals agree that this information is best obtained by conducting simultaneous emission tests with multiple sampling trains operated by different teams with analysis performed at different laboratories. However, in setting the PCDD/F standards, EPA has erroneously used the detection capabilities of best performing laboratories to determine method quantitation limits and has promulgated standards which are orders of magnitude below the quantitation limits of PCDD/F in biomass boiler emissions. We recommend that for Boiler MACT, EPA should set work practice standards for PCDD/F since most of the measurements were well below the quantitation limit of EPA Method 23. Alternatively, EPA must reanalyze its Boiler MACT data and set much higher PCDD/F limits. Under the CISWI rule, if work practice standards are not allowed under Section 129, EPA must reanalyze its ERU PCDD/F data and set much higher PCDD/F limits.

EPA Procedure for Setting the PCDD/F Standards

In order to establish the PCDD/F emission limit for biomass stoker boilers, EPA chose from its database only those stokers that burned at least 90% biomass. This resulted in only nine boilers with PCDD/F emissions data. Assuming all NDs at their DLs, EPA then determined the top 12% with the lowest TEQs to be represented by 2 boilers, namely the Georgia Pacific, Madison, GA and Boralex Stratton Energy, Stratton, ME boilers, each with 3 runs. Table 1 shows the detailed isomer-specific data and the WHO-TEF/2005 TEQs for the six runs on these two boilers. The mean and 99% UPL value for the six runs was 1.64E-03 and 3.82E-03 ng/dscm @ 7% O₂, respectively.

Table 1. PCDD/F Emissions For 2 Biomass Stokers in Top 12%

Pollutant Name	PCDD/PCDFs in ng/dscm @ 7% O ₂					
	Georgia Pacific, Madison, GA			Boralex Stratton Energy, ME		
	Run 1	Run 2	Run 3	Run 1	Run 2	Run 3
1,2,3,4,6,7,8 HpCDD	1.55E-03	8.99E-04	6.82E-04	4.31E-03	5.39E-03	1.83E-03
1,2,3,4,6,7,8 HpCDF	2.79E-03	1.88E-03	1.69E-03	3.66E-03	8.10E-03	1.64E-04
1,2,3,4,7,8 HxCDD	6.32E-04	5.72E-04	5.03E-04		4.21E-05	
1,2,3,4,7,8 HxCDF	1.10E-03	5.62E-04	2.98E-04	4.63E-04	1.76E-03	
1,2,3,4,7,8,9 HpCDF	5.01E-04	4.10E-04	6.18E-04	8.14E-05	1.28E-03	1.99E-04
1,2,3,6,7,8 HxCDD	6.11E-04	5.50E-04	5.13E-04		4.35E-04	
1,2,3,6,7,8 HxCDF	7.49E-04	2.10E-04	2.79E-04	5.76E-04	1.81E-03	
1,2,3,7,8 PeCDD	6.55E-04	3.12E-04	5.62E-04		4.24E-04	1.31E-04
1,2,3,7,8 PeCDF	8.14E-04	7.07E-04	5.99E-04	4.89E-04	1.41E-03	
1,2,3,7,8,9 HxCDD	6.65E-04	6.21E-04	5.45E-04			

1,2,3,7,8,9 HxCDF	5.17E-04	2.70E-04	3.52E-04		1.43E-04	
2,3,4,6,7,8 HxCDF	5.87E-04	2.19E-04	2.96E-04	3.76E-04	2.15E-03	
2,3,4,7,8 PeCDF	6.97E-04	6.70E-04	5.91E-04	6.25E-04	1.82E-03	3.97E-05
2,3,7,8-TCDD	1.69E-03	4.57E-04	3.30E-04		1.10E-04	6.32E-04
2,3,7,8-TCDF	8.85E-04	5.18E-04	4.32E-04	3.17E-03	2.12E-03	7.52E-04
Total OCDD	4.96E-03	3.95E-03	3.13E-03	1.83E-02	1.71E-02	7.44E-03
Total OCDF	3.39E-03	2.37E-03	1.71E-03	4.66E-03	8.31E-03	7.94E-04
TEQs using ND=DL	3.21E-03	1.38E-03	1.44E-03	7.48E-04	2.12E-03	8.74E-04

shaded entries are non-detects shown at the detection limit

On pages 14 and 15 of the ERG memo¹, under “*Measurement Detection Level Variability*”, a procedure is laid out whereby the calculated UPL is compared to a computed value that was developed to account for the effect of measurement imprecision associated with a database that includes method detection level data. For each test run, a detection level (DL) is estimated (in TEQ units) by replacing each congener value by the average of all the “flagged” values (BDL or DLL) for that run and then recalculating the run TEQ. Table 2 shows the result of these calculations for the six runs shown in Table 1. The maximum DL value is estimated to be 1.92E-03 ng/dscm @ 7% O₂. The EPA procedure then stipulates that the maximum DL cannot be greater than the mean of the pollutant emissions values from the best performers and this largest value becomes the RDL for each pollutant emissions dataset. The larger of the 3 x RDL value and the computed floor value or emissions limit (e.g., the 99 percent confidence UPL) becomes the limit. Thus, since the mean (1.64E-03) is less than the maximum DL (1.92E-03), the 3 x RDL value for biomass stokers becomes 3 x 1.64E-03 or 4.92E-03 ng/dscm @ 7% O₂. Since this value is higher than the calculated floor derived from the UPL calculations (3.82E-03), it becomes the basis for the floor (Note this value compares favorably with the EPA derived limit of 5.00E-03 ng/dscm @ 7% O₂).

Table 2. Estimation of Detection Levels For Each Run - 2 Biomass Stokers in Top 12%

Pollutant Name	PCDD/PCDFs in ng/dscm @ 7% O ₂					
	Georgia Pacific, Madison, GA			Boralex Stratton Energy, ME ¹		
	Run 1	Run 2	Run 3	Run 1	Run 2	Run 3
1,2,3,4,6,7,8 HpCDD	6.08E-04	4.60E-04	5.45E-04			
1,2,3,4,6,7,8 HpCDF	6.08E-04	4.60E-04	5.45E-04			
1,2,3,4,7,8 HxCDD	6.08E-04	4.60E-04	5.45E-04			
1,2,3,4,7,8 HxCDF	6.08E-04	4.60E-04	5.45E-04			
1,2,3,4,7,8,9 HpCDF	6.08E-04	4.60E-04	5.45E-04			
1,2,3,6,7,8 HxCDD	6.08E-04	4.60E-04	5.45E-04			
1,2,3,6,7,8 HxCDF	6.08E-04	4.60E-04	5.45E-04			
1,2,3,7,8 PeCDD	6.08E-04	4.60E-04	5.45E-04			
1,2,3,7,8 PeCDF	6.08E-04	4.60E-04	5.45E-04			
1,2,3,7,8,9 HxCDD	6.08E-04	4.60E-04	5.45E-04			
1,2,3,7,8,9 HxCDF	6.08E-04	4.60E-04	5.45E-04			
2,3,4,6,7,8 HxCDF	6.08E-04	4.60E-04	5.45E-04			
2,3,4,7,8 PeCDF	6.08E-04	4.60E-04	5.45E-04			
2,3,7,8-TCDD	6.08E-04	4.60E-04	5.45E-04			
2,3,7,8-TCDF	6.08E-04	4.60E-04	5.45E-04			
Total OCDD	6.08E-04	4.60E-04	5.45E-04			
Total OCDF	6.08E-04	4.60E-04	5.45E-04			
DL (in TEQs)	1.92E-03	1.45E-03	1.72E-03	0.00E+00	0.00E+00	0.00E+00

¹no entries for the Boralex unit since the DLs for all NDs were unavailable in the original report;

Differences in EPA's Procedures for Establishing Biomass Stoker PCDD/F Limits

There are a number of major deficiencies in EPA's methodology for establishing biomass stoker PCDD/F emission limits:

- (1) As seen in Tables 1 and 2, no analytical detection limit data were available for the Boralex Stratton Energy boiler. Thus EPA treated those values as zero in selecting that boiler as a best performer. This error biased the results low.
- (2) EPA's methodology for determining method quantitation limits is not valid, as described below.

In its September 18, 2009 guidance to sources obligated to perform dioxin/furan testing in response to the 2009 ICR, EPA directed sources to "calculate the in-stack emissions rate for any analytical measurement below detection level using the relevant detection level as the "real value," in direct conflict with the Method 23 requirement. When this approach was used to establish PCDD/F emissions, because most of the congeners were present below the method detection limit, the sources with the lowest analytical method detection limit became the best performers. Thus, by default, the lowest reported analytical detection limits became the reference method detection limit (RDL) in EPA's calculations, which then became the basis for determining the quantitation limit (determined to be three times the RDL).

In using the above approach, EPA seems to have assigned as method detection limits the lowest analytical detection limit values obtained at one or two laboratories for one or two sets of data. As NCASI stated in its comments on the boiler MACT proposal (U.S. EPA Docket EPA-HQ-OAR-2002-0058), EPA Method 23 consists of extracting a known volume of the sample from the stack to capture the target pollutant on a filter, in a capture solution, or combination of both, processing the collected samples, and analyzing the samples. Each of these three steps can introduce random errors to the final measurement. For example, when a stack sample is collected, due to stratification in the stack, the sample may not represent the true average concentration of the pollutant. Similarly, some contamination may be introduced in a sample during its processing. For example, some particulate matter may be left when samples are transferred from one container to another. Or, some PM may fall into the sample container during its handling. Finally, during analysis, the instrument calibration may not have an r^2 value equal to 1.0 or there may be matrix interference, either of which affects the analyst's ability to accurately identify and quantify an instrument reading.

The above examples of potential sources of random errors associated with EPA test Method 23 are not unique to this method. All measurements have errors associated with them. These errors consist of systematic errors, if the method is biased, and random errors. Even in the absence of any systematic errors, random errors cause replicate measurements to vary from run to run, although the average of such random

errors is zero when the number of replicates is high. In general, the magnitude of the random error decreases as a fraction of the measured value as the value of the measured parameter increases. In practice, when the measured value of a parameter is much higher than the potential for random error, there is a high degree of confidence in the measured value obtained from a single or a few runs. However, as the measured value decreases, the potential contribution of the random error to the measured value increases, thus decreasing the confidence level in the measured value from a single or a few runs until the point where the measured value cannot be distinguished from the random error.

Analytical chemists have for a long time been concerned about their ability to determine whether or not an analyte is present in a sample and, if it is present, its true level. This has given rise to two important concepts: limit of detection and limit of quantitation. In general terms the detection limit of an analytical method is defined as the lowest concentration that can be distinguished from the blank at a defined level of statistical significance. The quantitation limit for a method is defined as the smallest concentration of the analyte which can be measured where the accuracy achieves the objectives of the measurement.

A number of methods have been proposed for determining analytical method detection and quantitation limits (Coleman et al. 1997, Corley 2003, Currie 1999, Voigtman 2008). In 2004, EPA conducted a detailed review of analytical method detection and quantitation approaches (EPA 2004). In its simplest form, the detection limit of an analytical method is determined by conducting 7 replicate analyses of a very low level sample and multiplying the resulting standard deviation by 3.14. The quantitation limit, which is also defined as the minimum level of the test method, is then calculated by multiplying the detection limit by 3.18 (EPA 2004, pp. 5-35).

While the above methods for determining the detection and quantitation limits are adequate for the analysis component of test methods, as described earlier, source emission test methods have two other components, namely sampling and sample processing, prior to sample analysis. Thus, any procedure for determining the detection and quantitation limits of source emission test methods needs to include procedures that would account for the random errors associated with sampling and sample processing in addition to evaluating random errors associated with sample analysis.

EPA has been well aware of the issues related to method detection and quantitation limits for many years, as reflected in EPA's appointment in 2005 of a federal advisory committee on detection and quantitation approaches and their uses in the Clean Water Act Program (Federal Register 2005) and issuing a 2005 memorandum regarding effluent limits which states: "The NPDES permit should state that any sample analyzed in accordance with a method having appropriate method detection limit (MDL) and minimum level (ML) and found to be below the ML will be considered in compliance with the permit limits unless other monitoring information indicates a violation." (EPA 2005)

To establish the analytical method quantitation limits, a majority of EPA's National Advisory Committee recommended that a minimum of 6 to 7 laboratories be used to set

National Quantitation limits and after applying an appropriate outlier test, the quantitation limit should be set at the upper 95% confidence limit for normally distributed data or 95th percentile of the laboratory quantitation limit data, if data are non-normally distributed. To accomplish this, NCASI reassembled and reanalyzed all the PCDD/F emissions data in the industrial boiler MACT database and attempted to establish the 95th percentile values of detection limits for each of the 17 PCDD/F isomers. The detail boiler-specific data are provided as an attachment to this document in excel format. Before these percentile values were determined, the entire body of data comprising the detection limits for each non-detect isomer was checked for suspected “outliers” using the Rosner’s test. This test can be used to detect up to 10 outliers for sample sizes of 25 or more. However, the suspected outliers at the 99% confidence interval were discarded from the dataset only after the data were plotted graphically and the outliers confirmed by “visual observation”. Table 3 provides the 95th percentile values of the detection limits for each of the 17 PCDD/F isomers corresponding to all the PCDD/F emissions data in EPA’s industrial boiler emissions database. Data for a total of 110 boilers were included in this analysis, of which 57 were biomass units (>10% biomass fired), 9 were CISWI units, 14 were Gas 1 units, 4 were Gas 2 units, 25 were coal units (>90% coal), and 1 was an oil unit.

Results of the Current NCASI Analysis

Table 4 summarizes the quantitation limits for the 17 isomers using the 95th percentile values of detection limits shown in Table 1 where each QL is taken at 3 x the DL. Also shown is the QL in WHO-TEF/2005 TEQ units. The data show that using the 95th percentile values for the QLs, the floors for PCDD/F emissions from industrial boilers cannot be less than 0.106 ng/dscm at 7% O₂ in WHO-TEF/2005 TEQs. For each of the 17 isomers, Table 5 shows the fractions of all results or observations in the entire Boiler MACT PCDD/F database that was below the 95th percentile quantitation limits as shown in Table 4. It is seen that on average 94.6% of all data were below the method quantitation levels when using the 95th percentile values for the QLs. Thus, a very large fraction of all the data was always below the respective QL for the isomer.

Table 3. Summary of Detection Limit Statistics for All Non-Detects in the Boiler MACT PCDD/F Database, ng/dscm at 7% O₂

Congener	N ¹	Min.	Max.	95th %ile ²
1,2,3,4,6,7,8	53	1.68E-04	1.60E-02	1.60E-02
1,2,3,4,6,7,8 HpCDF	108	1.80E-04	2.50E-02	1.60E-02
1,2,3,4,7,8 HxCDD	162	5.65E-05	1.65E-02	1.22E-02
1,2,3,4,7,8 HxCDF	87	4.66E-05	1.60E-02	1.35E-02
1,2,3,4,7,8,9 HpCDF	189	4.63E-06	1.60E-02	1.11E-02
1,2,3,6,7,8 HxCDD	134	4.99E-05	1.61E-02	1.28E-02
1,2,3,6,7,8 HxCDF	100	4.29E-05	1.60E-02	1.28E-02
1,2,3,7,8 PeCDD	168	1.75E-04	1.60E-02	1.19E-02
1,2,3,7,8 PeCDF	113	2.56E-05	1.60E-02	1.28E-02
1,2,3,7,8,9 HxCDD	153	8.04E-04	1.80E-02	1.28E-02
1,2,3,7,8,9 HxCDF	181	0.00E+00	1.60E-02	1.14E-02
2,3,4,6,7,8 HxCDF	126	4.85E-05	1.60E-02	1.22E-02
2,3,4,7,8 PeCDF	110	2.00E-04	1.62E-02	1.35E-02
2,3,7,8-TCDD	210	0.00E+00	1.60E-02	8.72E-03
2,3,7,8-TCDF	81	2.95E-06	1.17E-02	1.00E-02
Total OCDD	41	5.50E-04	3.20E-02	3.20E-02
Total OCDF	84	2.02E-04	2.02E-02	1.61E-02
In WHO-TEF/2005 TEQs				3.53E-02

¹No. of Observations; ²Detection Limit

Table 4. Summary of Quantitation Limits For Each PCDD/F Isomer Based on the 95th Percentile Detection Limits Determined in Table 3, ng/dscm at 7% O₂

Congener	N ¹	95th %ile ²
1,2,3,4,6,7,8 HpCDD	53	4.80E-02
1,2,3,4,6,7,8 HpCDF	108	4.80E-02
1,2,3,4,7,8 HxCDD	162	3.66E-02
1,2,3,4,7,8 HxCDF	87	4.05E-02
1,2,3,4,7,8,9 HpCDF	189	3.33E-02
1,2,3,6,7,8 HxCDD	134	3.84E-02
1,2,3,6,7,8 HxCDF	100	3.84E-02
1,2,3,7,8 PeCDD	168	3.57E-02
1,2,3,7,8 PeCDF	113	3.84E-02
1,2,3,7,8,9 HxCDD	153	3.84E-02
1,2,3,7,8,9 HxCDF	181	3.42E-02
2,3,4,6,7,8 HxCDF	126	3.66E-02
2,3,4,7,8 PeCDF	110	4.05E-02
2,3,7,8-TCDD	210	2.62E-02
2,3,7,8-TCDF	81	3.00E-02
Total OCDD	41	9.60E-02
Total OCDF	84	4.84E-02
In WHO-TEF/2005 TEQs		1.06E-01

¹No. of Observations; ²Quantitation Limit = 3 X Detection Limit

Table 5. Fraction of Observations in the Entire Boiler MACT PCDD/F Database Below the 95th Percentile Quantitation Limits As Shown in Table 4

Congener	N ¹	95th %ile ²	95th %ile ³
1,2,3,4,6,7,8 HpCDD	327	303	92.7%
1,2,3,4,6,7,8 HpCDF	324	303	93.5%
1,2,3,4,7,8 HxCDD	327	313	95.7%
1,2,3,4,7,8 HxCDF	327	312	95.4%
1,2,3,4,7,8,9 HpCDF	327	318	97.2%
1,2,3,6,7,8 HxCDD	327	308	94.2%
1,2,3,6,7,8 HxCDF	327	313	95.7%
1,2,3,7,8 PeCDD	327	316	96.6%
1,2,3,7,8 PeCDF	327	311	95.1%
1,2,3,7,8,9 HxCDD	327	315	96.3%
1,2,3,7,8,9 HxCDF	327	315	96.3%
2,3,4,6,7,8 HxCDF	327	310	94.8%
2,3,4,7,8 PeCDF	327	303	92.7%
2,3,7,8-TCDD	327	317	96.9%
2,3,7,8-TCDF	327	292	89.3%
Total OCDD	322	295	91.6%
Total OCDF	320	309	96.6%
			94.6%

¹Total number of valid observations excluding outliers; ²number below QL in Table 4; ³% of data < QL

It should be noted here that the above analysis is only based on the analytical method quantitation limit and does not include random errors associated with sample collection and recovery of the samples. These activities are expected to increase the quantitation limit of Method 23.

Appendix B. Additional CO Data Analyses

1. Analysis of CO CEMS Data for Two Biomass Boiler Top Performers

The lone boiler in the top 12% biomass FBC performer list with a CO CEMS already installed, which was also the best performer in its category and thus the basis for setting limits for new boilers (both based on a short term 3 run data set), is the biomass fluidized bed combustor (FBC) at Temple-Inland in Rome, GA. In addition to the data for the 3-run test, Temple-Inland had also submitted to EPA 30 days of CO CEMS data for the period between 7/1/08 and 7/30/08 (Docket ID No. EPA-HQ-OAR-2002-0058). It appears that EPA has not used these data in setting the floor for biomass FBCs (existing and new). Temple-Inland also submitted to EPA a plot of the 30-day rolling average (CO CEM data) for this boiler that covered a 12-month period (7/7/09 to 7/7/10). NCASI obtained the detailed hourly average data for this 12-month duration and analyzed them as described in this document. NCASI also recently obtained 4 months of CO CEMS data from an engineering study on a biomass stoker unit (Georgia Pacific in New Augusta, MS) that was also considered to be among the top 12% performers for the existing biomass stoker category. This document analyses these two sets of data and shows how alternate 24-hour average CO limits will need to be developed for existing and new industrial boilers that are already equipped with CO CEMS.

Boiler in Top 12% Biomass Stoker Category With CO CEMS

The Boiler MACT CO limit for existing biomass stokers is 490 ppm @ 3% O₂. The Georgia Pacific, New Augusta, MS mill biomass stoker was among the twelve boilers considered to be among the best performers for CO emissions for the biomass stoker category. A value of 130 ppm @ 3% O₂, the average of three one hour duration CO runs (90, 90 and 210.2 ppm), was used to represent this boiler. This mill recently conducted a 4 month-long CO emissions study on this same boiler using a rented CO CEMS (Oct. 1, 2010 to Jan. 31, 2011). Detail one-minute average data were available for analysis. Twenty-four hour average blocks (daily) were developed from these detail data (122 days) after eliminating a small amount of data that clearly corresponded to startup and shutdown conditions (0.4%).

Table 1 provides a summary of the statistics obtained to derive the 99.9% UPL value of the 24-hour average data (122 points) for this boiler. The 99.9% UPL value is seen to be 645 ppm @ 3% O₂ assuming the data were normally distributed, but since the data were not normally distributed the 99.9% UPL value of the log-normally transformed data was estimated and it was 804 ppm @ 3% O₂.

Figure 1 shows a plot of the 24-hour average stack CO concentrations over the 4 month period. The CO concentrations are shown ordered from the lowest to the highest levels, ranging from 143 to 704 ppm.

Table 1. Statistics for Daily Averages From CO CEM Data at the GP New Augusta Biomass Stoker

mean (X) 337.9	sd (X) 96.7	is dist. normal ? N	TINV 3.15895	99.9% UPL; m = 1¹ 645
mean (lnX) 5.8	sd (lnX) 0.3	is dist. normal ? Y	TINV 3.15895	99.9% UPL; m = 1 6.7
			UPL of X =	804

¹ 99.9% UPL = [mean + stdev * Tinv * (1/122+1)^{0.5}]; ² data was not normal at the 5% Significance Level, thus the statistics for the log-normalized data set are also presented;

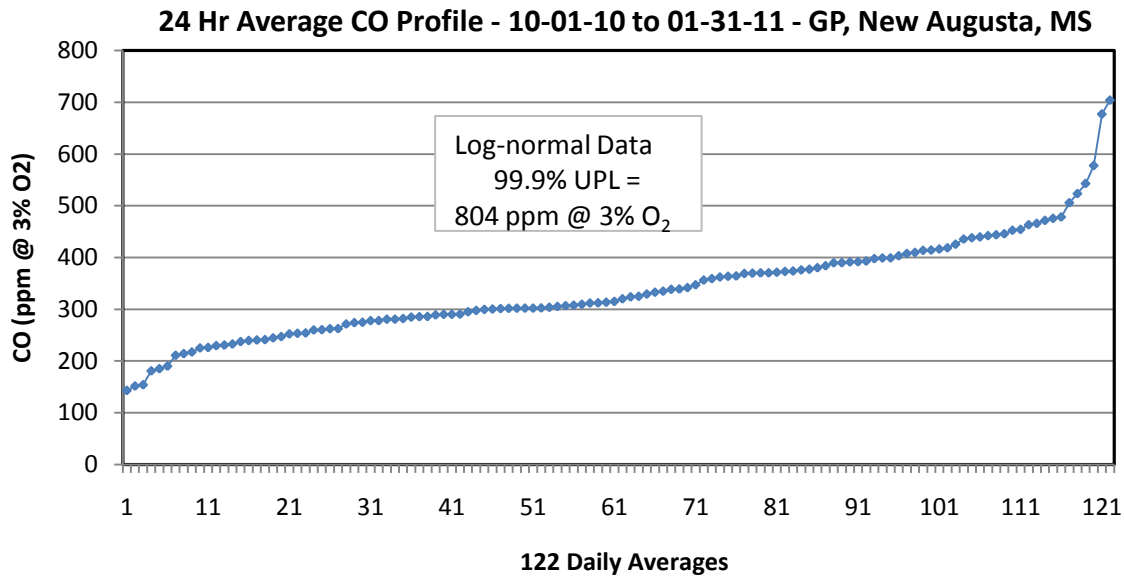


Figure 1. 24 Hour Average CO CEMS Data – GP, New Augusta, MS – 10-01-10 to 01-31-11

Table 2 shows that the CO limit of 804 ppm @ 3% O₂ would never have been exceeded for this boiler over the 4-month study period.

Table 2. Exceedances Based on Analyzing Daily Average Data at the GP, New Augusta, Biomass Stoker

If Limit at	# of Days Exceeding Limit	Percent of Time Limit Exceeded
803.8 ppm @ 3% O ₂	0	0.0%

Boiler in New Biomass FBC Category With CO CEMS

The Boiler MACT CO limit for new biomass fluidized bed combustors is 260 ppm @ 3% O₂. This limit was based on a set of three runs at the best performing biomass-fired FBC unit at Temple-Inland in Rome, GA (136.3, 60.9 and 99.2 ppm @ 3% O₂, avg = 98.8). However, this boiler is equipped with a CO CEMS. As previously mentioned, Temple-Inland had submitted a limited amount of CO CEMS data to EPA and a plot of the 30-day rolling average (CO CEM data) for the period between 7/7/09 and 7/7/10.

These data were not considered by EPA in setting limits for biomass FBCs (new or existing). NCASI obtained the detail 24-hour average data for this year-long duration directly from the mill. Just as for the GP New Augusta boiler, twenty-four hour average blocks (daily) were developed from these detail data (365 days) after eliminating a small amount of data that clearly corresponded to startup-shutdown conditions (0.8%). Table 3 provides a summary of the statistics obtained to derive the 99.9% UPL value of the 24-hour average data (360 points) for this boiler. The 99.9% UPL value is seen to be 318 ppm assuming the data were normally distributed, but since the data were not normally distributed the 99.9% UPL value of the log-normally transformed data was estimated (390 ppm).

Table 3. Statistics for Daily Averages From CO CEM Data at the T-I Rome Biomass FBC

mean (X) 114.0	sd (X) 65.3	is dist. normal ? N¹	TINV 3.11309	99.9% UPL; m = 1¹ 318
mean (lnX) 4.6	sd (lnX) 0.4	is dist. normal ? N	TINV 3.11309	99.9% UPL; m = 1 6.0
			UPL of X =	390

¹ 99.9% UPL = [mean + stdev * tinv * (1/360+1)^{0.5}]; ² data was not normal at the 5% Significance Level, thus the statistics for the log-normalized data set are also shown;

Figure 2 shows a plot of the 24-hour average stack CO concentrations over the 12 month period. The CO concentrations are shown ordered from the lowest to the highest levels, ranging from 41 to 689 ppm.

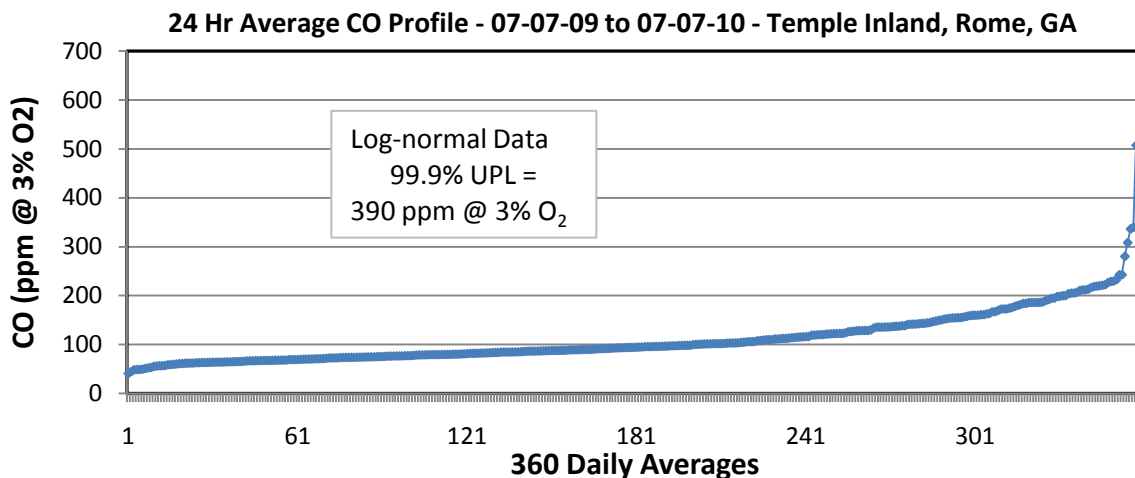


Figure 2. 24 Hour Average CO CEMS Data – Temple-Inland Rome, GA – 07-07-09 - 07-07-10

Table 4 shows that the CO limit of 390 ppm @ 3% O₂ would have been exceeded for 3 days or 0.8 percent of the study period.

Table 4. Exceedances Based on Analyzing Daily Average Data at the T-I Rome, Biomass FBC

If Limit at	# of Days Exceeding Limit	Percent of Time Exceeded Limit
390 ppm @ 3% O ₂	3	0.8%

Conclusion

Based on a limited amount of CO CEMS data presented here, it is seen that the 24-hour average limit for boilers already equipped with CO CEMS would have to be higher than those derived from short term typically one or two sets of 3 run tests. Since the CO CEMS would always be in operation, natural fluctuations in the boiler's CO emissions over a long period of time due to fuel variability and other factors would dictate that a higher limit based on long term CO CEMS data analysis is warranted for such boilers. Further, it should be recognized that a 99.9% UPL does not mean the limit would never be exceeded for an actual data set. As is seen for the Rome boiler, the 99.9% UPL was exceeded for 0.8% of the 360 24-hour periods. Thus, if any 24-hour standards are set, they should include a 1% exceedance allowance. Finally, since boilers are exempt from meeting the CO limit during periods of startup and shutdown, these periods will need to be clearly defined relative to the boiler's operations.

2. CO Limits For Existing and New Biomass Stokers and FBCs Should Be Recalculated By Including Longer Duration CO CEMS Data For Boilers Already Determined To Be Best Performing

The recently promulgated Boiler MACT CO limits for existing biomass stokers and biomass fluidized bed combustors (FBCs) are based on determining the 99.9% UPL value of a limited number of short term 3-run test averages for 12 and 5 "best performing" boilers, respectively. Sixteen sets of 3-run test averages were available for the 12 best performing biomass stokers, whereas only five sets were available for the 5 best performing biomass FBCs. The limits for new biomass stokers and FBCs are both based on considering just three runs from a single test at the best performing boiler.

It is generally well known that CO emissions from biomass combustion in boilers are highly variable over longer time durations, even when firing more or less the same biomass fuel. Seasonal variability in the quality of the biomass fuel fired may be partly responsible. Moreover, although the short term 3-run test averages were considered for analysis strictly only when the boiler was burning >90% biomass, during a given year a biomass boiler as presently categorized can burn other fuels (gas, coal, oil, etc.) up to 90% of its total heat input. Thus, unless data that sufficiently capture the variability of CO emissions in such "best performing" boilers are also included in the analysis for determining the floors, the limits as currently derived would not be reflective of the variability in CO emissions from these boilers.

The short term 3-run tests were typically carried out using a certified CO CEMS. If longer term CO CEMS data were available on these same best performing boilers,

these would be very helpful in addressing the variability in CO emissions from such best performing units. To demonstrate this fact, two sets of long-term CO CEMS data corresponding to one boiler each in the biomass stoker and biomass FBC category are presented and analyzed in this document. NCASI recently obtained 4 months of one minute average CO CEMS data as a part of an engineering study conducted on the Georgia Pacific, New Augusta, MS biomass stoker unit. This boiler already belongs to the group of 12 stoker units that has been identified by EPA as the top 12% “best performers”, based on which the current limit of 490 ppm @ 3% O₂ was derived. NCASI also analyzed one year’s duration (7/7/09 and 7/7/10) of hourly average CO CEMS data for the biomass FBC unit at Temple-Inland, Rome, GA. In addition to the data for a 3 one hour-run test, which caused this boiler to be a best performer in its category for both existing and new FBCs, Temple-Inland had also submitted to EPA 30 days of CO CEMS data (7/1 to 7/30/08) and a plot of the 30-day rolling average (CO CEM data) for the period between 7/7/09 and 7/7/10. However, the 30-day CO CEMS data appear not to have been considered by EPA in setting limits for biomass FBCs, new or existing.

The analysis presented here looks at the impact on the 99.9% UPL value (floor or limit) when the 3 hour-average blocks of CO CEMS data from these two boilers are combined with the more limited number of 3-run test averages that were used to determine the floors for existing biomass stokers and FBC units. It also looks at the impact on the 99.9% UPL value for new biomass FBCs based on the CO CEMS data for the Temple-Inland, Rome, GA unit since this unit was also the best performer in its category. Further, it is suggested that just as for the new biomass FBC category, the limits for the new biomass stoker category should be revisited after generating additional CO CEMS data on the Louisiana Pacific, Sagola, MI biomass stoker, the best performer in the biomass stoker category.

Recalculated Limit For Existing Biomass Stokers

The current Boiler MACT CO limit for existing biomass stokers is 490 ppm @ 3% O₂. This limit was arrived at by analyzing the short term 3 test run averages corresponding to 12 biomass stokers that burned >90% biomass “during the tests”. EPA’s protocol for determining the floor requires that once the top candidates in the floor are identified, then all valid data corresponding to the boilers in this floor that were otherwise not included in determining the best performers need to be included in the UPL analysis to determine the floor. This was no doubt put in so as to include the impact of the variability within a boiler’s own emissions over longer periods of time.

A 4 month-long CO emissions study was conducted on the MSGPNewAugusta boiler using a rented CO CEMS (Oct. 1, 2010 to Jan. 31, 2011). The detail one-minute average data are available for analysis. Nine hundred and sixty (960) three-hour average blocks were developed from these detail data (122 days) after eliminating a small amount of data that clearly corresponded to startup/shutdown/malfunction (SSM) conditions (~0.4%). EPA had already considered sixteen 3-hour averages corresponding to 12 boilers in estimating the 99.9% UPL value (floor) for CO emissions for biomass stokers. Table 1 provides a summary of the statistics obtained when all

976 3-hour average data points (960 + 16) are used to derive the 99.9% UPL value. The 99.9% UPL value is estimated at 736 ppm @ 3% O₂ assuming the data were normally distributed, but since the data were not normally distributed, the 99.9% UPL value of the log-normally transformed data was estimated and it was 1068 ppm @ 3% O₂.

Table 1. Recalculated Statistics for the CO Floor - Existing Biomass Stokers

mean (X) 336.6	sd (X) 128.7	is dist. normal ? N²	TINV 3.0986	99.9% UPL; m = 1¹ 736
mean (lnX) 5.7	sd (lnX) 0.4	is dist. normal ? N	TINV 3.0986	99.9% UPL; m = 1 7.0
			UPL of X =	1068

¹ 99.9% UPL = [mean + stdev *Tinv * (1/976+1)^{0.5}]; ² data was not normal at the 5% Significance Level, thus the statistics for the log-normalized data set are also presented;

Recalculated Limit For Existing Biomass FBCs

The current Boiler MACT CO limit for existing biomass fluidized bed combustors is 430 ppm @ 3% O₂ and it was arrived at by analyzing the short term 3-run test averages corresponding to 5 biomass FBCs that burned >90% biomass “during the tests”. As previously mentioned, the FBC unit at Temple-Inland, Rome, GA was included in this list of the 5 best performing FBCs based solely on data submitted for a single 3-run test. NCASI obtained detail hourly-average data for this boiler for the period between 7/7/09 and 7/7/10. Two thousand seven hundred and ninety three (2793) three-hour average blocks were developed from these detail data (365 days) after eliminating a small amount of data that clearly corresponded to startup or shutdown conditions (~0.8%). EPA had already considered five 3-hour averages corresponding to 5 boilers (including the Rome boiler) in estimating the 99.9% UPL value (floor) for CO emissions from biomass FBCs. Table 2 provides a summary of the statistics obtained when all 2798 3-hour average data points (2793 + 5) are used to derive the 99.9% UPL value. The 99.9% UPL value is estimated at 405 ppm @ 3% O₂ assuming the data were normally distributed, but since the data were not normally distributed, the 99.9% UPL value of the log-normally transformed data was estimated and it was 474 ppm @ 3% O₂.

Table 2. Recalculated Statistics for the CO Floor - Existing Biomass FBCs

mean (X) 113.7	sd (X) 94.2	is dist. normal ? N²	TINV 3.0931	99.9% UPL; m = 1¹ 405
mean (lnX) 4.6	sd (lnX) 0.5	is dist. normal ? N	TINV 3.0931	99.9% UPL; m = 1 6.2
			UPL of X =	474

¹ 99.9% UPL = [mean + stdev *Tinv * (1/2798+1)^{0.5}]; ² data was not normal at the 5% Significance Level, thus the statistics for the log-normalized data set are also shown;

Recalculated Limit For New Biomass Stokers

The current Boiler MACT CO limit for new biomass stokers is 160 ppm @ 3% O₂ and it was arrived at by analyzing data from 3 runs at the best performing biomass stoker at the Louisiana Pacific, Sagola, MI mill (51.8, 56.1 and 96.0 ppm @ 3% O₂, avg = 68.0). Just as for the new biomass FBC unit discussed below, if additional CO CEMS data were available for this boiler, an analysis of additional 3 hour average CO blocks would have shown that the CO limit should have been higher, correctly reflecting the variability in CO emissions in even the best performing biomass stoker unit.

Recalculated Limit For New Biomass FBCs

The biomass FBC unit at Temple-Inland, Rome, GA was also the best performing FBC unit relative to CO emissions. The Boiler MACT CO limit for new biomass FBCs is 260 ppm @ 3% O₂. This limit was based on a set of three runs at the Temple-Inland, Rome, GA FBC unit (136.3, 60.9 and 99.2 ppm @ 3% O₂, avg = 98.8). As previously indicated, 2793 three-hour average blocks were developed from the detail CO CEMS data (365 days) on this boiler after eliminating a small amount of data that clearly corresponded to startup or shutdown conditions (~0.8%). Table 3 provides a summary of the statistics obtained when all 2794 3-hour average data points (2793 + 1) are used to derive the 99.9% UPL value. The 99.9% UPL value is estimated at 405 ppm @ 3% O₂ assuming the data were normally distributed, but since the data were not normally distributed, the 99.9% UPL value of the log-normally transformed data was estimated and it was 473 ppm @ 3% O₂.

Table 3. Recalculated Statistics for the CO Floor - New Biomass FBCs

mean (X)	sd (X)	is dist. normal ?	TINV	99.9% UPL; m = 1 ¹
113.7	94.2	N ¹	3.093154	405
mean (lnX)	sd (lnX)	is dist. normal ?	TINV	99.9% UPL; m = 1
4.6	0.5	N	3.093153	6.2
			UPL of X =	473

¹ 99.9% UPL = [mean + stdev * Tinv * (1/2794+1)^{0.5}]; ² data was not normal at the 5% Significance Level, thus the statistics for the log-normalized data set are also shown;

Conclusion

If the additional 960 CO emission data points representing 3 hour averages for the GP, New Augusta, MS biomass stoker unit and 2793 CO emission data points representing 3 hour averages for the Temple-Inland, Rome, GA biomass FBC unit are included in the UPL determinations, the floor for existing biomass stokers and FBCs jump from the current 490 ppm and 430 ppm @ 3% O₂ to 1068 ppm and 474 ppm @ 3% O₂, respectively. Using the same 2793 CO emission data points representing 3 hour averages for the Temple-Inland, Rome, GA biomass FBC unit, the floor for new biomass FBCs jump from the current 260 ppm @ 3% O₂ to 473 ppm @ 3% O₂.

This analysis of longer term CO CEMS data on boilers already considered to be among the best performing in their respective categories clearly suggests that a few short tests lasting 3 hours do not capture the variability in boiler CO emissions. Biomass boiler CO emissions are greatly affected by fuel moisture content and boiler load fluctuations. Consequently, EPA must consider long-term data in setting the CO emission limits.