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COMMENTS OF THE COUNCIL OF INDUSTRIAL BOILER OWNERS
on
EPA Proposed Rule
National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters
75 Fed. Reg. 32006, EPA–HQ–OAR–2002–0058
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The Council of Industrial Boiler Owners (CIBO or The Council) appreciates the opportunity to comment on EPA's June 4, 2010 proposed rule for national emission standards for hazardous air pollutants for Major Sources: industrial, commercial and institutional boilers and process heaters. 75 FR 32006.

In EPA's Proposed Rule, EPA is following the remand and vacature of its earlier standards under § 112. EPA is promulgating these proposed standards based on requiring all major emissions sources to control their emissions using the maximum achievable control technology. EPA also proposes existing major source facilities undergo an energy assessment on the boiler system to identify cost effective energy conservation measures.

CIBO is a broad-based association of industrial boiler owners, architect-engineers, related equipment manufacturers, and university affiliates with members representing 20 major industrial sectors. CIBO members have facilities in every region of the country and a representative distribution of almost every type of boiler and fuel combination currently in operation. CIBO was formed in 1978 to promote the exchange of information within the industry and between industry and government relating to energy and environmental equipment, technology, operations, policies, law and regulations affecting industrial boilers. Since its formation, CIBO has been active in the development of technically sound, reasonable, cost-effective energy and environmental regulations for industrial boilers. CIBO supports regulatory programs that provide industry with enough flexibility to modernize – effectively and without penalty – the nation's aging energy infrastructure, as modernization is the key to cost-effective environmental protection.

This rule is one of four interrelated rules published by the U.S. Environmental Protection Agency (EPA) on June 4, 2010, under the Clean Air Act (CAA) and the Resource Conservation and Recovery Act (RCRA): a rule setting major-source National Emission Standards for Hazardous Air Pollutants (NESHAPs) for industrial, commercial and institutional boilers and process heaters under CAA § 112 (Boiler rule);[1] a rule setting area-source NESHAPs for industrial, commercial and institutional boilers under CAA § 112 (Area Source rule);[2] a rule setting New Source Performance Standards (NSPS) and emission guidelines for commercial and industrial solid waste incinerators under CAA § 129 (CISWI rule);[3] and a RCRA rule defining "solid waste" to demarcate applicability under CAA § 112 and § 129 between boilers and CISWI units (Solid Waste Definition rule).[4]

As an overriding issue, CIBO believes EPA's current schedule, with promulgation by December 16, 2010 is wholly inadequate for the necessary evaluations, deliberations, and revisions that are needed to this Proposed Rule. This rule in combination with the three other proposed

[1] National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, 75 FR 32006 (proposed June 4, 2010) (to be codified at 40 C.F.R. pt. 63)(Boiler Rule).

[2] National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers, 75 FR 31896 (proposed June 4, 2010) (to be codified at 40 C.F.R. pt. 63)(Area Source Rule).

[3] Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Commercial and Industrial Solid Waste Incineration Units, 75 FR 31938 (proposed June 4, 2010) (to be codified at 40 C.F.R. pt. 60)(CISWI Rule).

[4] Identification of Non-Hazardous Secondary Materials That Are Solid Waste, 75 FR 31844 (proposed June 4, 2010) (to be codified at 40 C.F.R. pt. 241)(Solid Waste Definition Rule).

combustion rules presents the largest set or rulemakings from an impact and cost perspective that EPA has ever issued. As such, the const and potential impact on jobs in the US demand a thorough deliberation and thought process so that the most reasonable and defensible rule can be finalized that meets the intentions of the Clean Air Act. Requiring EPA to do all of the work required in less than 4 months puts EPA in an untenable position and the results of having too little time will be a less than optimum regulatory result. Therefore, CIBO recommends that EPA pursue at least 6 months additional time in preparation for promulgation of final Subpart DDDDD, Subpart JJJJJ, Subpart CCCC and DDDD rules.

CIBO members will be directly affected by this and the other related proposed rules and provide these comments to assist EPA to moderate its proposal so that regulated entities can feasibly comply with applicable CAA standards.

SUMMARY OF RULE

On April 29, 2010, EPA issued a proposed rule to regulate hazardous air pollutants from new and existing industrial, commercial, and institutional boilers and process heaters at major source facilities. The Proposed Rule regulates under § 112 of the Clean Air Act major source facilities that emit or have the potential to emit 10 or more tons per year (tpy) of any single air toxic or 25 tpy or more of any combination of air toxics.

The Proposed Rule regulates mercury, other metals, and organic air toxics, which include polycyclic organic matter (POM) and dioxins. It applies to boilers that burn natural gas, fuel oil, coal, biomass, refinery gas, or other gas to produce steam, where the steam is then used to produce electricity or provide heat. It also applies to process heaters, which heat raw or intermediate materials during an industrial process.

The rule creates 11 different subcategories of boilers and process heaters for which the EPA has proposed specific regulations based on the design and fuel of the various types of units. For all new and existing natural gas- and refinery gas-fired units, as well as all existing units with a heat input capacity less than 10 million British thermal units per hour (MMBtu/hr), the Proposed Rule would establish a work practice standard instead of emission limits. The rule does not establish different standards for start-up, shutdown, or malfunction. The rule would also require, as a beyond-the-floor standard, existing major source facilities to conduct an energy assessment to identify cost-effective energy conservation measures.

SUMMARY OF COMMENTS

While CIBO supports EPA's efforts to protect human health and the environment, the proposed Boiler MACT rule sets unachievable standards for boilers and process heaters and fails to provide some reasonable compliance alternatives that would ease compliance with no corresponding increased risk to human health or the environment. This rule, if promulgated as proposed, would create a unacceptable financial burden on CIBO's members without an adequate benefits balancing those costs.

EPA has overstepped its statutory authority and imposes arbitrary requirements in some of the features in the Proposed Rule. EPA does not appropriately account for the cost analysis in some instances as required by the Clean Air Act. Other aspects of the Proposed Rule fail to provide an adequate record to support the proposal. In some cases, the lack of a sufficient record hinders the public's ability to comment on and respond to the Proposed Rule.

SPECIFIC COMMENTS

I. Cost Analysis

EPA's estimated costs of the rule are significantly lower that the real cost impact on sources. CIBO commissioned URS Corporation to work with its members to estimate the capital costs for installation of additional control technologies on existing boilers. The approach used by CIBO and URS (CIBO/URS) to estimate capital costs differed from EPA's in several respects, as described below.

Although EPA's estimates indicate that the total capital cost of the Proposed Rule will be $9.5 billion, CIBO and URS have estimated that the total capital cost of the rule will be over $20 billion for all affected sources for installation of emissions controls on coal, liquid, and Gas 2 boilers. Major capital investments in add-on control technology will be required for continued operation of the industrial, commercial and institutional (ICI) power house and energy base of the country.

Based on EPA's major source boiler inventory database,which includes information on boiler size, fuel, existing controls, and emissions, we estimated costs of controls that would likely be necessary to comply with the Boiler MACT for coal, biomass, liquid, and Gas 2 boilers for units 10 MMBtu/hr and greater. Because the Proposed Rule does not include emission limits for natural gas boilers, these units were considered in a separate cost analysis assuming the work practice standards would not be allowed and the proposed Gas 1 limits in the preamble would be applied, requiring application of control technology to these boilers and process heaters for all regulated pollutants.

Information from various sources was used to determine a base capital cost for a 250 MMBtu/hr boiler and process heater for each PM and HCl control technology option and then scaled using an 0.6 power function based on the size of each boiler and process heater in the inventory. For example, the capital cost of a scrubber on a 100 MMBtu/hr boiler is calculated as the base cost of \$8 million times $(100/250)^{0.6}$. A fixed capital cost of $1 million was assumed for installation of a carbon adsorption system for Hg and/or dioxin control, as these systems do not vary much in cost by boiler size. A fixed capital cost of $2 million was assumed for CO controls (either projects to improve combustion or fuel feed or installation of a CO catalyst). Base cost estimates represent median costs for the various control scenarios based on published reports, industry and vendor information on specific project costs, EPA reports or control device fact sheets, or actual BACT or BART analyses previously submitted to permitting agencies.

To estimate capital costs for each boiler and process heater, we assumed that if there was no emissions information available for a particular unit, the unit would likely need MACT, which EPA stated in the preamble to the proposed Boiler MACT is a fabric filter (FF) plus carbon injection plus wet scrubber plus combustion improvements (or CO catalyst). For PM, if a unit did not already have a FF or ESP and there was information that indicated the unit cannot meet the proposed limit or there was no emissions information, we assumed a new FF. If the unit already had a FF or ESP and there was information that indicated the unit cannot meet the proposed limit we assumed an upgrade to the existing control equipment. To estimate control costs for HCl, if there was information that indicated the unit cannot meet the proposed limit or if there was no emissions information, we assumed either a scrubber upgrade or new scrubber depending on whether the unit currently had a scrubber. For Hg and dioxin, if there was information that indicated the unit cannot meet the proposed limit or if there was no emissions information, we added carbon injection. For CO, if there was information that indicated the unit cannot meet the proposed limit and is not a fluidized bed boiler, stoker boiler, suspension boiler, or dutch oven, then we assumed that capital would be necessary to either perform combustion and/or fuel feed improvements or other boiler/process heater improvement projects to reduce CO or install a CO catalyst.

Our capital cost estimates differ from EPA's cost estimates as follows:

- EPA has used the outdated Control Cost Manual and we have based our cost estimates on more recent information, including actual vendor cost estimates, actual project costs, BACT and BART analyses, industry control cost studies, etc.
- We used a CO catalyst cost 4 times higher than EPA's. The CIBO/URS estimate is based on a recent quote from BASF and EPA's is based on the 1998 Control Cost Manual section on catalytic oxidizers for VOC control.
- EPA has estimated that a tuneup or burner replacement will be adequate for many units to achieve the CO limits. We do not agree with this assumption and have estimated higher costs to implement combustion controls, fuel feed system improvements, or CO catalyst.
- Our estimated CO control capital costs are $1.2 billion for liquid and gas 2 and $1.5 billion for coal and biomass, where EPA's total estimate for CO control capital costs is only $13.9 million, mostly because they have assumed that tune-ups and replacement burners will be adequate for the vast majority of boilers to comply.
- EPA has estimated that activated carbon injection will only be required on 155 existing boilers because installation of a fabric filter is expected to achieve the mercury emission limits, except in cases where a unit already has a fabric filter and does not meet the limits. We do not agree that fabric filters will be sufficient to reduce mercury emissions to the ultra low levels proposed in this rule. There is a flaw in the logic that fabric filters are expected to achieve mercury emission limits when there are many boilers in the database that are equipped with fabric filters and have measured mercury emissions higher than the proposed limits. EPA's estimated industry-wide capital cost for activated carbon injection presented in Table 2 of the cost and emissions impacts memo is extremely low, at only $9.5 million. We do not understand how this can represent 155 boilers; it seems to us to represent the cost 10 boilers would incur to install a carbon injection system. Our estimate for carbon injection required for mercury and dioxin/furan control is $1.7 billion.
- EPA estimated that an ESP would be installed to meet the PM emissions limit unless a unit already had a fabric filter installed. We believe that since sorbent injection will be required for acid gas, mercury, and dioxin control, that fabric filters will likely be chosen for units without existing ESPs in order to maximize the performance of the sorbents and minimize the amount of sorbent used. For example, use of an ESP will

require 4 times the carbon to be injected for mercury/dioxin control than if a fabric filter is used. The capital cost for a fabric filter is higher than the capital cost for an ESP on the same boiler.

- CIBO/URS have estimated a PM control cost for coal, liquid, and gas 2 boilers and process heaters of $7 billion versus EPA's estimated PM control cost of $6.1 billion.
- EPA has estimated costs to install packed bed scrubbers for HCl control. Industrial boilers do not use packed bed scrubbers for acid gas control, as the limitations of these devices make them impractical for use on applications with high flow rates, high PM loading, and high inlet pollutant concentration. EPA's own fact sheet on these devices, located at http://www.epa.gov/ttn/catc/dir1/fpack.pdf, lists these limitations of these devices and indicates that they are only used in applications up to 75,000 scfm, which limits their use to small units only. Facilities will instead install wet scrubbers, dry scrubbers, or semi-dry scrubbers to control acid gas emissions from industrial boilers. EPA has estimated HCl control costs for equipment that industry is not likely to install.
- CIBO/URS have estimated capital costs for coal, liquid, and gas 2 boilers and process heaters for HCl control of $9.3 billion, while EPA's capital cost estimate for wet scrubbers is $3.3 billion.
- EPA presents several cost options in the two ERG memos. Option 2E assumes that facilities will not incur costs to comply with the dioxin/furan standards because they will test for dioxin/furan and be below detection levels. This is illogical, especially because EPA has not outlined in the rule any procedures for handling non-detects when performing compliance testing and there are boilers in the EPA emissions database with dioxin/furan emissions that are non-detect but actually measured emissions higher than the proposed limit. CIBO/URS has estimated carbon injection as the control measure for dioxin/furan emissions and mercury emissions. As stated above, our cost estimate for carbon injection for coal, liquid, and gas 2 boilers and process heaters is $1.7 billion versus EPA's of only $9.5 million.

Item	**EPA Capital Cost**	**CIBO/URS Capital Cost**
CO Controls	$13.9 million	$2.7 billion
Carbon Injection for Hg and D/F	$9.5 million	$1.7 billion
PM Controls	$6.1 billion	$7 billion
HCl Controls	$3.3 billion	$9.3 billion

In the event Work Practice Standards for Natural Gas fired boilers and process heaters are replaced with the numerical standards proposed in the preamble for Gas 1 boilers, the following costs were estimated using the same assumptions as above. We have assumed that gas 1 boilers and process heaters will apply the following technology: FF (for PM), carbon injection (for Hg and D/F), wet scrubber (for HCl), and CO catalyst.

Item	**EPA Capital Cost for Gas 1 Boilers >10 MMBtu (per ERG cost memo Appendix A-1)**	**CIBO/URS Capital Cost**
CO Controls	$3.5 million	$5.8 billion
Carbon Injection for Hg and D/F	$32 million	$2.9 billion
PM Controls	$11.5 billion	$19.6 billion
HCl Controls	$3.1 billion	$23.2 billion

The above estimates could be considered conservative since they assume that emission controls can be installed on existing units and that controls will actually allow compliance with the proposed emission limits. These are very conservative assumptions since it is known that retrofit of emissions control devices such as these is extremely difficult for some units due to design and space limitations, and major issues with the floor setting methodology make achievability of the emission limits highly uncertain. Therefore, it is likely that some combustion units will need to be replaced rather than retrofitting controls to those existing units. Replacement of combustion units could escalate these costs significantly.

II. Unreasonably Short Comment Period

The four interrelated rules raise an unprecedented number of issues for the Agency in determining the appropriate emissions standards for these very large, diverse source categories. Nevertheless, EPA provided only 60 days for regulated sources and other members of the public to analyze and comment on the rules.[5] Affected sources asked EPA for an additional 90-day period to permit affected sources to quality control data, review the database and analysis, consider EPA's proposed and alternative proposed regulatory options, and develop comments that would demonstrate the significant compliance problems with the standards as proposed. CIBO appreciated EPA's agreement to provide an additional 3 weeks for comment for 3 of the 4 rules (EPA did not extend the comment period for the Solid Waste Definition Rule).

It is important to be clear, however, that even with the 3-week extension of the comment period, the time EPA allotted for comment for four interrelated rules of this complexity, broad application and economic impact failed to constitute the reasonable opportunity for public comment guaranteed by the Clean Air Act and the Administrative Procedures Act. 42 U.S.C. § 7607(h) (2006).

In their request for comment to EPA, regulated sources made these and other points to EPA. See Comment Extension Request, Attachment 1; EPA Response, Attachment 2.

[5] In fact, EPA originally provided 45 days for comment on the 4 rules. *See* 75 FR 32682 (June 9, 2010)(extending initial 45-day comment period to 60 days).

Under basic principles of due process and administrative law, EPA must provide the public with a reasonable opportunity to comment on proposed rules. Under the CAA, 30-day comment period would be reasonable for a single, ordinary proposed rule. The truncated comment period violates the clear terms of the CAA and deprives sources of a means to adequately protect their interests and rights in the administrative and judicial processes.

The complexity, breadth of applicability, and economic impact of the proposed rules, and because EPA published the four rules simultaneously, demands even more time to comment, as regulated facilities must also assess the impact of the rules as they interrelate, raising many more operational and practical questions.

The rules will have an extraordinary impact in terms of applicability and compliance costs, covering what EPA estimates to be this scope of facilities nationwide: Boiler MACT rule, 13,555 units located at 1,608 different facilities. 75 FR 32048; Area Source rule, 183,000 existing boilers at 91,000 facilities (75 FR at 31914, 31924) and 6,800 new boilers over the next three years (75 FR at 31914); CISWI rule, 176 units (75 FR at 31950-51); and the Solid Waste Definition rule would cover sources at facilities in at least 85 NAICS codes (75 FR at 31845).

EPA allocated to itself 30 months to collect and analyze data to develop emissions standards and reserved for itself almost 4 months to review comments and prepare a final rule. In contrast to the 34 months that EPA has allocated to its own rulemaking efforts, EPA gave sources 2 months (and an additional 3 weeks) to evaluate the same data and proposed standards, and then write substantive comments that could meaningfully inform the rulemaking process.

EPA adopted a very aggressive timeframe for developing these rules and its database contained countless errors that sources needed to first quality control before analyzing the conclusions EPA reached in reliance on the data. EPA did not make MACT floor memo Excel files available in the docket for the Boiler rule until 3 weeks into the original 60-day comment period.

The rules would also benefit significantly from the generation of additional emissions information. EPA's MACT Floor tables indicate that eleven of the thirty MACT Floor emission limitations for existing sources were determined using less than five sources due to a lack of available data.[6] No time was allocated for additional data-gathering.

III. Variability

A. EPA Did Not Properly Consider and Account for Fuel Variability When Setting MACT Standards.

In evaluating the emission limits achieved by existing sources, EPA is required to estimate the variability associated with all factors that impact a source's emissions, including process, operational and non-technological variables. *See Nat'l Lime Ass'n v. EPA*, 627 F.2d 416, 443 (D.C. Cir. 1980). Any method used to estimate emissions rather than actually measure them "must 'allow a reasonable inference as to the performance of the top 12 percent of units," and EPA must show "*why* its methodology yields the required estimate." *Cement Kiln Recycling*

[6] *See* Table 2 and Table 3, 75 FR 32022-32023 (June 4, 2010).

Coalition v. EPA, 255 F.3d 855, 862 (D.C. Cir. 2001) (emphasis in original) (citing *Sierra Club v. EPA*, 167 F.3d 658, 663 (D.C. Cir. 1999).

EPA has acknowledged this responsibility and identified a number of factors that contribute to variability in emissions test data, including (1) the emission test method; (2) the emission analytical method; (3) the design of the unit and the control device(s); (4) operating conditions of the facility and the control device(s); and (5) the composition and relative amounts of fuel constituents in the fuel or flue gases. *See Prop. Nat'l Emissions Std. for Haz. Air Pollutants for Electric Utility Steam Generating Units*, 69 FR 4,652, 4,670 (Jan. 30, 2004). EPA is correct to incorporate variability analysis into the MACT floor analysis in this rulemaking, but EPA's analysis does not appear to reflect the full range of variables potentially impacting emissions. Variability in boilers depends in part on price fluctuations and changing availability of various fuel types (both between fuel categories and between types of the same fuel, *e.g.*, No. 2 oil and No. 6 oil), as well as a host of other operating and load conditions. While EPA evaluated some of these variables, it did not evaluate a sufficient number to provide "an accurate picture of the relevant sources' actual performance" over the long term. *Cement Kiln Recycling Coalition*, 255 F.3d at 862 (emphasis in original). For example, EPA does not have fuel quality data for all top performers, nor is it clear that EPA made available or utilized all of the fuel quality data that it received for top performers. As a result, commenters cannot review the data to discern the relationship between the fuel quality variability for each top performer and the emissions data.

While this particular shortcoming is shared by the variability analysis for all subcategories, it is most noticeable in the variability analysis for gas-fired units. EPA acknowledges that no mercury or HCl fuel analysis variability factors could be calculated for gas-fired units. *See MACT Floor Analysis (2010) for the Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants—Major Source*, EPA-HQ-OAR-2002-0058-0815, 8 (ERG April 2010) ("*ERG MACT Floor Analysis*"). Fuel gases can have extremely variable HAP content and emissions profiles, yet EPA has provided no rationale for its failure to consider or apply a variability factor for this subcategory. EPA similarly has failed to incorporate data sufficient to demonstrate the extreme diversity of units and of fuel in the liquid fuel subcategory, identifying only one source of data each in the variability analysis for mercury and chlorine.

While EPA did consider a wider range of units for variability in coal, variability in coal quality occurs within individual seams and within one unit's supply, which may come from many different sources, and EPA's testing did not account for this difference in fuel quality. If considering variability in fuel quality across different types of fuel within a single subcategory is too difficult, that may be an indication that EPA should subcategorize based on fuel types down to specific fuels and materials. Additional subcategorizing within fuel groups may be particularly warranted here, given that EPA has (rightfully) ruled out fuel switching, which would in any event be impossible for many regulated sources. Section 112(d)(1) authorizes the Administrator to "distinguish among classes, types and sizes of sources within a category or subcategory," and the Agency's discretion in identifying these subcategories quite broad, perhaps simply "limited by the usual ideas of reasonableness." *See Brick MACT*, 479 F.3d at 885 (Williams, J., concurring).

The overall lack of specific types of data magnifies another problem in EPA's approach to setting the MACT floors: EPA's analysis identifies a number of higher emissions data points that the Agency has excluded as "outliers" without providing sufficient explanation. In addition, EPA appears to have discounted "outliers" for fuel quality but not for emissions data. Without some explanation from the Agency, it is impossible for the public to determine whether this discrepancy in treatment of data is justified. For example, EPA excluded *25%* of the analyzed sources in the biomass fuel category in its mercury fuel analysis variability factor outlier analysis without explaining how fully one-quarter of the sources can be statistical outliers. *See ERG MACT Floor Analysis*, Appendix A-1a. Even the best performing sources occasionally have spikes and those are legitimate data points. *Mossville Environmental Action Now v. EPA*, 370 F.3d 1232, 1242 (D.C. Cir. 2004). The D.C. Circuit has held that an accurate picture of the lowest emission limitation that has been "achieved in practice" refers to the performance of the source "under the worst foreseeable circumstances." *Sierra Club v. EPA*, 167 F.3d 658, 664 (D.C. Cir. 1999). In *Sierra Club*, the D.C. Circuit said that where a statute requires that a standard be achievable, it must be achievable "under most adverse circumstances which can reasonably be expected to recur." *Id.* (citing *National Lime Ass'n*, 627 F.2d at 431 n. 46). "The same principle should apply when a standard is to be derived from the operating characteristics of a particular unit." *Id.* Using fuel quality data over a very limited time period does not provide an accurate picture for overall long term fuel quality variability that is known to occur due to inherent variations in a single supply let alone fuel supplied by many different sources. Again, without some explanation for why EPA has elected to exclude outliers for fuel variability, regulated sources have no way to determine whether the emissions limits proposed by EPA are achievable by the best performers considering the variability in fuel quality. That issue is greatly magnified when taken to the universe of units that are affected sources under this rule, since fuels used by the top performers are in most cases not available to or usable by other affected sources.

As a result of limited fuel quality variability data, EPA has calculated a multiplier factor that has an extremely low variability impact versus the 99% UPL that simply fails to account for all variables and fuel quality variability present in the top 12% best-performing units across all the subcategories, and certainly across all regulated units.

B. Using Emissions Testing Data Does Not Automatically Satisfy EPA's Obligation To Consider All Factors That Affect HAP Emissions.

EPA primarily relies on emissions testing data in determining the proposed MACT floors and corresponding MACT standards. Variability is generally accommodated by performing statistical analyses of the data to predict the upper confidence limit and, therefore, the emissions level above the straight numeric average at which the better performers might be expected to operate. For standards for "fuel related HAP," EPA additionally investigated variability associated with differences in fuel quality over time to a very limited extent only for best performing units. For standards for "combustion-related HAP," EPA additionally investigated variability that might be associated with different firing rates or operating loads. However, there are limitations and problems with EPA's methodology.

As a general matter, we fully support EPA's stated intent to account for variability in emissions from the better performers when determining floor levels of control. Accounting for variability has been upheld as appropriate and lawful by the DC Circuit and, in any event, is necessary to fully characterize the performance of the sources used to set standards under § 112.

Having said that, we are very concerned about the particular method of accounting for variability employed by the Agency in the proposal. EPA proposes to account for both "within test" and "between test" variability by calculating the 99% upper prediction level of the available and relevant emissions testing data. See, e.g., id. at 72976-7.

In concept, such an approach makes sense because setting the floor at the 99% upper prediction limit ostensibly would cause the floor to encompass virtually the entire range of emissions reasonably expected by the better performing sources from which the data were derived if the data encompassed all variations that can impact those emissions and the emissions test/fuel quality data were truly random throughout the population. In practice, however, this approach is flawed because the underlying data are not, in fact, representative of the range of expected operations and true variability that reasonably should be expected from the better performers. The reason is that the emissions data relied upon in the proposal were produced during reference method performance testing under very limited operating conditions, and with a very limited variation in potential fuel quality.

Performance testing is required to be conducted under "representative operating conditions." See 40 C.F.R. § 60.55c(b)(1). The rules do not define the term "representative operating conditions." However, EPA's National Stack Testing Guidance suggests that such conditions: (1) represent the range of conditions under which the facility expects to operate (regardless of the frequency of the conditions); and (2) are likely to most challenge the emissions control measures of the facility (but without creating an unsafe condition). Clean Air Act National Stack Testing Guidance at 14. This guidance further defines "representative" as "normal" as it states that "The MACT program further defines representative performance as normal operating conditions" and again when describing the performances test conditions as described above to be "under…those representative (normal) conditions…." Id. Of course, as expressly stated in the document itself, the National Stack Testing Guidance is "intended solely as guidance" and, as such, "is not a regulation." Id. at 2.

Properly conducted, performance tests are, indeed, a reliable measure of compliance at a given point in time with the relevant standard. However, such tests typically should not be expected to reveal the true range of variability in operating conditions because sources strive to maintain rigorous, yet consistent, operating conditions during tests, between testing runs within a given testing session, and between testing sessions. As indicated by the Stack Testing Guidance, the goal of performance testing is to challenge the applicable control device or control measure to assure that compliance will be maintained under rigorous conditions. Variable operations during testing are inconsistent with the purpose and intent of such testing. In addition, some reference method tests are most applicable for use under steady state conditions.

Moreover, while owners and operators may seek to conduct testing at reasonable worst case conditions to assure compliance during less rigorous conditions, it is entirely possible that operations during less rigorous conditions could nevertheless accommodate operational variation that would not threaten compliance with the standard, but could be relevant when the data are used to set standards on a pollutant-specific basis rather than a unit-specific basis. As a hypothetical example, the most rigorous testing condition for HCl emissions from a given boiler might be a fuel with high halide content. Thus, it would be logical for testing to be performed under these conditions. However, other HAP constituents in the fuel – such as metals – would not necessarily be at "worst case" levels during testing focused on halides. In this scenario, the testing might show extremely low levels of metals emissions, which would not necessarily reflect higher levels of such emissions that might occur during normal operations. It is also typically not feasible to actually obtain "worst case" fuel quality for emissions testing purposes simply due to natural variability in fuel quality, especially coal.

In order to address these limitations, CIBO recommends that EPA utilize a site specific fuel analysis plan approach and correlate fuel quality during emissions testing to emissions measured, and then use ongoing fuel analysis on an appropriate time basis to determine ongoing compliance based on emissions control performance achieved during the emission test. For example, some existing coal fired units might be conducting daily coal sampling and analysis for sulfur and HHV, so accumulating the individual coal samples for a month and preparing a monthly composite for HHV, S, Cl, and Hg analysis would allow determination of projected emissions over that month for the operational boilers. In that way, a 12 month rolling average emission rate could be determined relative to the emission limit. This approach would then allow use of actual fuel quality during the emissions test to not become an artificial limit to operation of the units, while still assuring emissions comply with the limits.

C. The Proposed Emission Standards for Hydrogen chloride and Mercury Do Not Fully Account for the Variability in the Nation's Coal Supply.

EPA should use long term fuel quality data for top-performing units to determine the impact of fuel quality variability on MACT floors. EPA explains in its MACT Floor Memo and in the Proposed Rule that it used fuel data from a 30 day period from each of the top performing units in each subcategory to arrive at a fuel variability factor, which was then multiplied by the MACT floor emission rate. 75 FR 32,021. This was EPA's attempt to account for long term variability in each fuel.

CIBO agrees with EPA that using stack test data alone does not reflect variability of fuel-dependent related HAP for the top performing sources. However, we disagree that data taken from a 30 day period of time from just five coal fired boilers during the same general time period (all units testing under the ICR did so during the same few month period of time) reflects long term variability. While we recognize EPA's efforts to account for variability, we believe it is totally inadequate. For example, many of the top performing units in multiple subcategories do not have fuel quality data corresponding to the emissions test data. This alone is a fatal flaw in the fuel quality variability approach. This flaw is then compounded by not having fuel quality data for those top performers over a long enough period of time to account for potential quality variability due to several factors: variability of a single fuel supplier's quality (e.g., single coal mine); variability due to fuel obtained from multiple suppliers due to market forces or other issues; variability due to fuel oil crude oil quality, which is totally outside the control of the affected sources under this rule; variability due to natural occurrences, such as storms or other occurrences which can impact fuel quality, most notably biomass.

While EPA believes it is limited to considering variability applicable to the top performers, the subcategories and specific sources used to determine the MACT Floors inherently presents a bias against all other sources in the subcategories since they simply in many cases cannot use the specific fuels utilized by the best performers due to availability or inherent equipment designs. Unless EPA applies additional variability to account for those additional factors to the top performers, the resultant rule is inadequate and does not demonstrate potential performance of those sources under worst case conditions that can be expected to occur and therefore, does not meet the 112 requirements. Limitations of the best performers under specific subcategories is explained elsewhere in these comments.

EPA's results were also significantly altered by its treatment of outliers using the Interquartile Range methodology. This methodology is not appropriate for such a small dataset and it defeats the purpose of accounting for variability in the fuel. We note also that EPA made no attempt to identify outliers (i.e. low values that stand apart from the dataset) when determining the emission levels achieved by top performers, so we see no rationale for doing so in this context unless specific data represents an obvious error.

EPA's method for identified outliers first determined the "fuel variability factor" for each unit by dividing the highest chlorine concentration reported for the unit's fuel supply by the chlorine concentration during the stack test (after applying calculated control efficiency). Then, it determined the quartiles of that data set and called any value in the first or fourth quartile an outlier.

This methodology does not identify a real outlier – a value that stands apart from the dataset. In fact, two of the top performers for the coal subcategory were identified as outliers. These two, the unit at Purdue University and Eastman's Boiler 30 both submitted a large amount of data from outside the 30 day ICR test period. We believe the reason these were outliers is because these units had enough data to catch a high value of chlorine, reflecting the real long-term variability of the coal supplied to the units. If EPA were to have included these units, the average fuel variability factor would have been 3.49 instead of 1.51. This illustrates the flaw in EPA's methodology. By its design, it obscures and underestimates the true variability.

CIBO does not see the need to complicate the analysis by including the control efficiency of the boilers as EPA explains in its MACT floor analysis memo. All EPA needs to do is collect coal chlorine data and mercury either directly from the sources or from the suppliers that serve the top performers. If units do not have a large data set, then EPA should collect chlorine data available from the coal suppliers. Then, EPA should determine the UPL at the 99th confidence level for chlorine and mercury fuel content using all the data available for the unit and calculate the ratio of the UPL to the average chlorine or mercury content during the top performing stack test. Then, similarly to what EPA did in Appendix A-2c to the MACT Floor Memo, take the average of these ratios from the top performers for which fuel data is available from the unit's best test and use that result as the Fuel Variability Factor.

Once EPA sets the MACT floor emission standards in this way, as is discussed elsewhere in these comments, EPA should allow compliance with the standard to be demonstrated using long term averages of the chlorine and mercury content in the fuel. The proposed method of conducting one time sampling events and determining the 90th percentile based on as few as three composite samples, and then pre-qualifying any future fuel suppliers is unworkable, especially for complex facilities with multiple and ever-changing fuel suppliers and markets.

D. A Fuel Dependent Variability Factor Should be Used to Account for the Range of Fuels Used by ICI Boilers and Process Heaters and Other Equipment Variabilities Need to be Considered.

The fuel used by industrial, commercial, and institutional (ICI) boilers is much more diverse than that used by utility boilers. While some of that variability is included within the range of emissions test data, the full range of fuels has not been addressed in the MACT floor emission rate setting process.

As noted by EPA, mercury emissions are dependent on the amount of mercury in the fuel burned. CIBO includes members that fire a range of fuels, from anthracite culm to bituminous coal to lignite, therefore, CIBO is very concerned that the emission limit determined by EPA to be the MACT floor be achievable by members' units with application of appropriate control technology. As stated in an EPRI report,

> "the distributions show that subbituminous coal has about 20% less mercury per Btu than bituminous coal while lignite has about 10 to 20% higher levels .... Further, it will be shown that the higher chlorine fuels (typically bituminous coal) have a higher percentage of mercury capture by conventional control technologies]. *An Assessment of Mercury Emissions from U.S. Coal-fired Power Plants,* EPRI, Palo Alto, CA, TR-1000608, at 2-4 (Oct. 2000).

This conclusion indicates that the high level of variability present in the diverse range of fuels used by ICI boilers needs to be taken into account in determining the emission limit for existing solid fuel fired sources. The EPRI report, p.3-30 also provides some insight on mercury removal with fabric filters as follows based on the emissions testing that was conducted: the removal data appears to be bifurcated. Four of the sites show >80% removal, regardless of the chlorine level, while six sites follow the increasing chlorine, increasing removal trend. It is highly likely that the low chlorine, high removal sites also have ash with adequate levels of certain forms of unburned carbon (high mercury capacity and high surface area) ....This category clearly has additional parameters which affect the speciation and the oxidation. However, these parameters cannot be identified with the existing dataset. Consequently, predicted emissions for this class of unit are expected to have a large variability from actual levels.

Thus, there are additional variabilities in the mercury removal performance of fabric filters that need to be taken into account when establishing an emission limit that can be achieved by similar solid fuel fired sources. ICI solid fuel fired boilers exhibit a wide range of unburned carbon content in fly ash, and that can impact mercury removal in fabric filters as indicated in the EPRI report. The unburned carbon content varies among types of boilers (stoker vs pulverized coal) and between similarly designed units, depending on fuel, equipment, and operating variations. CIBO urges the EPA to consider and apply an additional overall fuel variability factor to the emission limit with variability resulting from consideration of the above comments.

EPA summarizes in Table 2 on 75FR32022 the MACT Floor results for fuel related HAP foe existing subcategories. It is noteworthy that the multipliers for fuel variability where applied are so low (1.18x to 2.47x). It is also notable that EPA applied no fuel variability factor to the gas 2 (other gas) limits. Considering the extreme diversity of other gases, this illustrates the inadequacy of data and analysis for other gases.

E. EPA Did Not Have Sufficient Data to Determine Effect of Fuel Variability.

EPA should account for fuel variability when establishing the MACT floor. EPA did not have sufficient data to determine the effect of fuel variability. This is apparent considering that EPA did not have fuel quality data for top performers in addition to the fact that it failed to rely on continuous emission monitoring system (CEMS) data in conducting the MACT floor analysis.

EPA could not have performed an accurate assessment of fuel quality variability for top performers because it simply did not have the data for those units. Additionally, any assessment by EPA of fuel variability would be lacking based on the agency's failure to include continuous emission monitoring system (CEMS) data in the MACT floor analyses and the HWC MACT statistical methodology employed. CIBO notes that EPA did not include CO data from CEMS that was provided by companies and resides in EPA's databases.

Although we have no idea why EPA chose to exclude CEMS data from its MACT floor determinations, one possibility is that EPA may believe it is not feasible to incorporate CEMS data along with stack test data in its MACT floor analyses due to the method it has chosen to rank and statistically analyze the data. It has chosen to identify top performers by using the lowest 3-run stack test and then use all the run data from the top performers to determine the Upper Predictive Limit (UPL) of the data set.

A better methodology is that used by EPA in the Hazardous Waste Combustor MACT. Here, the Upper Predicted Level (UPL) is determined for each unit using all the test data available, ranking the units by the UPL, and then determining the UPL for that dataset (see the Technical Support Document for that rule, Volume 3 pages 7-6 and 7-7). This methodology would allow CEMS data to be used along with stack test data and the UPL determined for each such unit. EPA should obtain hourly average CEMS data over a period of time (months or as much data as can be readily obtained) from each source it can identify that either has a permanent CEMS installed on the unit or provided data in its response to the ICR survey or testing program. These hourly averages should then be used to establish the UPL for that unit. This data from these units with CEMS data should be combined with stack test data, all the UPLs determined, and the top 12 percent performers determined from the UPLs, and the UPL for the subcategory determined as done using the HWC MACT methodology. This procedure should be used for CO, and this way, EPA can more appropriately account for intra-unit emission rate variability.

A unit that simultaneously burns two different fuel types in separate burners will have a harder time controlling CO (particularly when the load is variable) as compared to less complicated units. Once again, EPA has limited data that it cannot legitimately draw the many conclusions it has in the Proposed Rule. The units evaluated by EPA in the load variability assessment are the following.

CA-Tesoro - Process Heater - Unit has no "end-of-pipe" controls. The unit appears to burn 100% gas (Gas 1).

WA-Boeing (Renton) - Boiler (Boiler 04) - Unit has no "end-of-pipe" controls. The unit appears to burn 100% gas (Gas 1).

TX-Temple Inland (Diboll) - Boiler (PB44) - Unit is controlled with an ESP. The unit appears to burn 100% "dry" biomass.

AR-Domtar - Boiler (PB1) - Unit is controlled with a wet ESP. The unit appears to burn a combination of gas and "wet" biomass. (EPA ultimately rejected this unit from the Boiler MACT inventory because it also burns "fuel cubes" (a waste)).

VA-PhillipMorris (Park 500) - Boiler (B3) - Unit is controlled with an ESP. The unit appears to burn 100% coal.

WV-Dupont (Washington Works) - Boiler (P05) - Unit is controlled with a Multiclone/Duct Sorbent Injection/Fabric Filter system. The unit appears to burn 100% coal.

IV. Fuel Switching.

CIBO agrees with EPA that "fuel switching is not an appropriate control technology for purposes of determining the MACT floor level of control for any subcategory." 75 FR 32019. As recognized by EPA in the preamble to the Proposed Rule, fuel switching is not a feasible alternative because (i) it will not result in lower HAP emissions; (ii) it presents numerous technical and design related issues for existing units; and (iii) can result in the crippling of certain units that are not able to obtain the alternative fuel due to their geographic location or lack of appropriate infrastructure. However, despite its conclusions regarding fuel switching, EPA has proposed a rule with such unachievable standards that it will discourage the reliance on coal and other solid fuels. There is no legal basis to effectively eliminate coal as a viable fuel and there are multiple barriers, some insurmountable, to using gas in place of coal.

A. Fuel Switching is Not a Viable Regulatory Option for MACT Floor or for Beyond-the-Floor Considerations.

CIBO agrees with EPA that "fuel switching is not an appropriate control technology for purposes of determining the MACT floor level of control for any subcategory." 75 FR 32019. EPA correctly notes in the preamble discussion that the emission rate of some organic HAPs such as formaldehyde are higher for gaseous fuel firing than for liquid or solid fuel firing. 75 FR 32019. Natural gas is the alterative fuel normally considered for fuel switching comparisons. When fuel switching to natural gas occurs, there is an increase in some HAP emissions compared to units firing coal. In such a situation, the increase in certain HAPs when firing natural gas offsets the reduction in other HAPs when a unit ceases to fire coal. These issues can also arise when switching to so-called "cleaner" fuels within a subcategory. As noted by EPA in the preamble, some "cleaner" coals that offer lower sulfur content many "not necessarily [result in] lower HAP content." 75 FR 32019. Additionally, fuel switching from coal to biomass may result in a reduction of metallic HAP emissions, but would increase emissions of organic HAPs. 75 FR 32019. This situation makes the determination of overall benefit extremely problematic.

There are serious technical and design issues that could arise with existing units that are forced into fuel switching to "cleaner fuels" within a subcategory. EPA acknowledges in the preamble to the Proposed Rule, that switching fuels burned by a boiler or process heater could result in the need for "extensive changes to the fuel handling and feeding system." 75 FR 32019.

Beyond increases in HAP emissions and technical infeasibility, fuel switching remains an infeasible means of establishing MACT floors when considering availability of the alternative fuel. Natural gas is simply not available at many industrial locations and very costly to obtain at others. This problem is particularly highlighted when considering standards that force fuel switching from solid fuels to natural gas. Natural gas requires extensive infrastructure, and as EPA states in the preamble, "[n]atural gas pipelines are not available in all regions of the U.S., and natural gas is simply not available as a fuel for many industrial, commercial, and institutional boilers and process heaters." 75 FR 32019. Even if appropriate infrastructure exists, limited natural gas supplies could pose another availability issue. According to a report by the National Energy Policy Development Group, the nation's dependence on natural gas will increase to nearly 40 percent of total electric generation. *Reliable, Affordable, and Environmentally Sound Energy for America's Future, Report of the National Energy Policy Development Group* (National Energy Policy Document), at 5-14 (May 2001). Such an increase will need to be supported by increased natural gas production. Regulatory proposals that force industry to increase their reliance on natural gas will only increase the demand for natural gas with no clear picture of how or when production will increase.

B. Regulatory Barriers Make Fuel Switching Difficult.

Even if a coal fired source tries to switch to natural gas, it is quite possible that regulatory authorities will treat the existing solid fuel fired units as new gas fired units, thus providing further disincentive to that option. A significant unintended negative consequence has been discovered when this rule is interpreted at the state level. A large educational institution that is exploring the option of switching from coal/natural gas firing to natural gas firing alone has been told that this project will trigger new source review (NSR). The state regulatory agency has determined that no allowance will be made for the emissions reduction due to diminished coal use and that the institution will have to perform an Applicability Analysis calculating the emissions increase due to increased natural gas use. The institution is increasing its consumption of natural gas from 3% of its total Btu requirement to 100%. This increase will trigger NSR for NOx and PSD for CO even though the net decrease in each case will be 65%. This errant fuel-by-fuel interpretation at the state level will result in a stringent application review and controls far beyond the intent of the Boiler MACT.

Natural gas is not available in all locations; this is especially relevant for liquid-fired units with unachievable MACT standards. Small to medium size boilers and process heaters typically use fuel oil where natural gas is not available.

Natural gas distribution lines do not extend to typical industrial locations in rural areas. It is critical to recognize that the overall distance required to connect industrial consumers could be significantly longer than the ten miles assumed for the worst case condition by EPA in docket memo 11B- H, Development of Fuel Switching Costs and Emission Reductions for Industrial /Commercial / Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants, at p.6. Price spikes of 2000-2001, 2003, 2006, and 2008 are indicative of the potential costs that could be incurred if forced fuel switching was considered, over and above those already considered by the EPA in its analysis. Continually increasing demands for use of natural gas in other sectors will drive the price of gas up even more. While shale gas supplies can provide increased supply, there are limitations on how far and fast that supply can increase. Multi-pollutant proposals and other climate change initiatives can also drive increased demand for gas, making the availability and competitive price of gas for industrial, commercial, and institutional boilers even more problematic.

Forced fuel switching to natural gas as a beyond-the-floor requirement would also need to include the collateral impact of higher gas prices on other gas users, including small businesses and residential users. EPA's approach of rejecting fuel switching as a regulatory option in this rulemaking is, therefore, not only prudent relative to use of all natural resources in the United States, but also the only defensible decision possible. The increasing demand for natural gas also brings to light constraints in the supply of natural gas that is indirectly recognized in this rule. If this rule forced fuel switching to natural gas, then the owner/operator would be forced to evaluate alternative fuels during periods of gas curtailment in order to ensure the continued operating reliability of the boilers and process heaters **.**

V. Floor Setting Method.

The purpose of the floor setting procedure is to discover what techniques the "best performers" use to achieve low emissions so that the other, higher emitting sources in the category or subcategory can replicate those actions and achieve those same low levels. As EPA noted in *Cement Kiln Recycling Coalition v. Environmental Protection Agency,* 255 F.3d 855, 863 (DC Cir. 2001) (Cement Kiln), the intent of the standard setting process is to discover the "objective, duplicable control" techniques so that other performers in the source category could emulate those techniques, reduce their emissions, and achieve those levels. *See* EPA Response Brief, *Cement Kiln*, at. n. 57.

Reproducibility is included in the statute's floor setting provisions as well. Section 112(d)(3) states that that the floor standards reflect the average emission limit achieved by the best performing sources (for existing sources) or the emission control achieved in practice by "best controlled similar source" (for new sources). This reflects the Congressional directive that the best performers must actually be controlling their emissions and their technique must be capable of being reproduced by others in the source category. Thus, the Agency's floor determination must discover the techniques that the best performers are using to actually "control" emissions, i.e., exercising some degree of management that is duplicable by others. The Agency's analysis, therefore, must determine what is the maximum degree of reduction that the best similar source achieves through methods of control.

EPA states in the preamble that MACT is use of a fabric filter, carbon injection, scrubbing, and good combustion practices (or CO catalyst). This would lead one to believe that boilers utilizing these control technologies would meet the MACT limits. However, there are two coal-fired boilers at OHMortonSaltRittman (B002 - Coal-Fired Boiler #2 and B003 - Coal-Fired Boiler #1) that, based on the data in EPA's database, do NOT meet the proposed MACT standards. This points to the lack of consideration of achievability and technology factors in EPA's standard setting process, and that the use of the technology specified by EPA as MACT may not always be able to achieve the proposed limits.

A. EPA's Statistical Approach is Flawed.

1. EPA has relied on data sets that are not statistically significant.

The statistical method used by EPA in setting MACT floors is flawed due to the use data sets that are not statistically significant. The following comments detail why the current proposal is unacceptable.

Obtaining long term fuel data is essential in establishing the MACT floors that units must adhere to. EPA did not consider long term data for liquids in the Proposed Rule. CIBO recommends that EPA collect long term data on liquid fuels for all top performers to ensure that the analysis is complete. Additionally, it is widely accepted that a general theme of the Clean Air Act is to use as much data as possible. While this is the case, EPA adheres to this tenet only when it sees fit. For instance, in setting MACT floors EPA included no data on liquid fuels, while in other situations EPA chooses to include data that is not statistically significant. In addition, EPA utilized no long term CEM data for liquid fired units, which raises significant issues considering the number of boilers and process heaters utilizing fuel oil.

EPA relied on limited data sets for setting the MACT floor in the Proposed Rule. 75 FR 32023. It is simply in appropriate to use one or two units to set the floor for all units in a subcategory. Generally, data sets of less than 30 are not statistically significant and inappropriate without additional tolerance. CIBO recommends that EPA use a minimum of five units to base floor calculations when less than five units are used as the 12 percent of units with data. Furthermore, EPA should use the upper tolerance limit (UTL), which acknowledges when a data set is not statistically significant. In the case of organic HAP, an extremely small number of units were used to set the MACT floor.

2. EPA switches between different methods of statistical analysis.

In conducting its statistical analysis to support the establishment of new MACT floors, EPA indicates that it is relying on the 99 percent upper predictive limit (UPL). 75 FR 32020. However, it appears that EPA is simply switching between several different statistical methods. The UPL predicts future performance of a data set and assumes the dataset is representative of the population and then makes a prediction. 75 FR 32019-20. The upper tolerance limit (UTL) is meant for use in situations where the amount of data available does not represent the entire population, where uncertainty is greater, and the dataset is not statistically significant. The UPL results in lower numbers while the UTL results in larger numbers. The UTL is also to be used when the bounds are greater. The upper confidence limit (UCL) bounds the mean of the data set.

The Proposed Rule uses an approach from the Hospital/Medical/Infectious Waste Incinerators (HMIWI) MACT. *See generally* Standards of Performance for New Stationary Sources and Emissions Guidelines for Existing Sources: Hospital/Medical/Infectious Waste Incinerators;

Final Rule 74 FR 51368 (Oct. 6, 2009). EPA refers to a UCL; however, it is really more of a UL. EPA should use the UCL and the correct equation. Furthermore, EPA indicates that its 99 percent UPL approach includes long term variability; however, based on the nature of the method that is not possible.

B. EPA Has Not Used Data Representative of the Actual Performance of the Top 12% Best Performing Sources.

1. EPA Has Improperly Used the Top 12% of the Top 12% to Set the MACT Floor, Rather Than the Top 12% of All Sources Within a Certain Category.

Clean Air Act § 112(d) requires EPA to set a MACT floor for existing sources that is not less stringent than "the average emission limitation achieved by the best-performing 12 percent of the existing sources (for which the Administrator has emissions information)." *See* 42 U.S.C. § 7412(d); *Nat. Res. Def. Council v. EPA*, 489 F.3d 1250, 1254 (DC Cir. 2007). The top 12% "best performing" sources are known as "MACT floor units" or "units comprising the MACT floor."

During the Phase I Boiler MACT data collection effort, EPA requested and received emissions data from most of the potentially affected sources across all of the subcategories for PM, CO, NOx and many HAPs. After sifting the Phase I data, EPA developed a Phase II plan for collecting additional data, which identified the specific tests that would be required for the different HAPS. The Phase II plan consisted of two rounds of testing. The first round consisted of an outlet stack test (three runs) for PM (filterable, condensable, and PM2.5), dioxin/furans, HCl/hydrogen fluoride, mercury, metals, CO, THC, formaldehyde, NOx and SO2. In addition, six facilities (two coal-fired, two biomass-fired and two gas-fired boilers) were required to collect CO, THC and NOx CEM data over 30 operating days. Each selected unit was also required to collect and analyze the materials fed to the combustion unit during each stack test. 75 FR 32,010. In selecting units for this Phase II testing, EPA targeted coal and biomass-fired boilers and any boiler that indicated that it burned waste. During this second round, however, EPA targeted only those sources whose data EPA determined it would need to set the MACT floor. *Id.* In this way, EPA artificially limited the pool of data from which it drew its top 12% best performing sources. This is patently at odds with section 112(d) and with the intent of Congress in establishing this framework, which is intended to maximize the data considered by EPA. The result is completely arbitrary because EPA's sampling approach for Phase II created a dataset that is not random and, therefore, not representative of sources for which the data is being used to infer emissions.

Representativeness may be considered as the measure of the degree to which data accurately and precisely represent a characteristic of a population. *Guidance on Choosing a Sampling Design for Environmental Data Collection*, EPA QA/G-5S, p. 1 (U.S. EPA 2002). In Phase II of the data collection, ICR, EPA did not randomly select sampling units, a hallmark of probability-based sampling. Rather, EPA selected sampling units based on its understanding of which sources it would likely include in the MACT floor(top performing units). EPA's approach is a form of "judgmental sampling," which EPA defines at the "selection of sampling units on the basis of expert knowledge or professional judgment." *Id.* at p. 10. According to EPA, probabilistic sampling is preferable where EPA wishes to draw quantitative conclusions about the sampled population through statistical inferences. *Id.*, p. 10-11. When using judgmental sampling, however, EPA states that "statistical analysis cannot be used to draw conclusions about the target population," and "quantitative statements about the level of confidence in an estimate (such as confidence intervals) cannot be made." *Id.* at p. 11. Yet this is precisely what EPA has done in the proposed Boiler MACT. EPA's Phase II data collection is being used incorrectly to make statistical inferences about emissions of boilers in any given subcategory overall.

This approach does not meet EPA's own standards for data quality:

> Judgmental sampling has some advantages and is appropriate in some cases, but the reviewer should be aware of its limitations and drawbacks. This type of sampling should be considered only when the objectives of the investigation are not of a statistical nature (for example, when the objective of the study is to identify specific locations of leaks, or when the study is focused solely on the sampling locations themselves). Generally, conclusions drawn from judgmental samples apply only to those individual samples; aggregation may result in severe bias due to lack of representativeness and lead to highly erroneous conclusions…Using a probabilistic statement with a judgmental sample is incorrect and should be avoided as it gives an illusion of correctness where there is none.

Data Quality Assessment: A Reviewer's Guide, EPA QA/G-9R, p. 11 (U.S. EPA 2006). This severe bias is evident in the MACT floors set by EPA, which were set not by examining data from randomly-selected sources representative of the sources as a whole, then averaging the 12% best-performing sources, but rather by examining data reflecting only EPA's best guess as to the best-performing sources, and then averaging the 12% best-performing of those. This fundamentally skewed the universe of data that EPA had to consider, and it led to the arbitrary outcome of floors that are more stringent than would have resulted from a fair and random sampling of the regulated sources.

2. The Lowest-Emitting Sources Are Not Representative of the Actual Performance of the Best Performing Boilers, and EPA Should Use the Relative Performance of Air Pollution Control Technology to Select the Best Performing Sources.

EPA has established the proposed Boiler MACT floors by equating sources with the lowest emissions for particular HAPS with best performing sources and ignoring other measures of performance that might more accurately demonstrate the best performing sources.

Section 112(d) requires the MACT floor be no less stringent than "the emissions control achieved in practice by the best controlled similar source" for new sources, and the "average emission limitation achieved by the best performing 12 percent of the existing sources," for existing sources. Simply put, if Congress intended the MACT floor to be no less stringent than "the lowest emission levels" achieved by sources, it could have said so. "Best controlled" and "best performing" are not synonymous with "lowest emission level."

The DC Circuit has never required that EPA equate the "lowest emitting" sources to the "best performing" sources. *See Sierra Club v. EPA*, 167 F.3d 658, 661 (DC Cir. 1998) (section 112(d) "on its own says nothing about how the performance of the best units is to be calculated"). In its review of the 1999 portland cement MACT standards, the court endorsed a "technology approach" to setting the MACT standard, whereby EPA would use the relative performance of air pollution control technology to select the best performing sources. In rejecting the view that emissions are the only factor EPA must consider, the DC Circuit stated:

> According to the Sierra Club, section 7412(d)(3) requires EPA to set new source floors at the lowest recorded emission level for which it has data and existing source floors at the average of the lowest twelve percent of recorded emission levels for which it has data. Nothing in the statute, Sierra Club argues, permits the Agency to set floors based on the performance of technology as opposed to the recorded performance of plants.
>
> In resolving this issue, we do not write on a clean slate. EPA's technology-based approach to setting new source emission standards has already faced and survived a *Chevron* one challenge. In *Sierra, 334 U.S. App. D.C. 421, 167 F.3d 658*, we reviewed a new source emission standard for solid waste combustion that EPA promulgated pursuant to section 7429, which establishes emission requirements virtually identical to section 7412's. There, as here, the Sierra Club argued that EPA's MACT technology approach to setting emission standards is unambiguously forbidden by the Clean Air Act. *Sierra* rejected that argument, holding that EPA may estimate the performance of the best performing units and that it was not "impossible" that EPA's methodology constituted a reasonable estimation technique.

See 167 F.3d at 665.

Nat. Lime Ass'n v. EPA, 233 F.3d 625, 631 (DC Cir. 2000). Thus, the DC Circuit in *Nat'l Lime* endorsed EPA's use of a technology-based approach that uses the relative performance of pollution control technology to set the MACT floor.

This was the approach adopted by EPA in the promulgated MACT. There, EPA recognized that while it may be appropriate in certain circumstances to consider primarily available emissions test data, such an approach was ill-suited to setting the boiler MACT floor:

> [A]fter review of the available HAP emission test data, we determined that it was inappropriate to use this MACT floor approach to establish emission limits for boilers and process heaters. The main problem with using only the HAP emissions data is that , based on the test data alone, uncontrolled units (or units with low efficiency add-on controls) were frequently identified as being among the best performing 12 percent of sources in a subcategory, while many units with high efficiency controls were not. However, these uncontrolled or poorly controlled units are not truly among the best controlled units in the category. Rather, the emissions from these units are relatively low because of the particular characteristics of the fuel that they burn, that cannot reasonably be replicated by

> other units in the category or subcategory. A review of the fuel analyses indicate that the concentration of HAP (metals, hydrogen chloride (HCl), mercury) vary greatly, not only between fuel types, but also within each fuel type. Therefore, a unit without any add-on controls, but burning a fuel containing lower amounts of HAP, can have emission levels that are lower than the emissions from a unit with the beset available add-on controls. If only the available HAP emissions data are used, the resulting MACT floor levels would, in most cases, be unachievable for many, if not most, existing units, even those that employ the most effective available emission control technology.

69 FR at 55233 (emphasis added).

It appears that EPA's decision to equate best performance with lowest emissions, rather than with any other means of measuring performance, is based on a parenthetical phrase found in the *Brick MACT* decision, which refers to the "best performing" sources as "those with the lowest emission levels." This isolated statement is dictum; it is not a necessary underpinning of the *Brick MACT* decision, nor is it supported by any other DC Circuit decision.

In *Brick MACT*, the DC Circuit affirmed its decision in *Cement Kiln* that EPA cannot redefine "best performing" to mean those sources with emission levels achievable by all sources:

> But EPA cannot circumvent *Cement Kiln*'s holding that Section 7412(d)(3) requires floors based on the emission level actually achieved by the best performers (those with the lowest emission levels), not the emission level achievable by all sources.

Brick MACT, 479 F.3d at 880-81 (citing *Cement Kiln*, 255 F.3d at 861). EPA interprets this dictum (it was unnecessary to resolution of the issue before the court) to prohibit the adoption of any measure of 'best performing" other than lowest emission levels. This is an unnecessarily narrow view of the language in *Brick MACT.* For one, the *Brick MACT* decision did not overrule either of the *Nat'l Lime* or *Sierra* decisions, in which the D.C. Circuit approved approaches that did not simply equate "best performing" sources with "those with the lowest emission levels." Faced with demonstrably contradictory yet binding precedent, EPA has without explanation elected to follow non-binding language that would appear to place great restraint on EPA's discretion. It is unclear why EPA is so willing to sacrifice its discretion on this issue when it has repeatedly asserted its discretion to characterize "best performing" sources by criteria other than simply the lowest emission level.

Indeed, EPA has not explained why the parenthetical in *Brick MACT* is a legally-binding interpretation of the statutory language rather than simply an explanatory description of the yardstick for measuring "best performers" in *Cement Kiln*. If the D.C. Circuit has been explicating the *National Lime* or *Sierra* cases, perhaps it would have used a different description of the "best performer" that comported with EPA's approach in those rulemakings. There is simply no reason to read the *Brick MACT* language the way EPA does here when there is an alternative interpretation that harmonizes *Brick MACT* with prior and still binding case law.

Furthermore, EPA's interpretation of *Brick MACT* collides with Section 112(d)(3) and other D.C. Circuit decisions requiring EPA to take nontechnological and nonintentional factors into consideration if they impact emissions levels achieved in practice by sources, particularly as EPA is also advocating a "pollutant-by-pollutant" approach to setting the MACT floor. For example, if a source utilizes a technology that dramatically lowers its emissions of a particular HAP but at the same time increases its emissions of other HAPs or other air pollutants, EPA takes those factors into account when setting the MACT floor and must devise a reasonable way to address such factors in its methodology. But under EPA's interpretation of *Brick MACT*, EPA would be constrained to identify the lowest emitters of that particular HAP as the best performing sources regardless of any collateral negative impacts. EPA certainly has more discretion than that.

EPA itself has, since *Brick MACT*, acknowledged its discretion to define "best performing" sources in a manner that accounts for all the relevant factors. Though for some reason EPA modified its approach in the final rule, in its notice of the proposed Hazardous Waste combustor ("HWC") Reconsideration Rule, EPA justified using control efficiency rather than the simplistic emissions levels in defining "best controlled" and "best performing" hydrochloric acid production furnaces:

> First, the statutory language requiring floors to be based on "best controlled" (new)/"best performing" (existing) does not specify whether "best" is to be measured on grounds of control efficiency or emission level. *See Sierra Club v. EPA*, 167 F.3d 658, 661 ("average emissions limitation achieved by the best performing 12 percent of units…on its own says nothing about how the performance of the best units is to be calculated"). The requirement that the new source floor reflect "emission control" achieved in practice reinforces that the standard can be determined and expressed in terms of control efficiency. Existing floors determined and expressed in terms of control efficiency are likewise consistent with the requirement that the floor for existing sources reflect "average emission limitation achieved," since "emission limitation" includes standards which limit the "rate" of emissions on a continuous basis—exactly what the standards do here. CAA section 302(k). Moreover, where Congress wanted to express performance solely in terms of numerical limits, rather than performance efficiency, it said so explicitly. See CAA section 129(a)(4).

Solicitation of Comments on Legal Analysis, 72 FR 54875, -84 (Sep. 27, 2007). While the HWC Final Rule hews to the unduly narrow view of the *Brick MACT* decision embraced by EPA here, in it EPA nonetheless observed that "Standards requiring HAP reduction of a given percent limit the emission quantity, rate, and (in any realistic scenario) concentration of the HAP and so falls squarely within the statutory definition [of emission standard]." *See Reconsideration Final Rule*, 73 FR 64068, -87 (Oct. 8, 2008).

EPA takes an unnecessarily narrow view of *Brick MACT*, compelled neither by section 112 nor by the D.C. Circuit's opinion itself, robbing itself of the discretion to engage in an analysis that reflects reality. EPA has historically demonstrated persuasively why the Agency might in its discretion choose some other or more complex measure of what a "best performing" source is. The data here indicates that such an approach—which accounts for operational and other variability that undermines any straightforward connection between the "lowest emitters" and the "best performing" sources—would be justified.

C. CO Emissions Variability Data was not Considered in Setting Limits.

EPA has improperly developed a CO standard that boilers must meet at all times based on 3 run stack tests with no acknowledgment of the highly variable nature of CO emissions in solid fueled boilers. EPA has collected a limited amount of 30-day CO CEMS data, but has collected much more CO stack test data. CO emissions from boilers can be highly variable, especially when fuel mix and load change. Facilities are typically required to conduct stack tests at least 80 percent of full load during normal operating conditions. Therefore, a CO stack test is going to represent the best operation of any boiler. A stack test run on a high load assumes that if a unit meets the standard at high load it will also meet it at low load. Additionally, stack tests run on a concentration basis are not reflective of the full-operating range. EPA has used only 3-run stack test data, which represents only a small snapshot in time captured during the best operating conditions, to set emission limits for a pollutant that is highly variable.

Using short-term test data to identify 'best performers' and then set a 30-day average emission limit based on the short-term data suffers from three significant shortcomings:

1. Best performers should be those units having the lowest long-term average CO emission rates, not those with the lowest 3-hour test averages.

2. The majority of the best performers have a single Method 10 test which provides almost no information on CO temporal variability.

3. Short-term tests do not reflect startup, shutdown, or malfunction conditions, nor do they capture fluctuations in emissions due to load swings, fuel quality changes, or changes in fuel mix (in multi-fuel boilers). (Neglecting for the moment that CIBO recommends use of a work practice for SSM periods).

EPA states that it obtained CEMS data from best performing units and used this data in establishing the standards. EPA further states that these periods are predictable and routine and it believes it is appropriate to have the same standards apply during startup and shutdown as applied to normal operation.

EPA has not established in the record that these statements and conclusions are true. The MACT floor standards were derived entirely from CO performance test (3-runs) data. While EPA did attempt to address variability by gathering 30 days of CO CEMS data from five boilers, it did not utilize this data other than to conclude that only the two biomass boilers showed an inverse relationship of CO to boiler load (see page 9 of the MACT floor memorandum) and to conclude that the statistical methodology using solely performance test data was appropriate.

CIBO notes that not all these data sets include periods of startup. In the stoker coal subcategory, the unit at DuPont in West Virginia did not note any periods of SSM in the CO Monitoring Template. Further, EPA's graph of the CO CEMS data plotted vs boiler load for the Phillip Morris boiler in Virginia (the only pulverized coal boiler with CEMS data in EPA's dataset) (see Appendix B-1 of the MACT floor memorandum) is wrong (it appears to plot the Excel row number vs. CO) and does not include data from boiler load below 100 MMBtu/hr. This boiler went through three startups during the 30 day period and the graph clearly shows elevated CO during low load periods and shows an inverse relationship of CO and boiler load. The average CO concentrations during periods of only "normal" operations was 35 ppm whereas the average CO concentrations during all periods (normal, shutdown, startup) was 27 ppm.

The CO limits proposed for new and existing coal fired boilers > 100 MMBTU/hr are unachievable as stated with normal efficient operation. Re-tuning the boilers to comply with the proposed limit and compliance methodology puts at risk minimization of other non-HAP emission. A much sounder procedure for developing CO emission limits for each subcategory would involve the following steps:

1. Obtain at least several months of hourly CO CEMS data from boilers in the subcategory, and compute the average CO concentration (ppm at 3% O2).

2. Identify the minimum number of five units (or the 12% of units if a higher number) in each subcategory with the lowest long-term averages.

3. Calculate 3 hour block averages and 30-day rolling averages for these best performers.

4. For existing boilers that will determine compliance using EPA Method 10, set a 3-hour average limit equal to the highest 3-hour average in the best performer data set. For existing boilers that will determine compliance based on 30-day rolling averages, set a 30-day average limit equal to the highest 30-day average in the best performer data set. The same procedure could be used to set new source limits using just the CEMS data for the boiler with the lowest long-term average.

Another option CIBO recommends is that in lieu of a set ppm limit for CO and using a CO CEMS to demonstrate continuous compliance, EPA should borrow from the work practice standard. However, instead of tuning to minimize CO, sources would tune to maximize efficiency of combustion over the load range typical of the boiler. The typical load range can be determined using historical plant data or even the load bin-type calculations used in the Part 75 regulations. To ensure continuous compliance with the source could use the CO CEMS to monitor the boiler tune by establishing a typical range of CO for the individual unit immediately after the tune-up.

In summary, for the coal subcategory, EPA has not correctly assessed the impact of normal variability or the impact of startups and shutdowns on 30 day rolling average CO concentrations. In the case of the stoker coal subcategory, no data from startups and shutdowns were included in EPA's analysis. In the case of the pulverized coal subcategory, EPA's analysis erroneously excluded startup periods from the one unit which has CEMS data. Additional data must be gathered before EPA can conclude that a standard based solely on 3-run performance tests can be met by the top performers using a 30 day rolling compliance period either with or without SSM periods included.

D. Basing Floors on Emissions Test Data that is DLL.

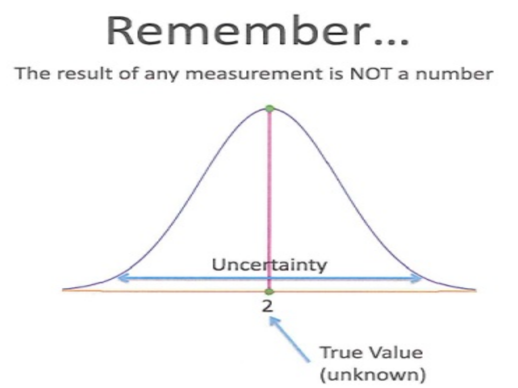
EPA's use of standards at or close to the detection limit introduces an improper bias to setting the MACT floor. EPA acknowledges that data used to support this rule were often reported near or below a test method's pollutant detection capability, and that "the inherent imprecision in the pollutant measurement method has a large influence on the reliability of the data underlying the regulatory floor or beyond-the –floor emissions limit." 75 FR at 32,020. EPA recognizes that when setting a floor emissions limit, "including values at or near the method detection level may not adequately account for data measurement variability." *Id.* Despite recognizing this fact, EPA did not adjust the calculated floor for the data used. *Id.* Rather, EPA proposed a three-step process for defining a "method detection level that is representative of the data used in establishing the floor emissions limits and also minimizes the influence of an outlier test-specific method detection value." 75 FR at 32,201. EPA requested comment on this approach. We believe this approach is unworkable because EPA's fundamental approach to defining the detection level itself is in error.

The test methods used were designed and intended to determine whether a source's emissions of a particular pollutant are above a defined limit. When used for this purpose, the tester calculates the gas sample volume needed to collect the analyte of interest in sufficient mass to: a.) be quantified by the analytical method specified, and b.) demonstrate affirmatively that the emissions measured are less than the specified standard. In the subject test program, sample times and volumes deemed sufficient for the several test methods were specified in EPA Guidance Documents 51-51F. That this approach was less than successful is amply demonstrated by the fact that of the 14 sources tested in the recent ICR and identified as 'best performers', only two sources reported Hg test results as ADL (Above Detection Limits); 3 sources reported ND (Not Detected); 5 sources reported BDL or DLL (Below Detection Limits or Detection Limit Limited); and 4 sources did not report a detection status.[7]

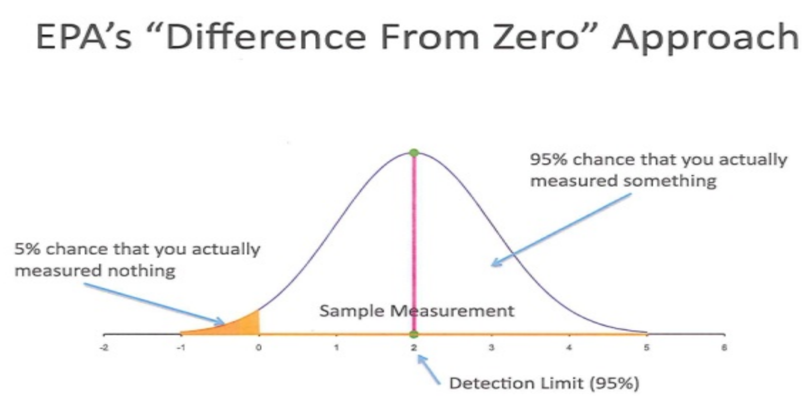
EPA specified that in-stack detection limits (ISDL) be calculated from laboratory detection limits (as 'floor' values) and actual test run data. This approach misrepresents reality in two significant ways. First, EPA defines detection limit as the lowest value differentiable from zero, a departure from the conventional definition of a detection limit as the lowest value differentiable from a blank. Second, EPA's calculation of ISDL ignores the variability in method performance introduced by sampling and related activities, including sample train preparation and recovery. The result of using these unrealistic assumptions to calculate ISDLs are unrealistically and indefensibly low emissions estimates, drawn, as noted above from a series of tests wherein 'ND' is the most common analytical result.

Any measurement actually represents a range of possible values that can be represented by a probability curve; the highest probability (center point) of the curve represents the true value of the measurement:

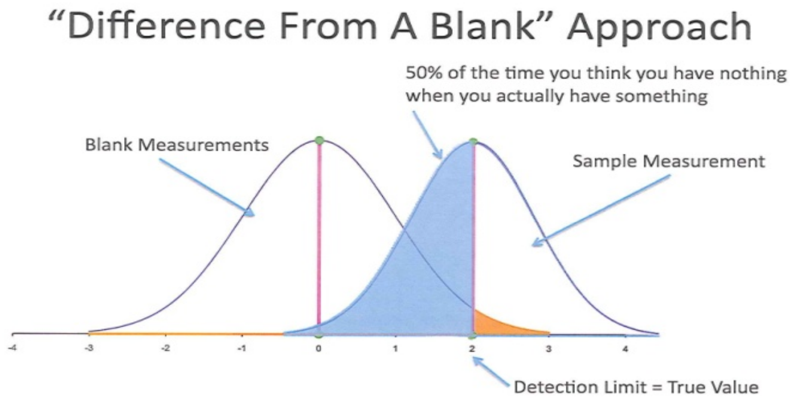
[7] CITE Need to specify which subcategory of sources this refers to, and indicate that the reference is to proposed rule database top performers, not pre-proposal. THIS INFORMATION WILL BE PROVIDED BY BG.



EPA's 'difference from zero' approach to detection limits places the 95% confidence limit of the measurement probability curve at zero. The centerpoint of the curve is the value around which the confidence interval is centered, and thus the putative 'true value' for a statistically significant non-zero measurement, i.e., the detection limit:

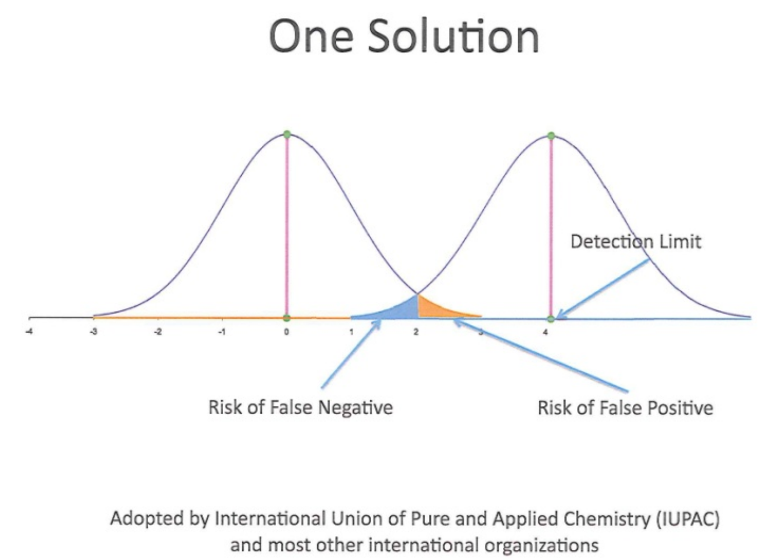


Real world samples exist in matrices which affect the measurement. It is therefore realistic to include a "different from blank" statistic to determine the detection limit. Superimposing the detection limit "statistically greater than zero" curve over a blank "statistically <u>not</u> different from zero" curve gives us this picture:



The detection limit is the point where the blank "statistically zero," meets the measurement "statistically not zero." The large (blue) shaded area, below the detection limit, is the zone where there is a better than even chance that one detects nothing when in fact there is something there. The smaller (yellow) shaded area is the 5% probability zone where one concludes the blank is not zero, when it actually is zero. The sum of these two probability zones poses an interesting problem when one measures near the detection limit: more than half the time, one's answer to the question of whether a measure of something different from zero was taken will be wrong. This problem is resolved by setting the detection limit at 4x the standard deviation of replicate blanks, yielding a 95% confidence interval for "difference from a blank," as shown below.[8] This solution is standard and has been adopted by the International Union of Pure and Applied Chemistry.

[8] Reference to the 95% confidence limit of the measurement probability should not be confused with the 99% confidence limit built into the MACT floors through use of the upper prediction limit (UPL) to account for variability. These are distinct concepts and this discussion should not be read to imply that we accept any confidence limit for the MACT floor lower than EPA's proposed 99%.



In order to establish emission limits at the already low detection levels that EPA proposes, simply correcting unrealistically low lab detection limits will not produce realistic ISDLs; it is also necessary to include sampling method variability. This is done by performing multiple paired-train tests of a source. Paired-train results eliminate source variation, allowing isolation of method variability. An example of using paired-train results:

Measurement A	Measurement B	Difference
30	25	5
25	32	-7
28	30	-2
12	9	3
33	29	4
29	30	-1
27	26	1
	Average:	0.43
	Std. Dev'n:	4.16

From this example, the 95% confidence interval detection limit is the product of the standard deviation of the run-to-run method variance (4.2) and a statistically-based expansion factor determined by the number of samples, ($t_{.975}$, n=7, in this case 2.45), or about 10. For a paired test of runs, the statistical factor is 4.3; for a paired test of 20 runs, the factor is 2.1. More test runs gives a better estimate of method variance, and thus a lower detection limit.

The entire boiler MACT ICR project represented an enormous departure from the way source emissions testers usually work. The process lacked the usual site-specific protocol / agency approval process, agency guidance on data quality, and clear project objectives other than completing some kind of testing prior to the deadline. The result is a great many indeterminate test results, and a very small number of results useful for emissions limits determinations, making the limits determined thereby statistically suspect. As a result, EPA's entire approach, relying as it does on comparing the proposed floor to the detection limit, must be reconsidered. At the very least, all emission test data used for establishing MACT Floors must be thoroughly analyzed and all data from that testing verified to be correct. Analysis of the testing and results needs to include how data relative to detection levels and relative to calibration spans are reported and what emission rates are thereby concluded to be appropriate.

E. Different Statistical Methods are Appropriate For Different Scenarios.

EPA should consider utilizing different statistical methods for different scenarios as appropriate. For example, many of the lowest test results in the database for mercury, HCl, and dioxin/furan, are identified as non-detect, below detection level, or detection level limited. EPA should examine this detection level information and data reporting procedures for consistency and resolve any issues identified so that the test results are compatible and can be used to identify the 'best performers.' For For dioxin, EPA did not have a representative sample of boiler data and even within that they did not have a representative sample of variability. In another example, stack testing run on high load assumes the unit will meet the standard when running on low load and a stack test run on a continuous high load basis is not reflective of the full operating range. EPA should ensure that an appropriate statistical method is used in such cases and not just adopt one method across the board, especially where compliance is based on continuous monitoring.

VI. Subcategories

A. CIBO Strongly Supports EPA's Proposal to Create Subcategories of lndustrial Boilers and Process Heaters.

CIBO strongly supports EPA's proposal to subcategorize industrial boilers and process heaters based on the physical state of the fuel burned. CIBO agrees with EPA's conclusion that "there are significant design and operational differences between units that burn coal, biomass, liquid, and gaseous fuels" and that "[b]oiler systems are designed for specific fuel types and will encounter problems if a fuel with characteristics other than those originally specified is fired." 75 FR 32017. These subcategories therefore reflect significant technological differences with corresponding differences in the nature, composition, and controllability of HAP emissions, as well as the cost of control. CIBO similarly supports EPA's ability to subcategorize further among units firing fuel of the same physical state based on size and extent of use. The design and construction of large and small units reflect further technological differences that affect the nature, composition, and controllability of HAP emissions.

Although CIBO supports EPA's authority and efforts to develop subcategories, the Agency will have to supplement with additional subcategories of industrial boilers and process heaters for the final rule. Specifically, EPA will need to establish additional subcategories for solid fuel units besides those fueled with coal and biomass. It is virtually certain that many secondary materials can be deemed legitimate fuels in accordance with EPA's currently proposed rule for identification of materials that are solid waste. For example, carpet manufacturing scrap appears to meet the criteria for designation as a legitimate fuel. Because such secondary materials are diverse in their compositions, their emissions profiles are also likely to be diverse, and this will need to be considered by EPA in setting emission limits for the additional subcategories.

B. EPA has Abundant Legal Authority to Create Subcategories as Proposed.

EPA has broad discretion to establish subcategories of sources. Section 112 provides EPA with explicit authority "to establish subcategories under this section, as appropriate." § 112(c)(I); *see also* § 112(c)(5) (" ...the Administrator may at any time list additional categories and subcategories of sources[.],,). Indeed, § 112 establishes a presumption in favor of the creation and modification of categories and subcategories in the course of the Agency's regulatory program, by mandating that EPA "shall from time to time, but no less often than every 8 years, revise, if appropriate, in response to public comment or new information, a list of all categories and subcategories of major sources." § 112(c)(I). Section 112(c)(I)'s language empowering EPA "to establish subcategories ... as appropriate" without the inclusion of criteria limiting the Agency's ability to do so confers a broad grant of authority.

The D.C. Circuit previously has interpreted the inclusion of the phrase "as appropriate" in a more limiting statutory mandate as conferring substantial discretion. *Consumer Federation of America v. U.S. Dept. of Health and Human Services*, 83 F.3d 1497 (D.C. Cir. 1996) (*Consumer Federation*). At issue in *Consumer Federation* was a provision of the Clinical Laboratory Improvement Amendments of 1988 (CLIA), which directed HHS to establish qualifications for laboratory technicians that "shall, as appropriate, be different on the basis of the type of examinations and processes being performed." *Consumer Federation*, 83 F.3d at 1503.

The court found that, even though the statutory mandate at issue-using the word "shall"-was phrased in a way generally interpreted to impose a mandatory duty to differentiate qualifications based on different types of tests, the inclusion of the words "as appropriate" removed the mandatory nature of this provision and introduced a significant amount of agency discretion in its implementation. *Consumer Federation*, 83 F.3d 1497. To hold otherwise, concluded the court, would treat the statutory terms "as appropriate" as mere surplussage, thereby violating a basic canon of statutory construction. *Consumer Federation*, 83 F.3d 1497. In the CAA context, the mandate conferred by § 112 to establish subcategories "as appropriate" similarly provides substantial discretion for EPA to create subcategories on any reasonable basis. Nothing in the Act or applicable case law suggests otherwise.

C. EPA Has Broad Discretion to Distinguish Among Classes, Types and Sizes of Sources, Even Within Subcategories.

While EPA has nearly unfettered discretion to create subcategories as appropriate, the CAA provides ample authority for EPA to distinguish among groups of sources within a source category or subcategory in setting a MACT standard. The statute provides that EPA "may distinguish among classes, types and sizes of sources within a category or subcategory" when establishing MACT standards. 42 U.S.C. § 7412(d)(I). Congress's use of the broad terms "class," "type," and "size" shows that EPA is intended to have broad discretion in the appropriate factors that warrant distinguishing among sources, and EPA's proposed subcategories fall squarely within the meaning of "types" and "sizes." It is a well-established canon of statutory construction that courts "give the words of a statute their ordinary, contemporary, common meaning, absent an indication Congress intended them to bear some different import." *Williams v. Taylor*, 529 U.S. 420, 431 (2000) (quotations omitted).

Accordingly, we turn to the standard definitions of "class," "type" and "size." Webster's Third New International Dictionary Unabridged (1993) defines "class" to mean "a group, set or kind marked by common attributes or a common attribute." It defines "type" as "qualities common to a number of individuals that serve to distinguish them as an identifiable class or kind," further clarifying that "[t]ype", "kind" and "sort" are usually "interchangeable and that "kind" in most uses is likely to be very indefinite and involve any criterion of classification whatsoever." To the extent that EPA may distinguish among sources within a category or subcategory on the basis of "any [reasonable] criterion of classification whatsoever," and may create subcategories as appropriate, the CAA strongly supports EPA's authority to create subcategories of industrial boilers as proposed.

1. Congress Contemplated and Approved Subcategorization.

The legislative history makes clear that Congress intended EPA to distinguish among classes, types and sizes of sources under three core circumstances: when differences among sources affect (1) the feasibility of air pollution control technology; (2) the effectiveness of air pollution control technology; and (3) the cost of control: The Senate Report clarifies that the Administrator should: take into account factors such as industrial or commercial category, facility size, type of process and other characteristics of sources which are likely to affect the feasibility and effectiveness of air pollution control technology. Cost and feasibility are factors which may be considered by the Administrator when establishing an emission limitation for a category under section 112. The proper definition of categories, in light of available pollution control technologies, will assure maximum protection of public health and the environment while minimizing costs imposed on the regulated community. However, in limited circumstances where a group of sources may share the characteristics of other sources in the category, the Administrator may establish subcategories for such sources. S. Rep. No. 228, 101st Cong., 1st Sess 166.

Thus, in the view of the Senate, the standard for establishing categories and subcategories is essentially the same, although the Administrator is cautioned not to make too rampant use of subcategories. The House Report similarly provides: "EPA may distinguish among classes, types and sizes of sources within a category or subcategory.... In the determination of MACT for new and existing sources, consideration of cost should be based on an evaluation of the cost of various control options. The Committee expects MACT to be meaningful, so that MACT will require substantial reductions in emissions from uncontrolled levels. However, MACT is not intended to require unsafe control measures, or to drive sources to the brink of shutdown." House Rep. No. 101-490, Part 1, at 328. In sum, while Congress intended the MACT program to achieve significant emissions reductions, it also intended EPA to be cognizant of the costs of control, and to ensure that the program did not cause significant economic hardship. One primary mechanism for achieving this goal is through the use of subcategories; subcategorization enables the Agency to account for the fact that distinctions among classes, types and sizes of sources may have a very real impact on the feasibility of a given control technology, the effectiveness of that control technology, and the cost of control.

2. Variation of Emission Standards on the Basis of Fuel Type is Valid.

The only case to interpret the "classes, types and sizes" language that supports this interpretation. *Sierra Club v. Costle*, 657 F.2d 298 (D.C. Cir. 1981) recognized the broad discretion this language confers on EPA to create what in effect are subcategories of sources with differentiated emission standards. This decision interpreted identical statutory language found in the New Source Performance Standards (NSPS) provisions of § 111 of the CAA. Under the "classes, types and sizes" language, the *Sierra Club v. Costle* court upheld a variable NSPS S02 reduction requirement that was tied to a source's existing S02 emissions levels which, in turn, depended on the sulfur content of the facility's fuel. The Court noted that "[t]he required finding that must underlie a variable standard is much broader than a mere determination that uniformity is not achievable. Rather, EPA has the discretion to vary the standard upon finding that such a departure (from uniform control) does not undermine the basic purposes of the Act." *Sierra Club v. Costle*, 657 F.2d at 321 (quotations omitted). On this basis, the Court expressly upheld EPA's subcategorization of coal-fired power plants based on the sulfur content of fuel, finding that "[the text of the statute nowhere forbids a distinction based on sulfur." *Sierra Club v. Costle*, 657 F.2d at 319.

More generally, the *Sierra Club v. Costle* decision confirms EPA's discretion to set differentiated emissions standards for groups of sources within a category (i.e., for subcategories) even in instances where the strictest standard may be achievable by all sources. The court's analysis in *Sierra Club v. Costle* has obvious relevance to an analysis of the authority granted to EPA through CAA § 112. Section 112 employs the same language as § 111 in defining when EPA may promulgate distinct emission standards for sources within a category or subcategory. The Supreme Court consistently has held that "when administrative and judicial interpretations have settled the meaning of an existing statutory provision, repetition of the same language in a new statute indicates, as a general matter, the intent to incorporate its administrative and judicial interpretations as well." *Bragdon v. Abbott*, 524 U.S. 634, 645 (1998). Therefore, § 112, which adopted § 111's terms almost ten years after the decision in *Sierra Club v. Costle*, must be understood to carry the settled meaning given to those terms by Sierra Club.

3. EPA's Past Practice Regarding Subcategorization is Consistent with the Proposed Subcategories.

EPA's past practice has been consistent with this interpretation of the Act. The Agency has subcategorized sources in numerous industrial categories. From this experience, it is possible to distill several principles that have guided the Agency's decision making with regard to creation of subcategories. First, EPA has determined that subcategorization is appropriate where sources use different processes, and those processes result in different types or concentrations of uncontrolled HAPs. Here, for example, the suite of HAPs emitted by solid-fueled boilers differs from that emitted by liquid-fueled boilers, which in turn differs from that emitted by gas-fueled boilers. For example, the types of metals emitted by solid-fueled boilers differs from the types of metals emitted by liquid-fueled boilers, and gas-fueled boilers typically emit little metals, but may emit more organic HAPs. Thus, subcategorization based on fuel type is appropriate because the different types of boilers emit different types of HAPs. The Agency also has subcategorized sources based on size, where size differences affect the performance of control technologies.

That is also the case here. Thus, subcategorization of boilers based on size, or infrequent utilization, also is consistent with EPA's past precedent and is appropriate because of the impact of these factors on the ability of these sources to maintain the same level of control as larger sources. Furthermore, the Agency has subcategorized sources where differences among sources affect the applicability of control technology. For example, EPA created subcategories in the 1999 polyether polyols production MACT standard, finding "Subcategorization was necessary due to the distinctively different nature of the epoxide and THF processes and its effect on the applicability of controls." Similarly, in the 1998 flexible polyurethane foam production MACT standard, EPA found that "Subcategorization was necessary to reflect major variations in production methods, and/or HAP emissions that affect the applicability of controls." Based on similar rationales, EPA created subcategories in the Group I polymers and resins MACT and the primary aluminum production MACT, and proposed to create subcategories in the polyurethane foam production MACT. Subcategorization based on fuel type is appropriate because the type of fuel affects the applicability of control technology.

EPA also has created subcategories in numerous cases where differences among sources affected the performance of control technology and, hence, the achievability of the MACT standard. For example, in the steel pickling MACT, EPA excluded specialty steel because the technology that is effective for removing acid gas (HCl) emissions from carbon steel manufacturing "may not be as effective" for removing acid gas (H2S04) emissions from specialty steel manufacturing. Similarly, the phosphoric acid manufacturing MACT subcategorized the submerged combustion process and the vacuum evaporation process because the "submerged combustion process is not amenable to the same level of control as is the vacuum evaporation process." In the leather finishing operations MACT, EPA "observed differences in achievable emission levels between the types of leather products produced ... [and therefore] we have established four different performance standards for the various leather products produced." And in the proposed secondary aluminum production MACT, EPA "examined the processes, the process operations, and other factors to determine if separate classes of units, operations, or other criteria have an effect on air emissions from emission sources, or the controllability of those emissions." In sum, EPA's proposed subcategories are amply supported by the language of the statute, the legislative history, applicable case law and the Agency's own past practices.

D. Need limited use subcategory for liquid or gas 2 units based on 10% annual capacity factor or 1,000 hours/year as a threshold.

EPA should establish a subcategory for "limited use" units due to their significant differences from steady-state units. Limited use units should have a rated heat input greater than 10 MMBtu/hr with an annual average capacity factor of 10 percent or less. These units operate for short periods of time during the year and as such may experience relatively little SSM. The short run times would likely exacerbate the effect of startup/shutdown on 30 day averages. Because limited use units do not operate regularly, their emissions differ from average boilers operating for longer periods of time or near their design capacity. EPA has recognized that "units operate most efficiently when operated at or near their design capacity." 75 FR 32023-24. Based on their operating schedule, limited use units may or may not operate at or near their design capacity, but if they do it is for limited periods of time. Considering this, limited use units may operate for a greater percentage of their total operating time inefficiently as compared to steady state units operating near design capacity.

Additionally, the short operating times of limited use units results in difficulties in effectively controlling emissions. As EPA noted in a 2004 response to comments document , based on the operating schedules of limited use units the agency could not identify a control technology for controlling organic HAP emissions. *See* EPA, Response to Public Comments on Proposed Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP, at 67 (Feb. 25, 2004). Considering these differences based on the operating schedule of limited use units, EPA should establish a subcategory for limited use boilers and process heaters. The subcategory should be defined to include units with a capacity utilization factor of 10 percent; or, by a 1,000 hours operating per year threshold.

Furthermore, EPA should adopt a work practices standard for the limited use subcategory. First, EPA's has acknowledged that there is no proven control technology for organic HAP emissions from limited use units. Second, limited use units, such as emergency and backup boilers, cannot be tested effectively due to their limited operating schedules. This is due to the fact that there is often no time to conduct performance tests on a unit operating in a limited capacity and because most EPA test methods require a unit to operate in a steady state. *See* Proposed 40 CFR 63.7520(d). Based on existing test methods, limited use units would have to operate for the sole purpose of being subjected to emissions testing. Such a result is counter to the general intent behind the CAA. EPA should therefore use its authority under section 112(h) and adopt a work practices standard for limited use units and not subject the subcategory to emissions testing or monitoring.

E. EPA Should Create Additional Subcategories.

While CIBO supports EPA's efforts in creating subcategories, EPA has not sufficiently considered the vast array of units and their differences. Units including cyclone-fired boilers do not clearly fit in any of the proposed subcategories. These units vary to such an extent that achieving the emission standard for CO and dioxin/furan in any of the existing subcategories would likely not be feasible. EPA should consider creating a subcategory for units like cyclone-fired boilers that do not fit in other subcategories. Alternatively, EPA should provide clarification as to what subcategory they fall into and the emission standards they are required to meet. Furthermore, CIBO suggests that EPA create subcategories for coal-fired boilers so there is split between units rated at > 1000 MMBtu and units rated at < 1000 MMBtu. EPA should also create a subcategory for fire-tube boilers, including hybrids with water and fire tubes. These units tend to burn biomass and there combustion is so different they should be classified as small.

CIBO also supports EPA subcategorizing for light versus heavy liquid fuels. There are strong technical arguments why EPA should split the liquids into separate sub-categories and not the gases. Fuel gases don't vary much in HAP content with the possible exception of mercury. Liquid fuel HAP contents are likely to vary a good bit with the main division being light (DO) versus heavy (RO)

VII. Units Less Than 10 MMBtu/hr

A. EPA Should Extend Work Practice Standards to Units Less Than 30 MMBtu/hr.

In lieu of emission limits, EPA has proposed work practice standards for existing units that have a design heat input capacity of less than 10 MMBtu/hr. The proposed work practice standard would include the implementation of a "tune-up" program. 75 FR 32012. While CIBO generally supports work practice standards, EPA's decision to limit work practice standards to units less than 10 MMBtu/hr is arbitrarily low. CIBO proposes that EPA extend the work practices standard to boilers and process heaters less than 30 million Btu per hour.

EPA states in the Proposed Rule that units with a design heat input capacity of less than 10 MMBtu/hr generally have stacks with diameters less than 12 inches and that EPA's standard reference methods for measuring emissions are not accurate when applied to such small stacks. 75 FR 32024. EPA estimates that to properly use its standard reference methods to measure the emissions from such units would require expensive modification and retrofits. 75 FR 32024. After conducting a cost analysis, EPA determined under section 112(h) "that it is not feasible to enforce emission standards" for units with a design heat input capacity of less than 10 MMBtu/hr "because of the technological and economic limitations." 75 FR 32024. Based on this conclusion, EPA has proposed a work practice standard instead of emission standards.

While CIBO supports EPA's conclusion to require work practices versus emissions testing, EPA should for the same reason extend the work practice standard to units with a design heat input capacity of less than 30 MMBtu/hr. Many units with heat input capacities between 10 MMBtu/hr and 30 MMBtu/hr experience similar issues and costs that would have a "significant adverse economic impact" on facilities. The cost analysis prepared by EPA was limited to "small units" and the agency did not, but should have, performed a similar cost analysis for subsets of units with heat input capacities greater than 10 MMBtu/hr to determine if further application of work practice standards is justified. In a similar situation, EPA has imposed work practice standards for units with a design heat input capacity of less than 30 MMBtu/hr under the New Source Performance Standards at 40 CFR 60, Subpart Dc. EPA could apply the same rationale here considering many units less than 30 MMBtu/hr do not have the facilities such as test ports and test platforms in place to test for emissions. In addition, small units can have configurations that make such testing very costly, for example, vertical units with the stack located on top of the furnace, convection section, and heat recovery section, thus placing the stack in an inaccessible location. Firetube boilers were considered small units under the prior vacated Subpart DDDDD rule and thus treated differently than large units. EPA has not indicated why the logic used previously is no longer valid for firetube boiler configurations. CIBO believes that many firetube boilers would fall under 30MMBtu/hr heat input and thus this approach of using work practices for units <30MMBtu/hr would be of value to those units.

B. CIBO Supports the Use of CO Monitoring as the Only New Source Work Practice Standard Requirement .

In the preamble to the Proposed Rule, EPA appropriately concluded that process changes or work practices were not appropriate criteria for identifying the MACT floor level of control. It is accurately recognized that metal HAPs are not controlled by the combustion unit, but rather by downstream emissions controls, so that work practices or other Good Combustion Practices (GCP) would not be applicable. CIBO does recognize that CO emissions can be indicative of incomplete combustion and that information can provide guidance for corrective action. The EPA methodology for setting existing and new unit floor requirements appropriately applies continuous CO monitoring to certain new sources.

However, this methodology is applied too broadly, as addressed in other comments below. Boilers and process heaters are critical equipment for industrial facilities and equally critical for commercial and institutional facilities. Operating efficiently and reliability is essential to continued viability and maintaining cost competitiveness. Boilers and process heaters are designed so that high efficiencies can be maintained while keeping uptime as high as possible. These units are extremely diverse in design, fuel input, and operating characteristics, and are required to respond to the demands of the facility or process. Since that is the case, every unit has unique operation and maintenance requirements and training programs to optimize effectiveness for that application. Since industrial boilers and process heaters are so diverse, there are no "common" combustion practice requirements that could assure a certain level of HAP emissions, and EPA correctly determined that none are suitable as a basis for the MACT floor.

Periodic operation of solid fuel boilers in a highly turned down mode is common among several of CIBO's member sectors, as an efficient way to manage manufacturing process energy needs. For example, industrial process boilers in the wood products industry supply steam according to the immediate demand from processes for which they are operated. These boilers operate at widely varying load levels, depending on, among other things, the amount of steam the process equipment is demanding at the time. Because CO emissions may routinely exceed the work practice standard during turndown periods, these periods should be exempt from the CO concentration standard. Importantly, EPA will recognize that during high turndown periods the actual HAP emission load should be lower since the total fuel load is reduced from the normal operation.

High CO emissions are a common occurrence to all solid fuel boilers during high turndown operation due to a combination of well-known combustion fundamentals. Because of these countervailing effects, boilers and process heaters should be subject to the CO concentration limit only when the boiler is operating at greater than 50% of its design capacity. While averaging time can provide some latitude for those conditions, imposition of the CO limit under low loads is not appropriate. EPA has recognized boiler, or burner, turndown ratio as a factor affecting performance in several contexts. See, EPA, Final Technical Support Document for HWC MACT Standards, Vol. IV, p. 3.6 (July 1999); EPA Region 6 Center for Combustion Science and Engineering, Hazardous Waste Combustion Unit Permitting Manual, Component 1 How to Review a Test Burn Plan, p. D-5.5 (Tetra Tech Jan. 1998). EPA provided this limitation of CO limit applicability at or above 50% rated capacity in the prior vacated Boiler MACT rule. The recently proposed Boiler Area Source Rule also includes this limitation of the CO emission concentration limit to operation at or above 50% of rated capacity. Therefore, a similar provision should also be included in this rule for new and existing units.

CIBO also believes that continuous CO monitoring is not required in order to demonstrate low organic HAP emissions, especially for gas 2 (other gaseous-fired) units. The cost of CO CEMs is a very significant cost for small affected sources, considering that there are really no emissions reductions associated with installation of the CEM. A periodic test is adequate for smaller units, but continuous CO monitors could be justified for large units.

VIII. Gas 1 Approach

A. Work Practice Approach is Appropriate.

The Gas 1 subcategory includes boilers and process heaters that burn at least 90 percent natural gas and/or refinery gas on an annual heat input basis. 75 FR 32017. EPA proposes to adopt work practices versus numeric HAP emissions limitations for new and existing units in the Gas 1 subcategory and in the Metal Process Furnace subcategory. 75 FR 32012. CIBO agrees that this is the correct approach for EPA. It is not technically or economically feasible to control HAPs from these units; therefore, EPA should proceed under section 112(h) and adopt work practices for these units in the final rule.

CIBO supports EPA's proposal to require work practices for all small new and existing boilers and process heaters with a heat input capacity of less than 10 MMBtu/hr in lieu of emission limits given the difficulty in testing units of that size as well as the significant costs associated with testing and monitoring. In addition, CIBO supports EPA's proposal for work practices for new and existing larger boilers and process heaters burning natural gas in lieu of emission limits. As EPA notes in the preamble, section 112(h) of the CAA allows EPA to set work practice standards in situations where "it is not feasible in the judgment of the Administrator to prescribe or enforce an emission standard . . . ." The definition of "not feasible to prescribe or enforce an emission standard" is defined in the CAA as any situation where "the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations." EPA's explanation of the physical limitations of the boiler and process heater stacks as well as the considerable cost associated with installing the necessary testing platforms and test ports clearly meets the criteria for work practice standards under section 112(h) for these sources. There are other testing challenges and data problems that justify section 112(h) work practices for larger natural gas-fired boilers/process heaters as well as significant policy reasons for why emission limits are not appropriate for these larger sources.

For units larger than 100 MMBtu/hr, EPA explains that "the capital costs estimated for installing controls on these boilers and process heaters to comply with MACT limits for the five HAP groups is over $14 billion." 75 FR 32025. While CIBO agrees with EPA's decision to act under section 112(h), the $14 billion figure grossly underestimates the cost of add-on controls by excluding the monitoring and operating expenses associated with such equipment. Other industry groups filing comments on this proposal have estimated that the capital cost of add-on controls for natural gas-fired units in EPA's database alone would be upwards of $50 billion for the subcategory. In reality, this number is likely even higher given that EPA's database does not include all the natural gas units in the country that would be affected by this rule and this estimate assumed that controls can be installed and that they can actually achieve the emission limits contemplated by EPA. If replacement of the combustion units was required, costs would be even higher unless production was shut down, and that presents another whole set of negative economic impacts.

B. Testing Challenges for Natural Gas-Fired Boilers Over 10 MMBtu/hr Meet the Criteria for Section 112(h) Work Practices.

EPA has requested comment on whether the application of measurement methodology to natural gas-fired boilers and process heaters is impracticable due to technological or economic limitations. The data collected by EPA during the ICR process clearly demonstrate the challenges associated with testing of natural gas-fired boilers. Natural gas is a very clean, low-HAP fuel, which means that testing of these units results in data that are close to detection limits or the quantitation capability of EPA's test methods. For example, some of the lowest HAP levels for the units in the database for the Gas 1 subcategory are detected at levels considerably lower than undetectable levels achieved in other tests. This demonstrates that the lowest levels and detection limits are not reproducible. Furthermore, the levels of HAP emitted by gas-fired units in the database are extremely low, and in some cases are undistinguishable from ambient air near the lowest detect levels. The sample results, therefore, are more likely "noise" than numbers representing actual emissions. Given the technical limitations of EPA test methods when used with such a low-HAP fuel, it is appropriate, based on the criteria in § 112(h), that EPA impose work practices for new and existing units in the Gas 1 subcategory and in the Metal Process Furnace subcategory.

Such low HAP emissions also support EPA taking a harder look at delisting major source natural gas-fired boilers and process heaters under section 112(c)(9) of the CAA. As noted above, the ICR data indicate that HAP emissions from natural gas-fired boilers are often at or below the detection level for EPA test methods or at ambient air levels. In addition, as noted earlier, EPA has determined in the rulemaking applicable to boilers at area sources that natural gas-fired units do not emit any mercury, arsenic, beryllium, cadmium, lead, chromium, manganese, nickel, POM (as 7-PAH), ethylene dioxide, and PCB, and therefore, regulation of those sources are not necessary to meet the 90% requirement in 112(c)(3). Given that HAP levels for natural gas-fired units likely meet the threshold requirements in section 112(c)(9), CIBO recommends that EPA seriously consider undertaking the process for delisting these low-HAP sources, or at the very least, delist units that are under a certain heat input capacity, e.g., less than 100 MMBtu/hr.

C. Work Practices for Natural Gas-Fired Boilers Over 10 MMBtu/hr Will Encourage the use of Cleaner Fuels.

In further justifying the work practice standard, EPA notes that requiring the same emission control system for Gas 1 units as those units using other fuel types might provide a disincentive for switching to natural gas as a control technique. 75 FR 32025. The proposed work practices approach for natural gas boilers/process heaters eliminates the disincentive that would be created by stringent emissions limits that penalize the low-HAP emissions of this fuel. As noted earlier in these comments and as demonstrated by EPA's database for this rulemaking, natural gas-fired boilers and process heaters have some of the lowest HAP emissions and therefore pose very low risk. Consequently, many facilities already have expended large amounts of capital switching from "dirtier fuels" to natural gas as a means to minimize regulatory concerns.

For example, the conversion of a number of coal-fired boilers to burn natural gas (with some having fuel oil back-up and/or ability to burn landfill gas as well) over the last 20 years has helped areas comply with new, more stringent National Ambient Air Quality Standards (NAAQS). For facilities that have not converted, stringent emission limits that necessitate costly add-on controls will discourage further conversions to lower HAP fuels. Specifically, if both coal-fired boilers and natural gas-fired boilers are subject to stringent emission limits and require costly add-on controls for purposes of complying with the limits, coal will be more attractive given the historically low price of that fuel. Furthermore, add-on controls will decrease boiler efficiency and increase fuel consumption. These are "absurd results" that run contrary to EPA's efforts to encourage industry to increase energy efficiency and move to cleaner, lower-polluting fuels. These policy considerations further bolster EPA's decision to impose work practices on larger natural gas-fired boilers and process heaters.

Additionally, EPA failed to include in its calculation the fact that fuel-based emissions, such as mercury and HCl, can only reasonably be addressed by the addition of controls on natural gas suppliers. However, considering these factors should only further justify EPA's decision to adopt a work practice standard as the MACT standard for new and existing units in the Gas 1 subcategory and in the Metal Process Furnace subcategory. CIBO agrees with EPA's assessment under section 112(h) and EPA should avoid establishing any numerical emission limits for these units in the final rule.

D. Emission Limits for Natural Gas-Fired Boilers/Process Heaters are Not Feasible and EPA Should Extend the Gas 1 Work Practices Approach to the Gas 2 Subcategory.

As discussed above, CIBO agrees with EPA's proposed approach to institute work practices for new and existing units in the Gas 1 subcategory and in the Metal Process Furnace subcategory. Emission limits for units burning natural gas are not feasible given the challenges associated with testing units with such low HAP emissions. Such an approach also would be a significant policy shift from how EPA treated these sources in the earlier Boiler MACT promulgated in 2004 and how EPA has treated natural gas-fired units in other rules.

For example, when EPA made the finding under § 112(n)(1)(A) that the regulation of electric utility steam generating units (EGUs) under § 112 is appropriate and necessary, the agency specifically determined that natural gas-fired EGUs were not included in the listing because the HAP emissions from these units "were negligible based on the results of [EPA's utility Report to Congress]." In fact, in the section of EPA's notice of finding and listing of EGUs under section 112, EPA notes that "[c]onversion of coal- and oil-fired units to natural gas firing effectively eliminates HAP emissions." Furthermore, in the NESHAP for Stationary Combustion Turbines, Subpart YYYY, EPA does not impose emission limits on existing units from any of the subcategories, including natural gas-fired units. Finally, as noted earlier, in EPA's area source proposal for boilers, natural gas-fired units are excluded from that rule because they do not emit the HAPs of concern and they are not needed to meet the 90% HAP reduction requirement in the statute. As these examples demonstrate, setting emission limits for natural gas-fired units would be a significant departure from how EPA has treated this fuel under section 112 in other rules.

The discussion above explaining why work practices are justified for natural gas-fired boilers and process heaters also serves to demonstrate why the data in the database are not reliable for setting emission standards for this subcategory of units. Given the very low-HAP emissions from natural gas-fired units, testing of these units results in data that are below or close to the detection limits for EPA's test methods or beyond the quantitation capability of these tests. Thus, the data in the database are not reliable and not reproducible because the data often times represents noise as opposed to actual emissions data.

CIBO also doubts whether EPA has performed a thorough Quality Assurance/Quality Control (QA/QC) review of the database itself. The background document in the docket providing EPA's floor analyses for the potential Gas 1 floors in the preamble indicates that EPA included in its analysis direct-fired process heaters, which are not supposed to be included in the rule. Specifically, EPA included a direct-fired rod/bar mill furnace, CORockyMtnSteel212, among the natural gas-fired units comprising the floors for HCl, CO and D/F. According to the owner and operator of the Rocky Mountain Steel unit, the unit is a direct-fired re-heat furnace where steel billet intermediate product comes into direct contact with the products of combustion. This explains why the test data for the unit shows such low CO and D/F levels. Such database errors call into question whether EPA has included the correct units in the database used to set the MACT floors in the proposal and whether EPA has undertaken the necessary QA/QC of the database.

Another serious concern with the emission limits included in the preamble is that the MACT floor analysis performed by EPA for natural gas-fired boilers and process heaters is severely flawed. EPA has used a pollutant-by-pollutant or HAP-by-HAP analysis that relies on a different set of best performing sources for each separate HAP standard. EPA applied the same approach in the New Source Performance Standards and Emission Guidelines for Hospital/Medical/Infectious Waste Incinerators (HMIWI), which are currently being challenged before the D.C. Circuit. This "cherry picking" of the best data in setting each standard disregards the sources from which the data are gathered and results in a hypothetical set of best performing sources rather than the actual performance of one or more real sources.

In fact, the database shows that no one particular facility in the Gas 1 subcategory can meet all five of the emission limits simultaneously. Moreover, the sources in the database indicate that there is no demonstrated control technology that would allow units to meet the HAP limits in the rule or no unique characteristics that explain why certain units can achieve lower emissions levels than other units. Furthermore, units that drive the floors have no vendor guarantees or add-on control technologies for HAP. Thus, there is no pathway identified for compliance. Basing emission limits on the data for the subcategory, therefore, is arbitrary, capricious and an abuse of discretion.

In addition, EPA's floor-setting approach is flawed and inconsistent with the statute in that it ignores the requirement in section 112(d)(1), (2), and (3) to base emission standards on the performance of "sources" in the category or subcategory and that EPA's discretion in setting such standards is limited to distinguishing among classes, types, and sizes of sources. These provisions of section 112(d) make clear that standards must be based on actual sources and cannot be the product of HAP-by-HAP parsing that results in a set of composite standards that do not reflect the overall performance of any actual source in the subcategory. Congress provided express limits on EPA's authority to parse units and sources for purposes of setting standards under section 112 and that express authority does not include the ability for EPA to distinguish units and sources by individual pollutants as is proposed in this rule. Thus, EPA's floor approach and MACT floors themselves are arbitrary, capricious and an abuse of EPA's discretion.

Additionally, EPA's approach to subcategorizing the boilers and process heaters in the Gas 1 subcategory for purposes of establishing the potential floors in the preamble fails to account for units designed and operated to minimize emissions of NOx to comply with state and federal permit limits. Units operated to keep NOx levels low will have higher emissions of CO due to the need to minimize excess air to minimize thermal NOx. Thus, CO emissions from these units will be higher than boilers not designed or operated to keep their NOx emissions low and in compliance with permit limits. The CO floor level in the preamble for Gas 1 units ignores these design issues and any emission limits based on the potential CO floor level in the preamble would be difficult, if not near impossible, for these boilers to achieve while also meeting the required NOx permit limits. EPA has discretion to account for design characteristics when setting floors and should do so if work practices are not used.

In light of the problems with the database and the difficulties and challenges with testing and setting standards for natural gas-fired boilers/process heaters explained above, EPA is more than justified in proposing section 112(h) work practice standards for these units. Such an alternative standard is consistent with the statute's authorization for EPA to substitute section 112(h) standards in those cases where "the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations."

IX. Gas 2 Approach

The Gas 2 subcategory as defined in the Proposed Rule includes "any boiler or process heater that burns gaseous fuels other than natural gas and/or refinery gas not combined with any solid or liquid fuels." 75 FR 32065. The arguments presented above regarding natural gas and/or refinery gas apply to all gases and EPA should extend the work practice standard to Gas 2 units as it is not technically or economically feasible to control HAPs from Gas 2 units.

A. Problems with the Gas 2 approach.

As with the Gas 1 subcategory, it is not technically nor economically feasible to control HAPs from Gas 2 units. Many of the same reasons justifying a section 112(h) work practice for the Gas 1 subcategory apply to the Gas 2 subcategory as well. As a preliminary matter, there is no real difference between Gas 2 and Gas 1 units for certain types of gases. Additionally, as indicated above, EPA did not take into account in the establishment of the Gas 2 MACT Floors the extreme diversity of Gas2 fuels and the units in which they are combusted. EPA identifies only 196 Gas 2 units, and this is known to be grossly understated. The Gas 2 MACT Floor units present a significant number of issues relative to the representativeness of those units to the overall population as well as major issues with the basic emissions data itself. Examples of these issues follow. *See* Excel file - EPA MACT Floor, App C,D,E.xls and supporting information.

HCl Top 12% Performers (only one unit)

1. LAShellChemicaGeismar – Furnace F-S801 – 1989 vintage 190MMBtu/hr natural gas fired process heater burning vent gas. EPA lists average HCl emissions of 1.7E-6 lb/MMBtu, which is the average of the 3 reported runs. However, all three runs reported emissions below the DL. Six different fuels are shown as being routinely fed to the combustion unit. They include: heavy bleed (heavy recycle), LP Vent Flow to Utilities (Syngas), P & D Regen Gas, Hotwell Vent (Secondary Fuel Gas), C-S520 Vent gas, AO/ID Inert Vents. These fuels are obviously unique to the processes at that location, and not indicative or representative of the many diverse process fuels utilized by industry. HCl emissions from this unit are 2 orders of magnitude lower than any other emissions data for Gas 2 units, thus supporting the unique nature of the gases combusted in that unit. In addition, information from Shell in response to an API request indicates that this unit was firing >17% liquid fuel (heavy recycle), 33% process gas, and 50% natural gas during the emissions test, thus disqualifying this unit from use as a top performer for establishing the Gas 2 PM MACT Floor. The emissions test report only provides total heat duty, not differentiated by specific fuel type.

Hg Top 12% Performers (only one unit)

1. SCBMWManufacturingCo – HB03 – 1993 vintage natural gas and landfill gas fired package watertube boiler with LNB and no other APCD, DHI= 61MMBtu/hr. LFG HHV noted to be 544 Btu/scf. EPA lists average HCl emissions of 8.25E-8 lb/MMBtu, which is the average of the 3 reported runs, but all runs are listed as DLL. It appears per the emission test report that only the one fraction detected above the DL (HCl fraction) was reported in the main report, and thus carried over to the EPA emission rate. It appears the non-reported DL quantities for the other 4 fractions would total about 3x the reported quantity. Thus the reported Hg emission rate is underreported per EPA ICR Phase 2 instructions. A single unit burning LFG again is not representative of the many various gases fired in units in the Gas 2 subcategory.

D/F Top 12% Performers (only one unit)

1. SCBMWManufacturingCo – HB03 – 1993 vintage natural gas and landfill gas fired package watertube boiler with LNB and no other APCD, DHI= 61MMBtu/hr. LFG HHV noted to be 544 Btu/scf. EPA lists average D/F emissions as 0.002669 ng/dscm TEQ, which is the average of the 3 reported runs, but all runs are listed as DLL. A single unit burning LFG again is not representative of the many various gases fired in units in the Gas 2 subcategory.

PM Top 12% Performers

1. LAShellChemicaGeismar – Furnace F-S801 – 1989 vintage natural gas and liquid fired 190MMBtu/hr process heater burning vent gas and other fuels. EPA lists average PM emissions of 0.00042 lb/MMBtu, which is the average of the 3 reported runs. Six different fuels are shown as being routinely fed to the combustion unit. They include: heavy bleed (heavy recycle), LP Vent Flow to Utilities (Syngas), P & D Regen Gas,

Hotwell Vent (Secondary Fuel Gas), C-S520 Vent gas, AO/ID Inert Vents. These fuels are obviously unique to the processes at that location, and not indicative or representative of the many diverse process fuels utilized by industry. In addition, information from Shell in response to an API request indicates that this unit was firing >17% liquid fuel (heavy recycle), 33% process gas, and 50% natural gas during the emissions test, thus disqualifying this unit from use as a top performer for establishing the Gas 2 PM MACT Floor. The emissions test report only provides total heat duty, not differentiated by specific fuel type.

2. WIGPGreenBay2818 – B29 – Fluidized Bed Boiler #9 – 1982 vintage fluidized bed boiler with dry limestone injection and fabric filter listed as firing coke oven gas, DHI= 486MMBtu/hr. EPA lists average PM emissions of 0.00042 lb/MMBtu, which is the average of the 3 reported runs from 9/21/07. A FBC boiler with limestone injection and a baghouse firing coke oven gas is in no way representative of the diverse process off-gases burned in Gas 2 units. However, GA Pacific indicated that this unit is actually firing pet coke, not coke oven gas. Therefore, this unit should not be used to establish the Gas 2 PM MACT Floor.

CO Top 12% Performers

1. LAShellChemicaGeismar – Furnace F-S801 – 1989 vintage natural gas fired 190MMBtu/hr process heater burning vent gas. EPA lists average CO emissions of 0.0128 ppm @3%O2 dry, which is the average of the reported runs, however, all are below DL. Six different fuels are shown as being routinely fed to the combustion unit. They include: heavy bleed (heavy recycle), LP Vent Flow to Utilities (Syngas), P & D Regen Gas, Hotwell Vent (Secondary Fuel Gas), C-S520 Vent gas, AO/ID Inert Vents. These fuels are obviously unique to the processes at that location, and not indicative or representative of the many diverse process fuels utilized by industry. In addition, information from Shell in response to an API request indicates that this unit was firing >17% liquid fuel (heavy recycle), 33% process gas, and 50% natural gas during the emissions test, thus disqualifying this unit from use as a top performer for establishing the Gas 2 PM MACT Floor. The emissions test report only provides total heat duty, not differentiated by specific fuel type.

2. TXEquistarChemicals – UTBLRG- 1969 vintage package watertube boiler with LNB and no other APCD, DHI= 272MMBtu/hr. Natural gas and process gas fired. EPA lists average CO emissions of 0.0128 ppm @3%O2 dry. The emission spreadsheet provides ug/dscm and EPA converted it in the Access database. The emissions test report is not provided in the EPA support data to allow evaluation of the M10 analyzer calibration span for the tests. However, for a CO level of 0.02 ppm, it is highly likely that the calibration upscale span was too high to allow for M10 accuracy. In addition, there is no information on the process gas quality or the percent of heat input from natural gas vs process gas.

3. TXFlintHillsPortArthur – LOUBOILER10 – 1978 vintage package watertube boiler with steam/water injection, no other APCD, DHI= 231MMBtu/hr. Fuel is a varying mix of petrochemical process gas and natural gas. EPA lists average CO emissions of 0.08 ppm

@3%O2 dry. Two runs indicated emissions below DL of 0.1 ppm, with the third run at 0.04 ppm. Process gas HHV is given as 814 Btu/scf.

4. TXEquistarChannelview – F38001A and B – 1974 vintage steam superheaters firing process gas through floor burner with no APCD, DHI= 172MMBtu/hr. EPA lists average combined firing CO emissions of 0.1 ppm @3%O2 dry. Emissions for all 3 runs indicate below DL of 0.1 ppm. The emissions test report for these tests is not provided.

5. TXFlintHillsPortArthur – LOUBOILER9 – 1978 vintage package watertube boiler with steam/water injection, no other APCD, DHI= 231MMBtu/hr. Fuel is a varying mix of petrochemical process gas and natural gas. EPA lists average CO emissions of 0.1 ppm @3%O2 dry. All three runs indicated emissions below DL of 0.1 ppm. Process gas HHV is given as 814 Btu/scf.

6. TXLyondellChannelview – F6101 – 1986 vintage process heater with LNB firing process gas, DHI= 46MMBtu/hr. EPA lists average CO emissions of 0.1 ppm @3%O2 dry. All three runs indicated emissions below DL of 0.1 ppm. Emission test report is not provided in the EPA reference information.

7. TXLyondellChannelview – F6105 – 1989 vintage process heater with LNB firing process gas, DHI= 48MMBtu/hr. EPA lists average CO emissions of 0.1 ppm @3%O2 dry. All three runs indicated emissions below DL of 0.1 ppm. Emission test report is not provided in the EPA reference information.

8. TXEquistarChannelview – F4601 – 1974 vintage process heater with no APCD firing process gas, DHI= 12MMBtu/hr. EPA lists average CO emissions of 0.11 ppm @3%O2 dry. All three runs indicated emissions below DL of 0.11 ppm.

Therefore, if EPA were to promulgate MACT Floor emission limits for Gas 2 units, it is obvious that major revisions would be needed to the approach taken and the floors determined. It needs to be recognized that if extremely low emission limits are imposed on Gas 2 combustion, many units currently combusting that fuel with the attendant heat recovery would simply stop burning that fuel and instead flare it. Flaring that additional process gas will result in increased use of fossil fuel, increased criteria pollutant emissions, and increased GHG emissions, all contrary to recognized energy and environmental program goals.

B. EPA should allow other gases to be considered Gas 1.

Other gases that fall within the Gas 2 subcategory should be able to fall under the Gas 1 subcategory if certain criteria are met. For example, thresholds could be set related to minimum HHV, whether combustion of a gaseous stream is self-sustaining, percent composition, or maximum contaminant levels. If a gas other than natural gas/refinery gas meets the criteria, then it should be subject to the same work practice standards and included in the Gas 1 subcategory. There is very little difference between the emissions from top performers in the Gas 2 subcategory as compared to the Gas 1 subcategory; therefore, EPA should simply create one gas-fired subcategory.

Chemical process off-gas is an example that should be treated as Gas 1 with a work practice standard. CIBO believes that process off-gases derived from natural gas or petrochemical feedstocks that have low heating values due to their hydrogen content also provide useful combustion energy and should be treated similarly to Gas 1 units. These process gases provide stable combustion characteristics and typically have low contaminant content due to the nature of the processes. The EPA hydrogen fueled flare document- *Basis and Purpose Document on Specifications For Hydrogen-Fueled Flares,* Emission Standards Division, U.S. Environmental Protection Agency Office of Air Radiation, Office of Air Quality Planning Standards, March 1998, documents the basis for establishing minimum hydrogen content for unsupported flare combustion. The testing documented established the minimum hydrogen content of 8% by volume as that proven adequate for sustained combustion without support fuel (nonassisted flare operation).

As noted in the document, hydrogen has a lower heat content than organics commonly combusted in flares meeting the prior existing flare specifications and cannot, therefore, be used to satisfy prior control requirements. However, since the combustion of hydrogen is different than the combustion of organics, and the test report demonstrates a destruction efficiency greater than 98 percent, the EPA believes that hydrogen-fueled flares meeting the recommended specifications will achieve a control efficiency of 98 percent or greater. This level of control is equivalent to the level of control achieved by flares meeting the prior existing specifications. In addition to achieving the same destruction efficiency of VOC or organic HAP, these recommended specifications have the added advantage of reducing the formation of secondary pollutants; since the combustion of supplemental fuel would not be required by hydrogen-fueled flares to meet the existing flare specifications.

In another example, EPA does not have enough data on combustion of anaerobic digester gas to differentiate it from natural gas. As such, classification of anaerobic digester gas as Gas 2 is unreasonable. The use of digester gas is being promoted as a way of preventing emissions of potent methane GHGs from wastewater treatment plants, to minimize sludge production and as a way to conserve natural gas usage. The use of digester gas would not be expected to cause an increase in any HAPs. Any potential increase in SO2 emissions is readily controlled by conventional means. If digester gas combustion causes a unit to be regulated under Gas 2, the gas will likely not be burned in boilers or process heaters and will instead be flared resulting in an increase in fuel usage and emissions.

Therefore, CIBO recommends a similar approach be used to establish 8% by volume as a minimum hydrogen content in hydrogen fueled process gases as a criterion that allows its use as a fuel in boilers and process heaters under the Boiler MACT rule and allow consideration as Gas 1 with a work practice MACT approach.

C. EPA's Proposed Definition of Gas 2 Units is Flawed.

EPA's proposed definition for Gas 2 units does not include *de minimus* threshold. Therefore, under the Proposed Rule *any* use of gas other than natural gas or refinery gas will result in the imposition of emissions limits instead of work practices for the gas fired unit. Such a result is unreasonable and will result in the decreased use of off-gas and landfill gas. EPA has recently promoted the use of these alternative gases; therefore, such a result is clearly not in keeping with the agency's overall goals and policy.

D. Inconsistencies Relative to use of Landfill Gas.

The Proposed Rule includes the definition of units designed to burn gas 2 as follows:

> Unit designed to burn gas 2 (other) subcategory includes any boiler or process heater that burns gaseous fuels other than natural gas and/or refinery gas not combined with any solid or liquid fuels.

Therefore, per this definition, a boiler or process heater firing any percentage of heat input of landfill gas (LFG) would be considered as a gas 2 unit and subject to all Proposed Rule requirements for gas 2, including the emission limits. These onerous requirements are basically at odds with the intentions of the EPA Landfill Methane Outreach Program (LMOP). As stated on the EPA web site:

> The U.S. Environmental Protection Agency's Landfill Methane Outreach Program (LMOP) is a voluntary assistance program that helps to reduce methane emissions from landfills by encouraging the recovery and beneficial use of landfill gas (LFG) as an energy resource. LFG contains methane, a potent greenhouse gas that can be captured and used to fuel power plants, manufacturing facilities, vehicles, homes, and more. (Reference: http://www.epa.gov/lmop/)

Many facilities with affected sources under this rule have implemented projects to burn LFG in boilers and process heaters, some in concert with the EPA LMOP program. While the actual analysis of LFG may vary over time and between landfills, the general composition is well known by EPA to contain methane, CO2, nitrogen, hydrogen, argon/oxygen, and other trace constituents with a HHV of around 500 Btu/scf. HAP emissions from LFG combustion are not known to be a problem, and in fact, the top performing gas 2 unit for mercury one of the top performing units for D/F was the BMW watertube boiler firing LFG. There is no assurance that other units combusting LFG can achieve those limits due to landfill and combustion unit variability. In addition, the gas 2 emission limits also include an unrealistically low CO limit of 1ppmvd @ 3%O2 that likely cannot be achieved by any boiler or process heater firing any percentage of LFG. For example, one CIBO member package boiler demonstrated CO emissions when firing 27% LFG with natural gas that were more than 2.5x that seen when firing natural gas alone (55 ppm vs 21 ppm both at 3%O2), with a 20% reduction in NOx emissions with the LFG. It is likely that other units would see similar impacts on CO with combustion of LFG. Imposition of the proposed emission limits on units firing LFG will very likely result in a cessation of beneficial burning of LFG in boilers and process heaters for two reasons: first, and most importantly, there is no assurance that all emission limits can be achieved even with application of emissions control technology; and second, installation of emissions controls in an attempt to meet the proposed limits will be prohibitively expensive compared to simply stopping combustion of LFG and instead increase use of natural gas. Thus this Proposed Rule will stop the LMOP program in its tracks relative to use of LFG as boiler and process heater fuel; result in increased criteria pollutant emissions; and result in increased GHG emissions due to flaring of the LFG and alternative use of increased natural gas. CIBO instead recommends that EPA recognize the environmental benefits of using LFG and treat LFG as gas 1 with use of a work practice approach.

X. New Source MACT Floor

A. Limitations of the New Unit MACT floor Determination.

EPA has proposed a pollutant by pollutant approach for establishing emission limits for new sources. This approach is unworkable, primarily because EPA has set the limits for new sources based on the levels of individual pollutants achieved by the best performing source in the category. The end result is that standards for new sources are established based on a hypothetical boiler able to meet the emission limits for all pollutants. None of the top performers EPA relied on in setting the emission limit for a given pollutant are capable of meeting the new unit emission limits for all pollutants.

Because EPA has based its emission standards on a boiler not in existence, it cannot possibly be similar to any existing or new boiler. Therefore, imposing such standards is simply unreasonable and unsupportable. To impose standards on all new units, EPA must identify a best performing similar source in each subcategory that can actually attain all of the proposed emissions limits simultaneously. The approach EPA has taken will have a catastrophic effect on the industry and the U.S. economy. Vendors will not guarantee the performance required under the rule and no new biomass, coal, or CISWI boilers will be built.

Additionally, it is critical for EPA to consider the range of fuels that a new unit might actually use when establishing the MACT Floor for new units. EPA correctly states that for fuel dependent HAP emissions, they need to determine what the best controlled sources has achieved in light of the inherent and unavoidable variations to the HAP content of the fuel that such unit might potentially use (75FR32028). However, while EPA may identify an existing source in its present location that is the best performing similar source, the new boiler and process ether limits apply to units that can be located anywhere in the US, not only at the location of the best performing similar source. Therefore, it is incumbent on EPA to evaluate the full range of potential fuels that might be used by new sources if located anywhere in the US, and not just the variability of fuel for the best performing unit (notably EPA did not even evaluate fuel variability for some pollutants/subcategories). This level of fuel variability analysis and consideration has not been done by EPA and is a serious omission that directly impacts the achievability of the standard by any new units. EPA must correct this deficiency.

B. Additional subcategories are needed for new source standards.

The proposed new source standards are unrealistic and, if left unchanged, could seriously endanger the nation's long-term prospects for growth in the manufacturing sector. Reports we hear from suppliers of boilers and air pollution control systems are that they will not be able to supply commercial guarantees to meet the proposed standards. Additional subcategories which focus on the regional fuel supplies (Powder River Basin, Illinois Basin, Central Appalachian, etc) are needed to allow future boilers to be installed across the nation. For example, the top performer used to set the HCl standard for new coal-fired boilers is a boiler which burn sub-bituminous coal, which inherently has much lower chlorine content than eastern coals. A facility on the east coast should not have to meet standards that can be met only by burning a fuel only obtained from hundreds if not thousands of miles away.

In lieu of emission limits, EPA has proposed work practice standards for existing units that have a design heat input capacity of less than 10 MMBtu/hr. The proposed work practice standard would include the implementation of a "tune-up" program. 75 FR 32012. EPA should not require numerical emission limits for new units that have a design heat input capacity of less than 10 MMBtu/hr. Instead, EPA should treat both existing and new units similarily, by extending work practices to new units with a design heat input capacity of less than 10 MMBtu/hr.

C. Consider use of a Percent Reduction Approach

EPA should consider other options for establishing new source emission limits. One example that EPA could adopt is the percent reduction approach. Such an approach has been utilized by EPA in other situations and has long-standing legal precedent, including the ICI Boiler NSPS Subpart Db. The mechanism currently in use permits the source to select between a limit or percent reduction. This approach can help resolve the problem of highly variable content of fuels, among even the same type of fuel. This approach is particularly suited to HCl and Hg emissions. EPA would obviously need to consider proper subcategorization relative to control efficiencies that differ depending on the combustion unit and fuel types. But this approach is feasible and could provide significant flexibility.

XI. Alternative Existing Unit Floor Basis

Similar to the new unit approach noted above, existing unit subcategories could also use a percent reduction option for HCl and Hg as an alternative to an emission limit.

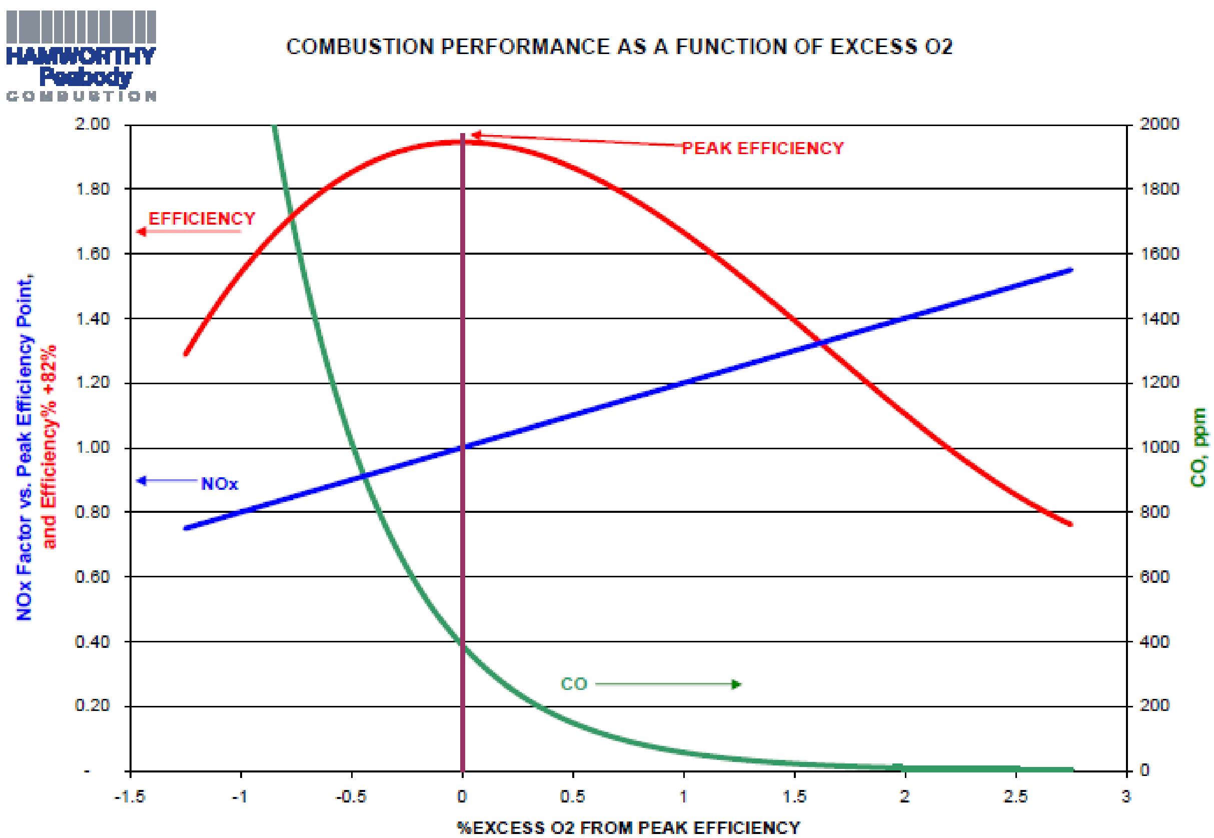
XII. Tune-Ups

EPA has relied on its authority under CAA section 112(h) to impose a work practice standard in lieu of MACT emission limits. EPA is proposing tune-ups as the work practice standard for the control of HAP emissions. 75 FR 32014. While as a general matter CIBO supports EPA's exercise of its 112(h) authority to impose work practice standards in lieu of emission limits, we recommend the following changes to the proposed tune-up requirements.

A. Tune-ups are defined to minimize CO, but that will decrease efficiency and will increase overall emissions.

In the Proposed Rule, the tune-up requirements are defined in such a way to reduce CO emissions without any consideration of efficiency and costs. 75 FR 32014. Specifically, the Proposed Rule requires minimization of CO "consistent with the manufacturer's specifications." 75 FR 32014. This practice generally requires increasing excess air, temperature, costs, and even overall HAP emissions while decreasing efficiency. Additionally, lowering CO emissions for many units will result in an increase of NOx emissions. First, many units are so old, there will be no manufacturer's specifications. Second, many units perform periodic tune-ups to minimize NOx as part of RACT requirements. It is well known that CO and NOx emissions are generally inversely related.

Hamworthy Peabody Combustion (a CIBO member) provided the figure below to indicate the general relationship of (excess O2 from peak efficiency), CO, NOx, and combustion efficiency for a gas fired burner. This shows relative changes from the peak efficiency point and is generally applicable in form for all fuels. As shown, attempts to focus on reducing CO emissions will lead to increased excess air operation, thereby increasing NOx emissions and decreasing unit efficiency. EPA has failed to recognize this basic reality of burner operation and the negative impact on NOx and energy efficiency, and rather, in their impacts analysis, assumed a 1% improvement in efficiency (75 FR 32037). While there may be units in operation that can improve efficiency, well tuned boilers and process heaters will generally increase NOx emissions and decrease efficiency if the only focus is on reducing CO emissions. In reality, optimum conditions are achieved with CO at some higher level. CIBO recommends that EPA amend the rule so that tune-ups also consider optimizing efficiency, limiting increases of NOx, and ensuring safety, not focusing on minimizing CO. In fact, EPA is correct in its definition of "Tune-up" in that it specifies "to optimize combustion efficiency" (63.7575). In contrast, 63.7540(a)(10)(iv) stipulates "minimize total emissions of CO." The latter needs to be changed to recognize the need for optimization in recognition of all appropriate factors.



Furthermore, EPA should acknowledge that portable combustion analyzers are acceptable. Proposed § 63.7540(a)(10)(v) requires measurement of the CO & O2 concentration in the effluent stream. 75 FR 32059. EPA should specify it is permissible to use a portable electrochemical analyzer that meets EPA Method CTM-034. This will measure CO, O2, & NOx from stationary combustion sources. This would be a less expensive method of determining the CO concentration than having to hire a testing contractor and many facilities already utilize portable analyzers.

B. Tune-up Scheduling Should Be Amended.

EPA has proposed that units conduct tune-ups between 10 to 12 months following completion of the previous tune-up. This essentially requires tune-ups to be conducted more frequently then on an annual basis. This is unreasonable as it does not incorporate the requisite flexibility for units. Allowing this flexibility is especially important for process heaters that run for extended periods (i.e. 2 to 5 years) so that internal inspections cannot be done annually.

CIBO supports amending the Proposed Rule so that tune-up frequencies are relaxed to once every 5 years for units smaller than 10 MMBtu/hr and to biennially for units over 10 MMBtu/hr. One problem with requiring annual tune-ups is that this requirement is likely to interfere with scheduled maintenance outages and force a shutdown earlier than otherwise needed. Also, some units are not used continuously and the requirement should be changed to require these tune-ups after so many operating hours, rather than so much elapsed time. EPA could modify the Proposed Rule to allow tune-ups to be done in conjunction with normal inspections and/or overhaul schedules. In order to determine applicability, EPA could require unit specific demonstration of extended operating times. If a unit is not operated for a period of time, EPA should provide that tune-ups be relative to elapsed operating time.

C. Tune-ups Should Not Require Outside Certification of Adjustments.

Tune-up is defined in the Proposed Rule as "adjustments made to a boiler in accordance with procedures supplied by the manufacturer (*or an approved specialist*) to optimize the combustion efficiency." 75 FR 32065 (emphasis added). This definition limits the ability of an owner/operator to make adjustments to those that are done in accordance with procedures supplied by manufacturers or approved specialists. EPA should revise this to allow the owner/operator to establish and conduct appropriate procedures independent of this outside certification process. Many facilities have in-house specialists who are well-qualified to conduct optimization adjustments on units. In fact, in-house specialists have site specific information compared to the generic, and possibly in appropriate recommendations a manufacturer might provide. Many adjustments are not directly applicable to some units, particularly some process heaters. Therefore, all steps included in 63.7540(a)(10) should be qualified to only be used when appropriate for specific units. Generic procedures recommended by manufacturers and "approved specialists" will not always result in the appropriate adjustments and EPA should recognize and allow use of the knowledgeable resources currently available in-house at many facilities and companies.

D. Tune-ups are Inapplicable For Some Units.

As currently proposed, EPA's tune-up requirements are unworkable for certain units to which they apply. EPA should amend the work practice standards to reflect these discrepancies. Specifically, the tune-up procedures require owners and operators to inspect "the system controlling the air-to-fuel ration, and ensure that it is correctly calibrated and functioning properly." 75 FR 32014. This requirement is simply inapplicable to units that utilize metered fuel-air control systems with continuous excess air (O2) control where combustion is optimized continuously. On these units, EPA should recognize that system inspections, equipment calibrations, and operational checks are sufficient to ensure the system is "calibrated and functioning properly." Flexibility is what is needed, and EPA should incorporate in the tune-up requirements room for sources to utilize or modify procedures as applicable for and as needed to optimize specific units based on their design and operation.

XIII. Fuel Analysis

A. EPA Should Provide a Fuel Analysis Option for Gas and Liquid Fuels.

EPA has provided in the Proposed Rule that boilers and process heaters may choose to demonstrate compliance with emission standards on the basis of fuel analysis. 75 FR 32014. While CIBO supports a fuel analysis option, there are additional units that should be able demonstrate compliance in this way and there is clarification that is needed. While CIBO supports a fuel analysis alternative, the methods provided in the Proposed Rule are predominantly geared towards solid fuels. EPA should provide a fuel analysis option for gas and liquid fuels to the extent the final rule imposes emission limits, recognizing the inherent differences between gas, liquid, and solid fuels.

B. EPA Should Clarify Definition of Units Burning Single Type of Fuel.

Units that burn a single fuel and choose to comply via stack testing are not required to conduct fuel analyses. 75 FR 32051. This exemption from performing fuel analysis is not clear and the definition of units burning single fuel needs to be revised. CIBO recommends that EPA define "units burning a single type of fuel" to include those that burn only one type of solid fuel but use gaseous or liquid fuel as start-up/supplemental fuels.

Most solid fuel boilers cannot start up from a cold condition on their main fuel. Such units require an additional fuel source to initiate combustion until such time as the unit is warmed up and stable combustion with the solid fuel can be safely maintained. For example, pulverized coal fired boilers typically start up by firing either Natural Gas or Fuel Oil. Startup periods typically last from several hours (e.g. stoker coal or pulverized coal boilers) to several days (e.g. large circulating fluidized bed boilers), per OEM recommendations, during which time coal combustion is started. When certain OEM specified conditions are met (e.g., minimum steam temperature, minimum tube temperature, minimum flue gas temperature, minimum pulverizer temperature, elapsed time from light-off, etc.), the start up fuel is shut down and the unit fires coal exclusively. Some pulverized coal units have additional OEM specified flame stability controls that require the start up fuel to be fired on specific burners when a pulverizer is either being removed from service or put into service (e.g., typical pulverized coal fired boilers). Solid fueled units can also utilize the startup fuel to preserve unit capacity due to an unforeseen malfunction in the solid fuel feeding and/or firing system(s). Whether for startup, short-term flame stability when solid fuel feeding and/or firing systems are taken in- or out-of-service, or in reaction to unusual conditions, the startup or supplemental fuel is a transient fuel source. The start up or supplemental fuel represents a negligible percentage of the source's total hours of operation, and thus has a negligible impact on overall emissions from the source. For example, if a source operates continuously on coal for 49 weeks per calendar year; and has three start ups per year, each of which requires firing Natural Gas for 8 hours; the annual source operating time on Natural Gas equals (3 x 8 hours = 24 hours) divided by (49 weeks x 7 days per week x 24 hours per day = 8,232 hours) equaling 0.3% of the source's operating hours on the startup fuel. The percentage of operating hours with supplemental fuel will necessarily vary based on unit design, operating characteristics, fuel quality, and other issues.

We support EPA's intent to exempt units that fire a single type of fuel from the additional burden of conducting fuel analyses during performance stack testing as a reasonable accommodation to minimize unnecessary costs. EPA should clarify its intent in this matter by including language to explain that units which require a start-up fuel for initial startup, units shutdown, or transient flame stability purposes, still qualify as "sources that burn a single type of fuel" and are exempt from the fuel analysis requirements under §63.7521 and Table 6.

EPA should further clarify that solid fuel units that fire Natural Gas or Commercial Fuel Oil as a supplementary or start up fuel are likewise considered "sources that burn a single type of fuel" and are exempt from the fuel analysis requirements under §63.7521 and Table 6.

Additionally, § 63.7540(a) does not appear to recognize the provisions set forth in § 63.7510 that exempt units that fire a single fuel from conducting fuel analyses during performance stack testing. Additional provisions should be included in this section to recognize the exemption from fuel analysis testing during performance stack testing in § 63.7510 for units that fire a single type of fuel.

1. Clarification of Equation 7.

EPA requires that during performance testing for HCl, sources must determine "the fraction of the total heat input for each fuel type burned (Qi) based on the fuel mixture that has the highest content of chlorine, and the average chlorine concentration of each fuel type burned (Ci)." 75 FR 32057. The "maximum chlorine input level" must be determined using "Equation 7". 75 FR 32057. The definition given for Qi is unclear. EPA should clarify Equation 7 and the explanation given for Qi (i.e. "the fraction of total heat input from fuel type."). 75 FR 32057.

2. Units Cannot Obtain the Worst Case Fuel During Emissions Testing.

The Proposed Rule requires that units required to demonstrate compliance via stack testing must conduct fuel analysis to establish maximum fuel pollutant input levels. 75 FR 32057. This "worst-case fuel" requirement is unreasonable. EPA's theory apparently is that the owner or operator will be able to procure a worst-case fuel that will maximize the fuel chlorine, mercury and/or total selected metals content without exceeding the Emission Limitation in Table 1. In fact, EPA suggests in §63.7520 that the owner or operator may have to conduct more than one performance test to accomplish this. The iterative process by which an owner or operator must search for fuels and then conduct performance tests until the worst-case fuel is found will be very time consuming and expensive and is unnecessary.

The same result can be accomplished by requiring the owner or operator to perform the initial performance test using the same fuel that has typically been fired in each boiler. The results of the performance test can then be used to prorate the actual chlorine, mercury and/or total selected metals content of the fuel to the worst-case conditions that would meet the emission limits. The owner or operator would then simply have to maintain the fuel chlorine, mercury and/or total selected metals content below the prorated values established during initial performance test, regardless of the fuel supplier. A new performance test could then be required if the fuel chlorine, mercury, and/or total selected metals content exceeded the prorated values established during the performance test.

C. Fuel Quality Limits Should Not Be Established Based on Quality During Initial Performance Test.

Under the Proposed Rule, fuel quality limits are established based on quality during the initial performance test. This approach is unreasonable and does not take into account the inherent variability of fuels. EPA should allow units to establish an operating limit based on extrapolation from fuel content correlated with emissions test data up to the emission limit. Further, EPA should allow units that choose to comply with emissions standards by continuous monitoring (e.g. Mercury CEMS) to avoid setting a fuel quality limit for that monitored constituent, given that continuous monitoring would ensure greater confidence that actual stack emissions are within acceptable limits. Additionally, EPA should allow units to conduct fuel supplier sampling and/or analysis and on-site sampling on a monthly composite sample basis. On-site sampling standards could be established similar to those found in the original MACT rule. The standards contained in that rule included processes for collecting samples and statistical analysis of fuel.

While on-site sampling is appropriate for some units, it is not appropriate for others. Specifically, biomass and some coal units often have large numbers of suppliers and sampling could be burdensome if applied to every new supplier. Therefore, EPA should provide that biomass units need only one representative sample from the fuel pile and that coal units obtain one sample per coal type, not per supplier.

Additionally, according to the Proposed Rule, units that burn a Gas 1 gas in combination with other fuel types do not have to conduct monthly sampling/analysis of the Gas 1 gas under any circumstances. However, it appears that units classified in categories other than a Gas 1 unit are required to routinely sample/analyze all fuel types burned in the unit. This would include non-Gas 1 units that burn some amount of natural gas and refinery gas. Such a requirement would be unreasonable. First, natural gas suppliers generally do not perform a broad spectrum of analysis of the gas supplied. Furthermore, there are only a handful of laboratories in the United States that are capable of conducting analysis of pipeline natural gas. Simply put, the routine analysis of pipeline natural gas would be a complicated process and it should be specifically noted to not be required.

XIV. Liquid Fired Units

A. Definition of Units Designed to Burn Oil Should Be Amended.

The proposed definition of the subcategory of "units designed to burn oil." needs to be clarified. In the Proposed Rule, EPA defines the subcategory of "units designed to burn oil." as follows:

> Unit designed to burn oil subcategory includes any boiler or process heater that burns any liquid fuel, but less than 10 percent solid fuel on a heat input basis on an annual average, either alone or in combination with gaseous fuels. Gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment, gas supply emergencies or for periodic testing of liquid fuel not to exceed a combined total of 48 hours during any calendar year are not included in this definition. 75 FR 32065.

The proposed definition is unreasonable because, as it is currently phrased, gaseous fuel boilers and process heaters could be limited to only 48 combined total hours during a calendar year before they are included in this subcategory. EPA should clarify the "units designed to burn oil" subcategory to apply only to the time the unit is operated on oil for periodic testing of oil firing capability. EPA should impose no time limit on legitimate gas curtailment or gas supply emergencies. Such a change would be reasonable and better reflect EPA's intent for units that burn liquid as evidenced by the "gas-fired boiler" definition in the Proposed Area Source Rule. 75 FR 31931.

In the Proposed Area Source Rule, EPA defines gas-fired boiler as "any boiler that burns gaseous fuels not combined with any solid fuels, burns liquid fuel only during periods of gas curtailment, gas supply emergencies, or periodic testing on liquid fuel. Periodic testing of liquid fuel shall not exceed a combined total of 48 hours during any calendar year." 75 FR 31931. Notably, EPA imposes the 48 hour limitation only on the "[p]eriodic testing of liquid fuel" and there is no limit on legitimate gas curtailment or gas supply emergencies. Beyond consistency with the Proposed Area Source Rule, this rectification of the definition would be similar to EPA's approach in the stationary SI internal combustion engine ("ICE") NSPS, where 50 hours are allowed for non-emergency use. *See* 40 C.F.R. 60.4243.

B. CIBO Recommends that EPA Expand the Definition of Gaseous Fuel Fired Boilers and Process Heaters to Include Periods of Gas Curtailment when Backup Liquid Fuel Must be Fired.

Federal, state, or local governments and gas suppliers have in the past required a facility to curtail its use of natural gas so that it can be used for home heating or another critical need. The length of the curtailment usually lasts a very short time period during which the facility may either restrict production or switch to a liquid fuel to maintain the same level of production. These occurrences will only be taken in the national interest or for regional or local emergency type situations and only for a short time period. Onsite gas supply emergencies could also occur whereby use of gas fuel is not possible and backup liquid fuel firing is required in order to maintain critical production or services. Periods of backup fuel use would be limited to the time to complete repairs and safely return the gaseous fuel system to service.

CIBO requests that EPA expand the definition of gaseous fuel-fired boilers and process heaters to include gas curtailment required by a government agency (federal, state, local), natural gas supplier, or on-site gaseous fuel system emergencies. During the limited time of curtailment when the facility switches from gas to backup liquid fuel (recommended to be limited to 876 hours per year (10%)), new or reconstructed boiler and process heater affected sources would be exempt from complying with the liquid fuel standards (if they are included in the final rule). The exemption should allow for periodic backup fuel operation and testing in order to prove that it is available and reliable should it be needed; that testing time should be included within the 876-hour limit. In addition, this 10% annual time allowance would also allow for periodic operation on oil to allow turnover of oil in the storage tank to prevent oil degradation that might impact reliability when needed in an emergency. A facility should be able to apply to the permitting authority for an extension of the 876-hour exclusion if curtailments cause the unit to exceed that time limit.

Documentation of time firing backup fuel should be provided to the permitting authority by the affected source as part of the semi-annual reporting requirement. A review of California rules (i.e., Ventura County Rule 74.15; Kern Rule 435.2; Bay Area Rule 9.7; Santa Barbara Count Rule 342; Yolo-Solana Rule 2.27; South Coast Rule 1146; and SCAWMD Rule 1109) shows substantial relaxation of requirements in recognition of natural gas curtailments. Each of the California rules provides for less stringent limits when a normally gas-fired unit burns liquids - during a curtailment and while testing to assure operability on liquids in case a curtailment should occur.

If there is a curtailment of natural gas because of National interest, it is important as part of our National Energy Policy that refineries and petrochemical plants be allowed to continue production at the pre- curtailment levels so that there is a sufficient supply of home heating oil, jet fuel, diesel, gasoline, feedstocks, etc. If facilities are forced to limit production, the reduction in supplies may further intensify the problem because of the reduction in supply of products such as home heating oil, diesel, jet fuel, and gasoline. Similar issues exist at other critical manufacturing facilities.

The exemption would enable the facility to operate under the pre- curtailment gaseous fuel compliance requirements and thus be excluded from the liquid fuel requirements. Further, new or reconstructed units would not be required to install pollution control equipment required for liquid fuels which may never be used or only used for a very short time period over many years.

C. Issues with Data used to Establish the Liquid MACT Floors.

There are several issues and problems with units identified as top performers for establishing the liquid MACT Floors, including for example, use of combustion units that are not representative of most units in the subcategory, and lack of fuel quality data that can be correlated with emissions test data for many sources, thus preventing adequate fuel variability analysis and allowance. Examples of these are indicated below in a summary for each top performer. *See* Excel file- EPA MACT Floor, App C,D,E.xls.

HCl Top 12% Performers

1. The Liquid floor for HCl contains 94 boilers, with only 5 using emissions data. The other 89 are using fuel data. CTElectric Boat EMU 18 is using a fuel based emission factor for CTElectric Boat EMU 17. CTElectric Boat EMU 17 actually has emissions data and, using that data, EMU 17 is ranked 96th. The multiple NCCampLejeuneMCB boilers (88 boilers) who are tied for 7th all use the same fuel based emission factor from the fuel data for NCCampLejeuneMCB C-AS-4151-16. NCCampLejeuneMCB C-AS-4151-16 has

emissions data and, using that data, C-AS-4151-16 is ranked 186. Neither NCCampLejeuneMCB C-AS-4151-16 nor CTElectric Boat EMU 17 are in the floor rankings, where other boilers on their respective facilities are in the floor using their fuel data. The logic used for this approach is not apparent and has not been explained, but would appear to influence statistical calculations.

2. INUSSteelGaryWorks- Unit O4B10459: DHI= 500MMBtu/hr. During tests firing 13% heavy liquid, 4% gas 1, 83% gas 2 (blast furnace gas). No emissions controls. No liquid fuel analysis data. 3 test runs averaged 0.000207 lb/MMBtu (0.000233; 0.000188; 0.000199).

3. SCMilliken-Dewey- Unit D30: Top performer- all three runs were BDL with reported emission at <0.0001 lb/MMBtu (therefore, no variability). Watertube boiler- DHI= 10.46MMBtu/hr. Unit burns 100% anhydrides waste liquid. Liquid analysis indicated <400 ppm Cl (BDL) and HHV of 25,764 Btu/lb (vs No.2 Oil at ~19,200 and No.6 Oil at ~18,200 Btu/lb. Unit ran at only 4.3MMBtu/hr during the tests (41%). This fuel is in no way representative of typical fuel oils used by the preponderance of liquid fired boilers and process heaters

4. VAINVISTAWaynesboro- 2-205 (V#1) Vaporizer #1: Dowtherm® Vaporizer (process heater) DHI= 43MMBtu/hr. No.6 Oil fired. 2008 emission test averaged 0.000243 lb/MMBtu (0.000315; 0.000207; 0.000208). Noted in the database as having a FF- known to not be the case- it has no control; most likely data is confused with PC fired Boiler 2, which does have a baghouse/FF. No fuel quality data. Vaporizer 2 emission test showed HCl emissions of 0.05 lb/hr. If operated at 43MMBtu/hr heat input, that would be 0.0012 lb/MMBtu. It is likely the heat input was also confused with Boiler 2 heat input of 168MMBtu/hr during its test (actually, the emission test spreadsheet gives steam output for the vaporizer during those tests of 166.04, 166.1, and 167.37Mpph- which is not applicable to a vaporizer). Since M26A was used, it is logical that the M5 results for that day correspond to the HCl results- the PM data gives what appear again to be boiler heat inputs that average 168.1MMBtu/hr. Dividing 0.05 lb/hr by 168.1 gives 0.000297 lb/MMBtu- very close to the above indicated emission test results. Therefore, the reported and utilized emission rate for this unit is at least 3.9x too low (168.1 / 43MMBtu/hr DHI)- actual heat input during the test was not provided for that unit, so it should be no higher than 43MMBtu/hr.

5. ILCognisCorp- Boiler #2- Ranked #2 by EPA based on chlorine (in fuel)- 1948 vintage field erected watertube boiler, DHI= 67.3MMBtu/hr. EPA is using fuel chlorine data for the MACT Floor list. Both Boilers 1 and 2 fire natural gas and waste vegetable oil as fuel per the emissions test report. Light liquid listed, but all analyses for that company are listed as animal fats/tallow or vegetable oil. (No analyses provided for fuel oil). Twelve liquid analyses provided, with Cl ranging from 0.036% to 0.13%, and HHV ranging from 13,900 to 21,300 Btu/lb. EPA listed equivalent HCl emissions for that unit is 4.74E-6 lb/MMBtu, however the EPA calculation is not correct. For example, the analysis at 0.078% and 19,100 Btu/lb is shown by EPA to be 4.4E-6 lb/MMBtu, but calculation by Cl percent and Btu/lb and 36/35 for HCl/Cl MW gives 0.042 lb/MMBtu. This error applies to all of that unit's analyses. Correct average equivalent HCl emission

rate based on the fuel analysis data and 100% emission is 0.045 lb/MMBtu. This emission rate would put this unit above all others in the database, not in the top performers. In addition, emissions test data for Boiler 1 was provided for testing conducted during the time the liquid analyses were provided indicating an HCl emission rate of 0.005542 lb/MMBtu, ranking #186 in the EPA MACT Floor list. Fuel firing during that test consisted of 80% light liquid and 20% natural gas. Thus while natural gas cofiring would be expected to dilute the HCl emission rate leading to lower HCl emissions, even the measured emission rate is three orders of magnitude higher than the EPA listed fuel equivalent emission rate. So there are a number of problems with this unit being used as a top performer: a) Waste vegetable oil in no way is representative of all liquids fired in units subject to the rule, and certainly is not representative of fuel oils, b) EPA determined fuel equivalent HCl emission rate is incorrect (erroneously low), c) even the reported emission data for one of the units while cofiring the waste vegetable oil with natural gas places the unit as a worst performer.

Hg Top 12% Performers

1. The Liquid floor for Hg contains 41 boilers, with only 11 boilers using emissions data. The other 30 are using fuel data. CTElectric Boat EMU 17 and CTElectric Boat EMU 18 are both using fuel data from CTElectric Boat EMU 17, even though there are emissions data available for CTElectric Boat EMU 17. This emissions data would make CTElectric Boat EMU 17 one of the highest ranked boilers. The same case applies for the 29 TNMilanArmyAmmunitionPlant boilers. They are all using the fuel data for TNMilanArmyAmmunitionPlant D88L-1, Source #27-0010-86, even though emissions data exists for this specific boiler. Once again, by using this emission test data, TNMilanArmyAmmunitionPlant D88L-1, Source #27-0010-86 would be one of the top ranked boilers.

2. MNGPDuluth – EU33 Boiler #3 – 1971 vintage firetube boiler, DHI= 43MMBtu/hr, with ESP that is common to 2 other similar size boilers. Fuel analyses are available for the three emissions tests when firing No.6 Oil. Reported Hg content 0.8, 0.9, 1.0 mg/kg (ppm), with oil HHV of 18,000-18,200 Btu/lb, giving equivalent input Hg emissions of 50 lb/Tbtu. Reported emissions test results are 9.66E-8, 4.34E-8, 3.59E-8 lb/MMBtu, or an average of 0.06 lb/TBtu. All three emissions tests are identified as DLL by EPA, and <PRL per the emission test report. It is highly questionable that Hg emissions are reduced by 99.9% in this unit, yet EPA does not appear to even identify this as a potential issue. In addition, the emission test was done with only Boiler 3 in operation, and the other two boilers obviously bleeding in air to the ESP upstream of the emission test point, since tested O2 was >16% and CO2 was 4.0-4.6%, with flue gas temperature of approximately 235F. For all three emissions tests, the reported Hg emissions were only based on the fractions of the M29 train that detected Hg above the DL, e.g., Run 1 reported <0.15 ug/dscm when only 2 fractions detected 0.07 and 0.08; Run 2 only reported the single fraction detecting 0.07, and Run 3 reported the single fraction detecting 0.06. Therefore, none of the three emissions test results were reported per the EPA directions that all fractions be reported at the DL. Thus, the reported results are falsely low for this unit that is a top performer.

3. MEFPLEnergyWyman – Unit #5 – 1977 vintage firetube boiler, DHI = 72MMBtu/hr, with no APCD. No.6 Oil firing. 12 oil samples all from 10/5-6/09. Average equivalent Hg content based on sample analysis = 29.6 lb/TBtu. Emission rate per emissions test average identified as 0.086 lb/TBtu. However, it appears there may be some inconsistencies in spreadsheet fuel analysis data vs the lab test report, and the oil Hg level appears to be < DL. In any case, there is a tremendous difference between apparent oil Hg level and emissions test level, raising a big question whether emission test results are falsely low.

4. ILCognisCorp – Boiler #2 & #1 – Both ranked #3 – 1948 vintage field erected watertube boiler with no APCD, DHI= 67.3MMBtu/hr. EPA is using fuel data for the MACT Floor list. Both Boilers 1 and 2 fire natural gas and waste vegetable oil as fuel per the emissions test report. Light liquid listed, but all analyses for that company are for animal fats/tallow or vegetable oil. (No analyses provided for fuel oil). Twelve liquid analyses provided, with all Hg analyses listed as ND (detection level not noted). Emissions test data for only Boiler 1 was provided for testing conducted during the time the liquid analyses were provided indicating an Hg emission rate of 1.063E-7 lb/MMBtu, with EPA listing emissions for both Boilers 1 and 2 at 1.09E-7 lb/MMBtu and a co-ranking of #3 in the EPA MACT Floor list. Fuel firing during that test consisted of 80% light liquid and 20% natural gas. Natural gas cofiring would be expected to dilute the Hg emission rate leading to lower Hg emissions than liquid firing only. Waste vegetable oil in no way is representative of all liquids fired in units subject to the rule, and certainly is not representative of fuel oils. In addition, since Hg in the liquid fuel was ND, there is no way to account for fuel quality variability for this unit.

5. PABoeingRidleyPark – 033 – 1967 vintage firetube boiler with no APCD, DHI= 42MMBtu/hr. No.6 Oil fired. All fuel analyses indicated <0.1 mg/kg (ppm). All three test runs were DLL, but data was correctly summed using detected levels and detected quantities. However, with no quantitative fuel Hg levels, no ability to account for fuel variability, plus oil was fired for the three tests from a single tank with no deliveries during the period. Oil sulfur level was not provided in the analyses, but the permitted SO_2 emission rate is 1 lb/MMBtu, or about 0.9% S in oil.

6. NYConEd59thStStationNewYork – Boiler 118 – 1972 vintage watertube boiler, DHI= 180MMBtu/hr firing No.6 Oil with no APCD. EPA lists Hg emission rate as 1.39E-7 lb/MMBtu. The reference test data does not indicate any Hg emissions test data for Boiler 118, but does list 13 oil analyses data sets (EPA apparently used 12 of those since data was not inserted correctly for one analysis). All of the analyses indicate the Hg content to be below detection limit. EPA uses the detection limit indicated for each analysis and the HHV for each analysis to calculate equivalent Hg as lb/MMBtu. EPA correctly calculates the equivalent lb/MMBtu for each individual analysis on that basis, but appears to calculate the average incorrectly. The correct average of the 12 analyses is 1.64E-6 lb/MMBtu, and the correct average for all 13 analyses is 1.65E-6 lb/MMBtu, recognizing that the average is in all cases based on Hg detection limit in the oil.

7. SCMilliken-Dewey – D30 – 1965 vintage package firetube boiler with no APCD, DHI= 10.46MMBtu/hr. Fuel during boiler emissions test identified as Liquid Tetramer

Byproduct from Anhydrides Process. 12 fuel sample analyses were provided, with all indicating Hg content of < 0.1 ppm, thus below that detection limit. Average HHV for the liquid for the 12 analyses was 25,064 Btu/lb; so at that detection limit, equivalent fuel Hg would be 4 lb/TBtu. All three emissions tests were identified as DLL with the average emission rate given as 3.2E-7 lb/MMBtu, matching the value in the EPA MACT Floor table. Heat input during the test was 3.5MMBtu/hr. All of the fractions of the M29 train were identified as being below detection limit. However, in the emissions test report and appendices, it appears that the reported back half emissions only include the H2O2/HNO3 fraction and not the other three fractions. If those were included, the reported total back half would be <1.8ug instead of <0.7ug. Therefore, reported emissions are low by at least 2.5x. Therefore, reported emissions for this unit are incorrectly low based on required EPA emissions test reporting for the Phase 2 ICR, and this fuel is in no way representative of typical fuel oils used by the preponderance of liquid fired boilers and process heaters.

8. NJVinelandMuniElectric-HowardDown – Unit 9 – 1960 vintage field erected 180Mpph watertube boiler with multiclone (indicates it to likely be a prior coal fired boiler). DHI= 207MMBtu/hr, No.6 Oil fired. The emission test report for Unit 9 appears to indicate that Hg emission fractions used for determining the Hg emission rate only used those fractions which were detected above the detection level. However, in this case, it appears that EPA corrected the emission rate to include those fractions at their detection levels. Seven oil analyses were provided, but all indicated Hg concentration below the 0.1 ppm detection level.

9. MESDWarrenSomerset – Package Boiler – 1989 vintage package boiler, DHI= 71MMBtu/hr. No emissions tests appear to be provided for this boiler. Appears that EPA used No.6 Oil analysis data to determine equivalent Hg emission rate. 15 total analyses provided, 8 of which were >DL, with those averaging about 4.5E-7 lb/MMBtu. Other analyses were <DL of 0.005 ppm. Including those DL values as well with an average HHV gives a value close to the EPA figure of 3.92E-7. Range of Hg for analyses >DL was 0.005 – 0.015 ppm. Note that 0.015 ppm is equivalent to about 8.1E-7 or twice the emission rate assigned to this unit.

10. INUSSteelGaryWorks – O4B10459 – 1967 vintage boiler, DHI= 500MMBtu/hr. EPA lists average Hg emission rate of 7.79E-7 lb/MMBtu, which is the average of the 3 identified emission test runs. However, during the emissions tests, the boiler was operating with 13% oil, 4% natural gas, and 83% blast furnace gas heat input. 12 fuel analyses were provided, all identified as No.4 Oil; all showed Hg at <0.05 ppm (equivalent to ~2.75 lb/MMBtu at detection level). A boiler predominantly fired on blast furnace gas and natural gas is not representative of a subcategory which is predominantly fuel oil fired.

D/F Top 12% Performers

1. SCMilliken-Dewey – D30 – 1965 vintage package firetube boiler with no APCD, DHI= 10.46MMBtu/hr. Fuel during boiler emissions test identified as Liquid Tetramer Byproduct from Anhydrides Process. EPA lists emission rate as 3E-6 ng/dscm TEQ. 12

fuel sample analyses were provided. Average HHV for the liquid for the 12 analyses was 25,064 Btu/lb. Cl for all analyses was <400 ppm DL. All three emissions tests were identified as BDL with the average emission rate given as 3E-6 ng/dscm TEQ, matching the value in the EPA MACT Floor table. Heat input during the test was 4.15MMBtu/hr. All congeners were listed as being below detection limit. This fuel is obviously unique and contains very low Cl, thus making it in no way representative of typical fuel oils used by the preponderance of liquid fired boilers and process heaters.

2. CTElectric Boat – EMU 17 – 1965 vintage firetube boiler with no APCD and no LNB, DHI= 7MMBtu/hr. EPA lists D/F emissions at 0.00109 ng/dscm TEQ. Heat input during test- 6.8MMBtu/hr. One fuel oil analysis identified as No.4 Fuel Oil was provided with Cl below detection level of 0.01%. Emissions test data indicates 5 congeners ADL; 4 BDL; 8 DLL.

3. NYConEd59thStStationNewYork – Boiler 118 – 1972 vintage watertube boiler, DHI= 180MMBtu/hr firing No.6 Oil identified as having no APCD. However, the D/F emission test spreadsheet indicates the boiler to be equipped with Fabric Filter Furnace Sorbent Injection (Dry) Low NOx Burners. EPA lists D/F emission rate as 0.0011 ng/dscm. All three runs were DLL, with various congeners indicating ADL/BDL. Heat input during the test was 166MMBtu/hr.

PM Top 12% Performers

1. TNMilanArmyAmmunitionPlant – D88L-1, Source #27-0010-86- 2002 vintage firetube boiler with no APCD and no LNB, DHI= 15MMBtu/hr, firing No.2 Oil. EPA gives average emission rate of 0.000511 lb/MMBtu, which is the average of the 3 reported runs. However one run was noted to be DLL.

2. SCGPChemRussellville – FO Boiler – 2008 vintage firetube boiler with no APCD, DHI= 32.7MMBtu/hr. EPA lists PM emission rate as 0.006 lb/MMBtu, which is the average of 3 runs. Fuel is identified as ultra low sulfur diesel fuel (</= 0.0015% S = 15 ppm). Heat input during testing averaged 19MMBtu/hr and flue gas O2 averaged 7.5%, which is very high for diesel fuel oil firing.

3. NJSunocoWestville – Boilers #5, #6, #7, #8- Boilers 5 through 8 are identical 250Mpph 2002 vintage package watertube boilers each identified in the EPA data as having an ESP, DHI= 350MMBtu/hr with refinery fuel gas and 330MMBtu/hr firing low sulfur jet fuel as backup fuel (Jet A). Per the emission test report, each boiler is equipped with Low NOx Burner, FGR, CO oxidation catalyst, SCR, and a wet ESP. Stack flue gas temperature is about 140F. EPA lists average PM emissions of 0.001819, 0.001022, 0.001718, and 0.000678 lb/MMBtu for Boilers 5, 6, 7, 8, respectively. These appear to be close to reported average filterable emissions, but it appears Boiler 8 was overfired during the tests based on the above rated heat inputs. Boiler 5 was tested on refinery fuel gas on 11/12-14/07 just prior to testing on Jet A fuel on 11/16/07, so there was very little firing time with Jet fuel prior to testing; this could impact particulate emissions due to liquid firing since there was very little time for accumulation of any particulate in the

boiler passes. In addition, it has been publicly reported that this particular refinery was shut down in late 2009, so these boilers are not now operational.

4. PAConemaughPowerPlantNewFlorence – Aux Boiler B – 2006 vintage package boiler, DHI= 213MMBtu/hr, No.2 Oil fired as backup fuel to natural gas. EPA lists filterable PM emissions at 0.000873 lb/MMBtu. Fuel oil analysis only gives HHV as 138,617 Btu/gal and 0.3%S. No emission test report is provided in the EPA support information. Emission test results for the 3 runs were 0.0013, 0.00032, 0.001 lb/MMBtu. Without the test report there is no way to identify if there were issues with the second run that led to significantly lower emissions than the other two runs. For comparison, the other auxiliary boiler at the site, a similar size unit, showed PM emissions of 0.009, 0.0087, 0.0047 lb/MMBtu for an average of 0.0075 lb/MMBtu, much more in line with Runs 1 and 3 for Boiler B. This raises a question about the validity of the second run for Boiler B.

5. WIGPGreenBay2818 – B10 – Wastepaper Sludge-Fired Boiler 10 – 1998 vintage watertube bubbling fluidized bed boiler equipped with SNCR and a fabric filter, DHI= 95MMBtu/hr. EPA ICR Answer Key information identifies fuel as deinking residuals. EPA lists emission rate as 0.001233 lb/MMBtu, which is the average of three runs conducted in 1999. Another PM test in 2007 indicated 0.0028 lb/MMBtu and another in 2009 indicated 0.00134 lb/MMBtu. Emission test spreadsheet identifies the fuel input as determined by weigh conveyor adjusted for moisture for average heat input of 74 MMBtu/hr; use of a weigh conveyor typically represents use of a fuel handled more as a solid than a liquid, which would typically be measured with some type of liquid flow meter. Indeed, GA Pacific indicates this unit is a solid fuel subcategory boiler, not liquid. Fuel analysis data for 2007-08 indicates an average deinking residual As-Received HHV of 2575 Btu/lb (4400 Btu/lb Dry), with moisture of 42%. Similar analyses for 2009 indicate a moisture content of 41% and a dry HHV of 3875 Btu/lb. So this fuel is a solid and not a liquid, and should not be part of the data used to determine the liquid PM MACT Floor.

6. PACherokeePharm – SG-C, Title V Source ID 037 and SG-B, Title V Source ID 036 – both are 1997 vintage watertube package boilers, DHI= 129MMBtu/hr, with no APCD. No.2 Oil is the backup fuel for natural gas. EPA lists emission rate as 0.0016 and 0.0018 lb/MMBtu for 037 and 036, respectively. These are the average of three runs conducted on each boiler in 1998. Fuel analysis only indicates 0.2%S. Both boilers have a 0.1 lb/MMBtu filterable permit limit when firing No.2 Oil. There is no emissions test report provided in the EPA support information.

7. SCMilliken-Dewey – D30 – 1965 vintage package firetube boiler with no APCD, DHI= 10.46MMBtu/hr. Fuel during boiler emissions test identified as Liquid Tetramer Byproduct from Anhydrides Process. EPA lists emission rate as 0.002167 lb/MMBtu, which is the average of three runs. This fuel is obviously unique and likely contains very low ash since it is a process byproduct, thus making it in no way representative of typical fuel oils used by the preponderance of liquid fired boilers and process heaters.

CO Top 12% Performers

1. SCDAKAmericas – P8F – 1978 vintage process heater (Dowtherm® A vaporizer-watertube design) with no APCD firing No.6 Oil, DHI= 38MMBtu/hr. EPA lists CO emission rate as 0.05147 ppm @3%O2 dry, which is the average of the reported M10 results for 6 runs (average of two 3 run averages). The emissions test report indicates that the CO analyzer was calibration checked with zero and 231 ppm CO cal gases before and after each run. Readings during every run varied both above and below zero during the tests. Per EPA Reference Method 10, the precision of the test method is +/- 2% of span and the accuracy is +/- 5% of span after calibration. For this testing using a span gas of 231 ppm CO, the accuracy of the test method during this testing was +/- 5% of 231 ppm, or +/- 11.55 ppm. Thus using an average CO emission rate of 0.051 ppm is wholly inappropriate and not indicative of actual emissions that might be measured with lower calibration span gas. Thus this data cannot be used at face value for establishing the MACT Floor.

2. ORGeorgiaPacificWaunaMill – EU33 – Power Boiler – 1965 vintage field erected natural gas/No.6 Oil fired 420Mpph boiler with no APCD, DHI= 192MMBtu/hr. EPA lists CO emission rate as 0.12509 ppm @3%O2 dry, which is the average of the reported M10 results for 3 runs. During the emission testing, the boiler was operated with 315.8 therms/hr natural gas (31.5MMBtu/hr) and an oil rate of 37.05 gpm (~333.45MMBtu/hr), resulting in 8.6% heat input from natural gas and the remainder from No.6 Oil. It is well known that natural gas cofiring with oil will enhance combustion efficiency due to the more volatile nature of natural gas, thus CO emissions test results while cofiring No.6 Oil with natural gas likely would result in lower emissions than when firing No.6 alone. Emissions were reported as being less than the detection limit of 0.1 ppm, though the analyzer was noted to have a calibration span of 100 ppm. That would be 0.01% of span, which appears to conflict with Reference Method 10 stated precision and accuracy limits. Raw CO data during almost all of the three runs was negative, thus raising additional questions of result validity to use in establishing a MACT Floor.

3. NJSunocoWestville – Boilers #5, #6, #7, #8 – Boilers 5 through 8 are identical 250Mpph 2002 vintage package watertube boilers each identified in the EPA data as having an ESP, DHI= 350MMBtu/hr with refinery fuel gas and 330MMBtu/hr firing low sulfur jet fuel as backup fuel (Jet A). Per the emission test report, each boiler is equipped with Low NOx Burner, FGR, CO oxidation catalyst, SCR, and a wet ESP. Stack flue gas temperature is about 140F. EPA lists average CO emissions of 0.2993, 0.8550, 0.1973, and 0.1282 ppm @3% O2 dry for Boilers 5, 6, 7, 8, respectively. These appear to be the reported average emissions. CO M10 span calibration was noted to be 12.4 ppm. It has been publicly reported that this particular refinery was shut down in late 2009, so these boilers are not now operational.

4. NENebraskaCityStation – Auxiliary Boiler 2 – 2006 vintage No.2 Oil fired package boiler with LNB only, DHI= 143MMBtu/hr. EPA lists average CO emissions of 0.2733 ppm @3% O2 dry, which is the average of the 3 reported runs. Fuel analyses for 2007-08 averaged 0.02%S. Per the emissions test report, it appears the NDIR analyzer was set up with a 1000 ppm span, with upscale calibrations between runs using 229 ppm CO cal

gas. Therefore, at best M10 precision specification of +/- 2% of span would allow for an accuracy of +/- 4.6 ppm CO. Thus data from this test indicating 0.27 ppm is well below the potential detection limitations of the methods used.

5. SCGPChemRussellville – FO Boiler – 2008 vintage ultra low sulfur diesel fuel oil fired package firetube boiler with LNB only, and no other APCD, DHI= 32.7MMBtu/hr. EPA lists average CO emissions of 0.37318 ppm @3% O2 dry, which is the average of the 3 reported runs. Upscale calibration span used 10.1 ppm CO cal gas. Fuel oil analysis did not include sulfur level, but probably 0.0015%S max.

6. NJMerckRahway – E750009 – Boiler #9 – 1997 vintage package watertube boiler with LNB and SCR, DHI= 99MMBtu/hr. No.2 Oil is a backup fuel to natural gas. The boiler is also capable of firing solvent with natural gas. EPA lists average CO emissions of 0.51473 ppm @3% O2 dry, which is the average of the 3 reported runs. CO analyzer calibration span was 25.8 ppm and test results indicated emissions less than 0.5 ppm (DL). The permit limit is 50 ppm CO @7% O2 dry when firing No.2 Oil.

7. OHOSUColumbus – B140 – 2004 vintage diesel fuel fired package watertube boiler with LNB and no other APCD, DHI= 206MMBtu/hr. EPA lists average CO emissions of 0.54434 ppm @3% O2 dry, which is the average of the 3 reported runs, however 2 of those reported at < 0.5 ppm (DL). The M10 analyzer was used with a 100 ppm calibration span. The reported results appear lower than the M10 accuracy specification warrants for use in establishing a MACT Floor. Fuel analysis indicated 0.03%S.

8. NCCampLejeuneMCB – C-CG-650-83B and 84B – 1969 vintage natural gas and Distillate Oil fired package watertube boilers with no APCD, DHI= 50MMBtu/hr. EPA lists average CO emissions of 0.8667 and 0.5667 ppm @3% O2 dry for 83B and 84B, respectively, which are the average of the 3 reported runs for each boiler firing No.2 Oil. The M10 analyzer was used with a 246 ppm calibration span. The reported results appear lower than the M10 accuracy specification warrants for use in establishing a MACT Floor.

9. VADominionPossumPoint – Aux. Boiler 001 – 2003 vintage package watertube boiler with no APCD, DHI= 99MMBtu/hr. EPA lists average CO emissions of 0.6286 ppm @3% O2 dry, which is the average of the 3 reported runs. However, the emission test report indicates that the boiler fired natural gas during the emissions testing, therefore, this unit is not appropriate to include for setting a liquid fired unit MACT Floor.

10. PAKeystonePowerPlantShelocta – Aux Boiler A – 1967 vintage No.2 Oil fired package watertube boiler with no APCD, DHI= 138MMBtu/hr. EPA lists average CO emissions of 0.7590 ppm @3% O2 dry, which is the average of the 2 reported runs. Fuel analysis indicates 0.27%S. The M10 analyzer was used with a 149 ppm upscale calibration span gas. The reported results appear lower than the M10 accuracy specification warrants for use in establishing a MACT Floor.

Therefore, if EPA were to promulgate MACT Floor emission limits for liquid fired units, it is obvious that major revisions would be needed to the approach taken and the floors determined.

It is also apparent that many floors are using very low sulfur oils/diesel/jet fuel compared to heavier oils.

D. EPA should extend the work practice approach used for Gas 1 to include Distillate Oil fired units.

As previously noted in lieu of emission limits, EPA has proposed work practice standards for certain existing units. The proposed work practice standard would include the implementation of a "tune-up" program. 75 FR 32012. While CIBO supports work practice standards, EPA should extend the work practice standard to cover distillate oil-fired units (including No.1, 2, ultra low sulfur distillate and diesel fuel, jet fuel, and other similar oils). EPA has treated distillate oil very much like it treats gas in the Proposed Rule and it should take the same approach when it comes to a work practice standard versus emission standards.

EPA established the MACT floors for liquid-fired units based on fuels that have low sulfur, chloride, and mercury content. As a result, the MACT floors were based on fuel characteristics and not on consideration of emission controls employed by the units. Considering this, EPA should not impose controls on boilers that burn a clean liquid fuel such as distillate fuel that do not contain the low chloride and mercury contents of the fuels used to establish the MACT floors. This is unreasonable, as units that burn distillate fuels have no control over the quality of the oil they receive, and will have additional costs to control very low levels of Cl and Hg to the HCl and mercury limits. In many cases it is problematic to try to design and obtain emissions controls for such low contaminant levels, since the levels in the oils are below detection levels already.

If EPA determines that work practice standards are not appropriate for distillate oil, emission limits should be changed and based on fuel oil quality or composition. This would be an acceptable approach considering distillate oil is commercial grade heating oil. EPA has no justification to impose upon ICI users of commercial fuel oil the emissions reductions that are not imposed on other uses of the same fuel oil. If EPA determines that restrictions are justified, those restrictions should be placed on the suppliers of the distillate oil to meet any limitations in quality without back-end cleanup equipment.

XV. Table 1 and 2 Emissions Limits

A. Combination Fuels.

Under the Proposed Rule, boiler units that burn more than 10 percent coal with biomass will be classified in the coal subcategory. 75 FR 32065. The 10 percent threshold established by EPA is arbitrary and EPA has failed to justify it as an appropriate threshold for defining a primary fuel. EPA then included emission data from such boilers along with 100 percent coal-fired boilers to establish standards for new and existing sources. This is inherently unfair to both biomass and coal fired boilers. Coal-fired boilers will inherently have higher emissions of HCl and mercury whereas biomass boilers will inherently have higher CO emissions.

This threshold is especially problematic for units that burn biomass with coal. If these predominantly biomass burning units exceed the arbitrary 10 percent threshold, they will be required to comply with the coal subcategory emission standard for CO. Such units are unable to meet the CO emission standard for coal. CIBO recommends that EPA amend the Proposed Rule to include an additional subcategory for combination boilers that burn both coal and biomass. EPA should reverse its methodology and only use data from boilers burning at least 90 percent coal to set standards for the coal subcategories and to use data from boilers burning less than 10 percent coal to set standards for the biomass subcategories. For combination boilers, EPA should allow compliance to be determined using weighted averages such as in NSPS Db where EPA used this methodology for sulfur dioxide and NOx. We do not see any issues related to enforceability of such weighted average standards that cannot be overcome with today's information technology. Another option is for EPA to apply the CO and dioxins/furans emission limits for the biomass subcategory to units in this new subcategory.

Such an approach is justified for a variety of reasons. First, if units that co-fire biomass and coal cannot comply with the CO standard it is likely they will switch away from biomass and burn more coal to be able to comply with the coal subcategory emission standards. Discouraging the use renewable biomass fuel is contrary to current U.S. energy policy.

B. Achievability.

In enacting subsection 112(d), Congress established a statutory scheme whereby EPA is supposed to determine what the best performers do to achieve the "maximum degree of reduction in emissions." See CAA § 112(d)(2) and (d)(3). The floor limit, however, cannot be "less stringent than the emission control that is achieved in practice by the best controlled similar source." CAA § 112(d)(3). This requirement incorporates a concept of "reproducibility" by others in the source category or subcategory.

The concept of reproducibility emanates from two places. First, the legislative scheme incorporates it. The whole idea behind the floor setting procedure is to discover what techniques the "best performers" use to achieve low emissions so that the other, higher emitting sources in the category or subcategory can replicate those actions and achieve those same low levels. As EPA noted in the Cement Kiln case, the intent of the standard setting process is to discover the "objective, duplicable control" techniques so that other performers in the source category could emulate those techniques, reduce their emissions, and achieve those levels. See EPA Response Brief, Cement Kiln, at. n. 57.

Second, reproducibility is included in the statute's floor setting provisions. Section 112(d)(3) states that that the floor standards reflect what the "best controlled similar source" does. This reflects the Congressional directive that the best performers must actually be controlling their emissions and their technique must be capable of being reproduced by others in the source category. Thus, the Agency's floor determination must discover the techniques that the best performers are using to actually "control" emissions, i.e., exercising some degree of management that is duplicable by others. The Agency's analysis, therefore, must determine what is the maximum degree of reduction that the best similar source achieves through methods of control.

The emission standards set forth in Table 1 and Table 2 are unworkable. What is achieved in practice does not equate to achievability. As noted elsewhere in these comments, in evaluating the emission limits achieved by existing sources, EPA is required to estimate the variability associated with all factors that impact a source's emissions. EPA must also allow "a reasonable inference as to the performance of the top 12 percent of units," and show "*why* its methodology yields the required estimate." *Cement Kiln* 255 F.3d at 862. While EPA is correct to incorporate variability analysis into the MACT floor analysis in this rulemaking, the result does not appear to reflect the full range of variables potentially impacting emissions.

In fact, EPA's proposed pollutant by pollutant approach for establishing emission limits for new sources is unreasonable, primarily because the limits were based on levels of *individual pollutants* achieved by the best performing source in the category. Essentially, the standards for new sources are established based on a hypothetical boiler able to meet the emission limits for all pollutants. None of the top performers EPA relied on in setting the emission limit for a given pollutant are capable of meeting the emission limit for all pollutants. EPA's method has produced an unfair and unworkable result.

C. Limits Should be Corrected.

The Proposed Rule includes CO emission limits for solid fuel burning units "corrected to 3 percent oxygen." 75 FR 32066-67. In the final rule, EPA should amend the CO limits so that they are corrected to 7 percent oxygen, just as the dioxin/furan limits are. This is appropriate as 7 percent oxygen is generally a more common operating level for units burning solid fuels. Furthermore, the Proposed Area Source Rule includes CO emission limits corrected to 7 percent oxygen. 75 FR 31932.

Additionally, the dioxin/furan emission limits for liquid and Gas 2 is currently corrected to 7 percent oxygen. 75 FR 32067. The dioxin/furan emission limit for liquid and Gas 2 should be corrected to 3 percent oxygen, just as oxygen is listed for CO for those fuels. This is appropriate as 3 percent oxygen is generally a more common operating level for liquid and gaseous fuels. Furthermore, the Proposed Area Source Rule includes dioxin/furan emission limits corrected to 3 percent oxygen. 75 FR 31932. Overall, CIBO recommends that EPA establish all emission corrections for a particular fuel corrected to the same oxygen level.

D. Opacity limit of 10% on a daily block average will not be adequate to allow operation during SSM periods.

As recommended elsewhere in these comments, CIBO recommends that startup and shutdown periods be handled using a work practice standard. Limiting opacity to 10% on a daily block average may be appropriate for normal operation, but it will not allow startup and shutdown operations to proceed, since there is simply not enough time to average out to such a low limit. Use of startup and shutdown work practice with a prescribed plan is an appropriate approach that can be tailored to the specific unit. A similar approach needs to be provided for malfunctions so that actions can proceed in an orderly and safe manner to address malfunctions.

XVI. CO Control Costs

EPA estimates 482 units will install CO catalysts to control CO emissions. It would be very difficult to retrofit CO catalysts to existing boilers and process heaters. It is also not assured that such installation could actually achieve the emissions limits proposed. CIBO recommends that EPA re-evaluate the approach taken and the data used to account for actual achievability and costs. CIBO believes the actual retrofit cost for CO catalysts will be very high.

Due to the lack of widespread deployment of CO catalysts on industrial solid-fueled boilers, many boiler owners are likely to view this technology as inherently more risky than traditional in-furnace techniques to control CO. The most commonly employed and cost effective method reducing in-furnace CO formation would be to "de-tune" the furnace by removing low-NOx firing systems and installing 1960's vintage burner systems that produce very low CO. Many companies will view this as posing significantly less technological risk than CO catalysts, due to their widespread use in boilers. As has been long established in the industry, a generally inverse relationship exists between CO and NOx in a well-tuned boiler. However, many industrial boilers are already either obligated to meet a specific NOx emissions standard, or to optimize NOx to achieve compliance with NAAQS Ozone standards, or both. Therefore the net effect of this CO standard will be to drive companies to "de-tune" their furnaces to control CO, and retrofit capital intensive NOx reduction technologies (e.g. Selective Catalytic Reduction) to control the resultant increase in NOx. EPA's own literature (EPA/600/SR-01/087 January 2002) provides a capital cost estimate of $50-110 per kW. Because these cost impacts have not been factored into EPA's estimates of the costs for controlling CO, EPA's estimates are significantly low. EPA should revise its estimates of the cost to industry to reflect one of the least technologically risky, and therefore one of the most probable, responses of many companies to comply with this standard.

XVII. Alternative Approach

EPA discusses an alternative approach and floor limits if solid waste includes expanded materials, such as secondary wood products combusted on site; coal refuse; tires processed into TDF; on spec used oil; and all secondary materials used as ingredients managed outside the control of the generator in combustion units.

EPA's Alternative Approach for determining materials to be fuels and not solid waste will further discourage alternative energy sources and EPA should not finalize those provisions. The alternative approach in the Proposed Rule (75 FR 32035) would likely greatly inhibit the use of valuable, energy-rich materials as fuels by boilers. For that reason alone, CIBO opposes adoption of an even more restrictive approach than the basic approach outlined in the proposal. Implementing this alternative approach would only amplify the wasted resources and the false benefits of subjecting boilers burning secondary material fuels to the incinerator rule requirements. Under the alternative approach, traditional fuels that have been burned historically as fuels and managed as valuable products would not be solid wastes. In addition, nonhazardous secondary materials used as fuels or ingredients are excluded from the definition of solid waste if they both remain within the control of the generator and meet the legitimacy criteria. Of concern to CIBO is that all other nonhazardous secondary materials burned as a fuel or used as an ingredient in the combustion process would be classified as solid wastes subject to the CAA § 129 standards if burned in a combustion unit. Also, all materials that result from processing of discarded nonhazardous secondary materials would be classified as solid wastes. As with the proposed approach, wastes would include those secondary materials used as a fuel or ingredient not passing the legitimacy criteria, and those secondary materials used as a fuel that are managed outside the control of the generator. This solid waste designation would include materials, such as secondary wood products combusted on-site, coal refuse, and tires processed into TDF, on-spec used oil, and all secondary materials used as ingredients managed outside the control of the generator in combustion units. There would be no opportunity to demonstrate otherwise through a petition process. Based on these negative impacts and features, CIBO opposes the alternative approach.

XVIII. Operating Limits

A. Operating Limits Approach Is Unworkable.

EPA proposes that operating parameters measured during performance tests should constitute minimum site-specific operating requirements subsequent to the performance test. It is inappropriate and in many cases not technically feasible to use near-ideal operating conditions during a performance test, which are typically conducted at or near the unit's maximum firing rate, to establish a minimum requirement for all possible load ranges. EPA should amend the Proposed Rule to allow for optimum system operations and ratio-type parameters. The following comments detail why the current proposal is unacceptable.

EPA sets minimum required operating parameters at high load conditions, which are applicable to all operating conditions going forward. This approach is unacceptable. EPA's function is not to dictate how a source operates each and every unit, but instead to limit emissions impacts to the environment. It is unreasonable to place many of the hard limits derived from the operating limits approach on a facility long term. EPA provides in the Proposed Rule that boilers and process heaters without wet or dry scrubbers that must comply with an HCl emission limit must "measure the average chlorine content level in the input fuel(s) during the HCl performance test." 75 FR 32013. Such an operating limit would be unmanageable long term as it would require exact replication of the test fuel, which in some cases is not likely and would also eliminate the use of permitted opportunity fuels. EPA has does not have the expertise, nor the legal authority to mandate such an approach.

With many pollution control technologies, the proposed approach to establishing and maintaining minimum operating limits would result in needless over-consumption of sorbents at great cost to the facility with little or no commensurate benefit to human health. As an example, the sorbent injection rate of activated carbon for the control of mercury varies with the volume of flue gas generated during combustion. To establish a minimum sorbent injection rate at or near the unit's maximum continuous rating (MCR) would result in nearly double the sorbent injection rate during turndown to 50% load. While such an approach may work for based loaded utility boilers that are baseloaded, there are a great diversity of units and operating conditions affected under this rule as compared to utility-type units. Institutional, commercial and industrial boilers vary loads widely based on site conditions, business conditions, season and time of day, and other factors. This minimum sorbent flow requirement would result in pointless expense to the facility with no benefit to the environment or to human health.

Other pollution control technologies cannot practically maintain operating conditions established at or near full load during turndown conditions. For example, a Spray Dryer Absorber (SDA) slurry injection rate is limited by the ability of the flue gas to evaporate the liquid portion of the slurry. At or near full load, with high flue gas flowrates and high flue gas temperatures, the flowrate of slurry will be relatively high. If this were established as a site-specific minimum sorbent injection rate, the unit would inject more slurry than the flue gas could accommodate at low loads. One member company with solid-fuel fired boilers equipped with SDA's experienced catastrophic failures due to operation where more slurry was injected than the flue gas could evaporate. Operating limits are simply unacceptable for throughput and firing load variations and to attempt to include them would require excessive and unnecessary costs for minimal, if any, environmental benefit.

1. Variability of Sorbent Injection Over Loads.

Sorbent injection limits should not be fixed at the as tested/full-load injection rates as in many cases this is not considered normal boiler operation. This results in a waste of sorbents resulting in excessive O&M costs to the boiler owner in many operating load ranges, and can compromise the integrity or reliable operation of some types of pollution control equipment. An option to include a feed forward and possibly feed back control logics should be allowed that sets injection rates based upon a feed forward operation signal such as gas flow rates or a feed back signal from certified CEMS if provided. i.e. Feed rates for mercury control are calculated based upon lb/MMacf.

2. Values Obtained During Initial Performance Tests are Not Necessarily Representative.

CIBO also has concerns with the representativeness of values measured during a source's initial performance test. EPA asserts performance tests must be conducted using "worst case fuels" with respect to emissions of PM, metals, HCI, and mercury, i.e. the fuel mix that results in the highest emission levels for these substances. The practicality of requiring worst-case fuels for performance testing purposes is addressed separately in these comments. However, burning "worst case" fuels may not result in the "worst case" emissions. Such a requirement imposes an arbitrary lowering of emission limits under other operating and fuel conditions.

CIBO supports use of fuel analyses and fuel supplier certification with extrapolation allowed from performance test levels to the emission limits as a more appropriate approach for assuring compliance with the total metals and mercury limits (and HCl emission limit as explained elsewhere in these comments). Initial performance testing, periodic emissions testing, and use of operating parameters are adequate to provide assurance of compliance.

B. The Current Approach Should Be Changed.

The current operating limits approach should be changed to allow for optimum system operations and ratio parameters. The Hazardous organic NESHAP (HON) allows for single-point testing and extrapolation with engineering judgment. 59 FR 19425 (Apr. 22, 1994). Other MACT standards simply recognize that it is not always possible to establish these operating ranges solely on performance test data. For example, the HON found at 40 CFR 63 Subpart G has the following relevant provision:

> If a performance test is required by this subpart for a control device, the range shall be based on the parameter values during the performance test and may be supplemented by engineering assessments and/or manufacturer's recommendations. Performance testing is not required to be conducted over the entire range of permitted parameter values.

40 CFR 63.152(b)(2)(ii)(A). This type of provision allows each source to use the performance test data to then extrapolate operating limits based on equipment specific considerations. This is done in an operating plan that is submitted to the air permitting authority for review. A similar provision is needed in the final rule to accommodate situations such as those we have described above. The method contained in the HON is what should be adopted as it allows the source to propose the single-point testing based on what is appropriate and allowed in the rule without alternative monitoring procedures. If EPA decides upon this approach it should modify certain definitions including the following: minimum pressure drop; minimum scrubber effluent pH; minimum scrubber flow rate; minimum sorbent injection rate; minimum voltage or amperage.

C. Continuous Compliance Proposal of 12-hour block averages.

EPA has proposed operating parameters of 12-hour block average based on 4-hour averages. 75 FR 32033 CIBO recommends that EPA adopt instead a 24-hour rolling average for operating parameters. This will allow for normal operating fluctuations and slower emissions response to operating parameter changes and startup/shutdown periods. The HON uses 24-hour block average for chemical processes that typically do not vary greatly due to throughput or firing rate. This generally occurs for boilers where the additional latitude of a rolling average is more appropriate. If EPA does not determine the 24-hour rolling average is appropriate, CIBO proposes a 24-hour block average, and alternatively, a 12-hour rolling average. Furthermore, the Proposed Rule is inconsistent in the averaging times specified for operating parameters. EPA should amend § 63.7525(d)(4), which currently references 3-hour block averages, so that it reflects what is stated in Table 8 75 FR 32056, 32072.

D. Continuous Parameter Monitoring System Maintenance Procedures.

EPA has proposed that the continuous parameter monitoring system (CPMS) complete a minimum of "one cycle of operation for each successive 15-minute period" and have a minimum of "four successive cycles of operation" for a valid hour of data. 75 FR 32056. This requirement could result in certain units that do not currently have CEMS installed being forced out of CAM. EPA should amend these provisions and provide a methodology to explain how it is to be implemented to avoid automatic deviations upon a problem with operating data. EPA must provide flexibility to control sorbent feed rates based on CEMS output over full load range and fuel qualities in cases where CEMS are utilized.

XIX. PM CEMS

A. PM floor Based on Three, One-hour Emission Test Runs.

EPA should also use data from existing PM CEMS to determine variability impacts for inclusion in establishing the floor when PM CEMS are required. If PM CEMS are required for specific units, EPA needs to include consideration of actual PM CEMS response for units in the particular subcategory firing applicable fuels. It is inappropriate to only use 3 limited time reference method runs to establish an emission limit that will need to be met using continuous monitoring. Reference method testing at high load steady state conditions does not represent actual average emissions as would be measured over all operating conditions with a CEMS.

B. EPA's Proposed PM Limit for Units > 250MMBtu/hr and Requirement to Use PM CEMs Is Too Stringent.

EPA proposes that particulate matter CEMS be installed on units > 250MMBtu per hour to satisfy continuous compliance requirements for particulate matter emissions. 75 FR 32055. The installation and annual certification expenses for the PM CEMS are extreme and unreasonable. As an alternative to PM CEMS, CIBO recommends that EPA allow the installation and operation of bag leak detection systems in accordance with the Proposed Rule's §63.7525(j)(1) through (8) in addition to the existing opacity monitors. The bag leak detection system provides ongoing monitoring of the bag house component performance and provides for continuous compliance demonstration.

EPA's proposed liquid PM limit is too stringent. The majority of residual oil ("RO") units will have to install PM controls or convert to gas if it is even available. It is likely that the liquid PM limit is too stringent to meet without controls in RO units. Control options for a large RO unit will typically be a cyclone/scrubber, ESP, or bag-house (but bag blinding will be a likely problem). Each of these control options will effectively control PM down to low levels; however, it still may not be enough to consistently comply with the very low proposed PM limit for liquids because as indicated above, it is in part based on units combusting liquids that are not representative of fuel oils. According to the proposal, the RO units will have to install various control device monitoring devices, including installation of PM CEMS on units greater than 250 MMBtu/hr. In summary, EPA should consider the following with regard to the proposed PM CEMS requirement:

1) Large RO units, and probably large solid fuel units, should not be forced to install a redundant PM monitoring system (i.e., PM CEMS) in light of the fact that the resultant emissions after installing equipment to comply with Boiler MACT are likely to be low.

2) EPA should provide an achievable alternative to install PM controls on existing RO units rather than encourage the conversion to gas. Requiring excessive and redundant PM monitoring systems on large RO units is just another reason to convert to gas.

3) Based on best performer PM data for liquid fired units noted above, it appears lowest emission rate units fire lower sulfur oil. It is logical that PM emissions are associated with the sulfur level since the EPA document AP-42 Table 1.3-1 equation for filterable PM is calculated from oil sulfur level. EPA should evaluate all available data and evaluate PM emissions as a function of Residual Oil sulfur content and provide an alternative standard that simply requires use of low sulfur Residual Oil. Such a standard could rely on supplier certification of the oil sulfur level. This low sulfur option approach is believed also adequate for fuel dependent HAP emissions such as HCl and Hg as well. EPA can evaluate and support that approach with the available data.

4) It appears that EPA has never required a PM CEMS without allowing for alternative PM monitoring options. At the very least, EPA should explicitly open

the door to alternative site/unit specific PM monitoring proposals in the rule for large RO fired units.

EPA's requirement that PM CEMS should be used to demonstrate continuous compliance on all solid fuel boilers larger than 250 MMBtu/hr is arbitrary and not supported by any data. There is no published information documenting that PM CEMS installed on multi-fuel boilers can measure PM emissions accurately and demonstrate compliance with PS 11.

In the preamble to the Proposed Rule at 75 FR 32033, EPA asked for comments on its determination that PM CEMS should be required and used for determining compliance with the emission standards on boilers which burn coal, biomass, or oil and have a heat input capacity greater than or equal to 250 MMBtu/hr. The installed PM CEMS would be required to meet Performance Specification 11 and also comply with Procedure 2 in Appendix F to 40 CFR 60.

In order for a CEM to be suitable for demonstrating compliance, a CEM must be accurate and precise under all operating conditions, and must have demonstrated the capability of sustained operations for long periods of time. However, as discussed below, these needs are not met when considering installation of PM CEMS on solid fuel boilers.

EPA has failed to provide any technical information regarding the suitability of PM CEMS as compliance monitors. Instead, in the proposal EPA has 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 information does not establish the performance capabilities of PM CEMS and does not justify their use as compliance monitors for all industrial boilers over 250 MMBtu/hr.

An examination of the history of PS 11 and Procedure 2 shows that EPA promulgated PS 11 and Procedure 2 based on very limited data. When EPA initially proposed PS 11, it was based on EPA's view of what the capabilities of PM CEMS should be. However, the very few PM CEMS installed on electric utility industry boilers could not meet the proposed requirements. Consequently, PS 11 was extensively modified based upon utility industry data. At the time of the promulgation of PS 11, no information was provided by EPA regarding the capability of PM CEMS to satisfy PS 11 on sources other than coal-fired electric utility boilers nor was an opportunity provided to the industry to comment on the suitability of implementing PS 11 and Procedure 2 on specific source types.

There are several significant issues with installing PM CEMS on multi-fuel boilers and biomass boilers commonly used in the forest products industry that need to be addressed before installation of such systems:

Among the instruments used to quantify PM emissions are light scattering, optical scintillation, electrostatic induction, and beta gauge instruments. The responses of these instruments are expected to be affected by the size and nature of particles being emitted. Thus the calibration curve for such instruments would be expected to change as the fuel mix changes. Multi-fuel boilers, such as those used at pulp and paper mills co-fire a wide variety of fuels, including coal, wood (bark), tire-derived fuel, pulping process residuals, waste treatment residuals, oil and natural gas. Each of these fuels may be fired at different levels during an operating day depending upon process conditions and availability. EPA has not published the results of any study examining these issues and thus is not in a position to confirm that given the changing nature of PM emissions from multi-fuel boilers, PM CEMS will accurately measure source PM emissions.

Similarly, even "biomass boilers" may burn different types of biomass. For example, boilers at plywood plants burn bark removed from the logs before they are processed into veneer and also burn trim and scrap from the finished veneer. Again, EPA has not published the results of any study examining biomass boilers and thus is not in a position to confirm that given the changing nature of PM emissions from these units, PM CEMS will accurately measure source PM emissions.

Although EPA has mentioned installation at utility industry boilers, it has not provided reference to any peer-reviewed publication documenting that PM CEMS are routinely capable of meeting the requirements of PS 11 and PS2 and measure PM emissions accurately.

PS 11 specifies in Section 8.6 (4) (i) that simultaneous CM 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 or malfunctions, the facility would have to conduct the correlation tests at emission levels that exceed the emission standards.

C. Does EPA have the legal authority to require a source to operate above its permit limit?

EPA assumes that PM emissions from a source can be controlled within a narrow range through minor operating changes. Such changes in PM emissions are not always easily accomplished. For example, the efficiency of a wet scrubber is affected by the particle size distribution, gas flow rate, pressure drop, and scrubbing solution flow rate. Thus a facility cannot just dial a PM emission rate and continue their PS 11 test. Similarly, it is not clear how a facility equipped with a bag house will achieve targeted PM emission rates to satisfy the requirements of PS 11, other than purposefully creating a hole in one or more of its bags (certainly not a desirable action).

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 a correlation coefficient of ≥0.85 between measured and predicted stack gas PM concentrations. A confidence interval (95%) mid range value at the mean PM CEMS response of ±10% of the emission limit, and a tolerance interval mid range 95% confidence interval value such that 75% of all possible values are within 25% of the PM emission limit. This suggests a very high probability that many CEMS PM measurements that show up as exceeding the standard would actually be below the emission standard. In this situation, operators would be forced to make changes to a control device or even shut down the boiler if these changes did not cause a response, even though PM emissions were in compliance with the standard. This is in direct conflict with the current view of compliance. If it is EPA's desire to use PM CEMS for demonstrating compliance, it must show how compliance would be determined with devices with such a high error band.

In proposed § 63.7525(b)(6) it is specified that when PM CEMS data are "not obtained because of CEMS breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 of appendix A of 40 CFR part 60 to provide, as necessary, valid emissions data for all operating hours per 30-day rolling average." 75 FR 32055 This is very different from the CISWI rule which has specified valid data capture requirements in Section 60.2730 (n) (14). Even more confusing and conflicting, Proposed Section 63.7535(b) says "Except for monitor malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), you must monitor continuously (or collect data at all required intervals) at all times the affected source is operating." 75 FR 32056. If the 100% data availability requirements for boilers is not changed, boilers with heat inputs >250 MMBtu would be forced to have duplicate PM CEMS systems so that emissions data are also available during calibration checks, and zero and span adjustments which are required daily. And, since two CEMS systems are required for normal operation, a redundant third CEMS will have to be installed for periods when one of the two systems malfunctions.

EPA should change the boiler MACT requirements language in 63.7525 (b)(6) to what is required in Section 60.2730 (n) (14) for CISWI sources.

To measure and report PM emissions in lb/MMBtu, boilers 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 multi-fuel boilers, biomass boilers, or CISWI sources, 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 and multi-fuel boilers and CISWI sources.

Absent the questions about the feasibility of installing PM CEMS on biomass and multiple fuel boilers, we believe that these monitors are not necessary, given the annual PM testing requirements and continuous parametric and opacity monitoring. If PM CEMS remain a rule requirement for larger boilers, the averaging period should be increased to 30 days, similar to the averaging period for sources installing CO CEMS. As stated in the discussion elsewhere in these comments regarding averaging times and SSM, it will be difficult for sources to meet 24-hour block average limits when operational variability and SSM are considered.

1. Requirements appear excessive and costly given marginal environmental benefit.

Proposed section 63.7540(a)(9) requires annual RATA testing, plus initial correlation testing, and then response correlation audits every 3 years. Response correlation audits include a minimum of 15 manual reference tests over the full range of PM responses that correspond to normal operating conditions for the source and control device and result in the widest range of emission concentration. This entails considerable cost and time for testing. EPA should justify why the every 3 year response correlation audits are required if fuel types and equipment do not change over that period compared to the apparent initial correlation testing and annual RATA in PS-11/Appendix F. This additional testing imposes additional cost with no additional environmental benefit over use of COMS/BLD and periodic PM testing. Since that is the case, it also appears that required use of PM CEMS has not been justified.

2. PM CEMS compliance basis.

a. Conflicting averaging times in the Proposed Rule

EPA states that PM CEMS would be used to demonstrate a monthly average is maintained below the applicable PM limit. 75 FR 32014. Section 63.7525(b)(3) indicates compliance on a 24 hour block average basis as an average of the hourly emissions and 63.7525(b)(4) indicates a 30 day rolling average basis. EPA needs to be consistent in the required compliance averaging time. CIBO recommends that a 30 day rolling average basis is most appropriate and allows for normal operational variations.

b. SSM periods should be handled as awork practice

Even with use of a 30 day rolling average for PM CEMS, that is not adequate to cover SSM periods, and the emissions data used to establish the emission limits does not include SSM periods. CIBO recommends that SS and M periods be handled with a work practice approach.

D. EPA should allow PM CEMS as an alternative to opacity or BLD approaches.

There may be some applications where use of PM CEMS makes sense. EPA should allow sources the option of using a PM CEMS or COMS/BLD with PM emissions testing.

E. Rule should specifically state that if PM CEMS is installed, neither COMS nor BLD should be required.

However, to be clear and prevent confusion, EPA needs to specifically state that when a PM CEMS is installed, neither a COMS nor BLD is required to be installed. That is not clear in the Proposed Rule. This approach is included in the Proposed CISWI Rule preamble. 75 FR 31961. EPA should include the following in the final rule: "PM CEMS. The proposed amendments would allow the use of PM CEMS as an alternative testing and monitoring method (except for energy recovery units with a heat input capacity greater than 250 MMBtu/hr which are required to use them). Owners or operators who are required to use, or choose to rely on, PM CEMS would be able to discontinue their annual PM compliance test. In addition, because units that demonstrate compliance with the PM emission limits with a PM CEMS would also be meeting the opacity standard, compliance demonstration with PM CEMS would be considered a substitute for opacity testing or opacity monitoring. Owners and operators who use PM CEMS also would be able to discontinue their monitoring of minimum wet scrubber pressure drop, horsepower or amperage."

XX. CO CEMS COST ESTIMATES

A. EPA Should Use Alternative Option For Using CO Limit As lb/MMBtu For Optimum Use of Existing CEMS Equipment.

EPA proposed Carbon Monoxide limits listed in parts per million (ppm) corrected to 3% Oxygen (O2). Some sources have existing CEMS that already monitor O2 as the diluent gas to demonstrate compliance with other emission standards, and would require upgrades or expansions to the CEMS to monitor CO for compliance with this rule. However, many sources covered under this rule already have existing Continuous Emissions Monitoring Systems (CEMS) that measure Carbon Dioxide (CO2), either as the diluent gas or to demonstrate compliance with other emissions standards. Sources which use CO2 diluent gas monitoring in lieu of O2 diluent gas monitoring typically utilize dilution-extraction sampling and conditioning systems, where compressed air is used to dilute the flue gas sample prior to being analyzed in a pollutant monitor. Dilution-extraction systems cannot monitor flue gas O2 due to the introduction of fresh air at high ratios, often of 50:1 or 100:1. Because sources with dilution-extraction sampling systems would be unable to adapt or expand their existing CEMS to monitor O2, those sources would be required to install a completely separate and independent CEMS system. A requirement to install such a redundant CEMS, when an existing CEMS is already present and functional, is an unreasonable cost burden to be imposed on sources. One member company projects additional costs in excess of $100,000 per boiler due to the infeasibility of utilizing existing dilution-extraction CEMS to measure O2 on multiple boilers at a single plant site.

EPA should allow sources to comply with an alternative standard for CO, where the emission standard is expressed in pounds per million BTU of heat input (lb/MMBtu). This would be consistent with most other emission standards in this rule, and with many other emissions monitoring requirements outside this rule (e.g., NSPS). This alternative standard would require only moderate, reasonable modifications to dilution-extraction CEMS that monitor CO2 instead of O2 as the diluent gas. EPA could devise a CO lb/MMBtu standard that would provide the same degree of protection of human health and the environment as the currently proposed CO ppm standard without imposing unnecessary cost burdens on sources.

B. EPA needs to clarify CO CEMS applicability.

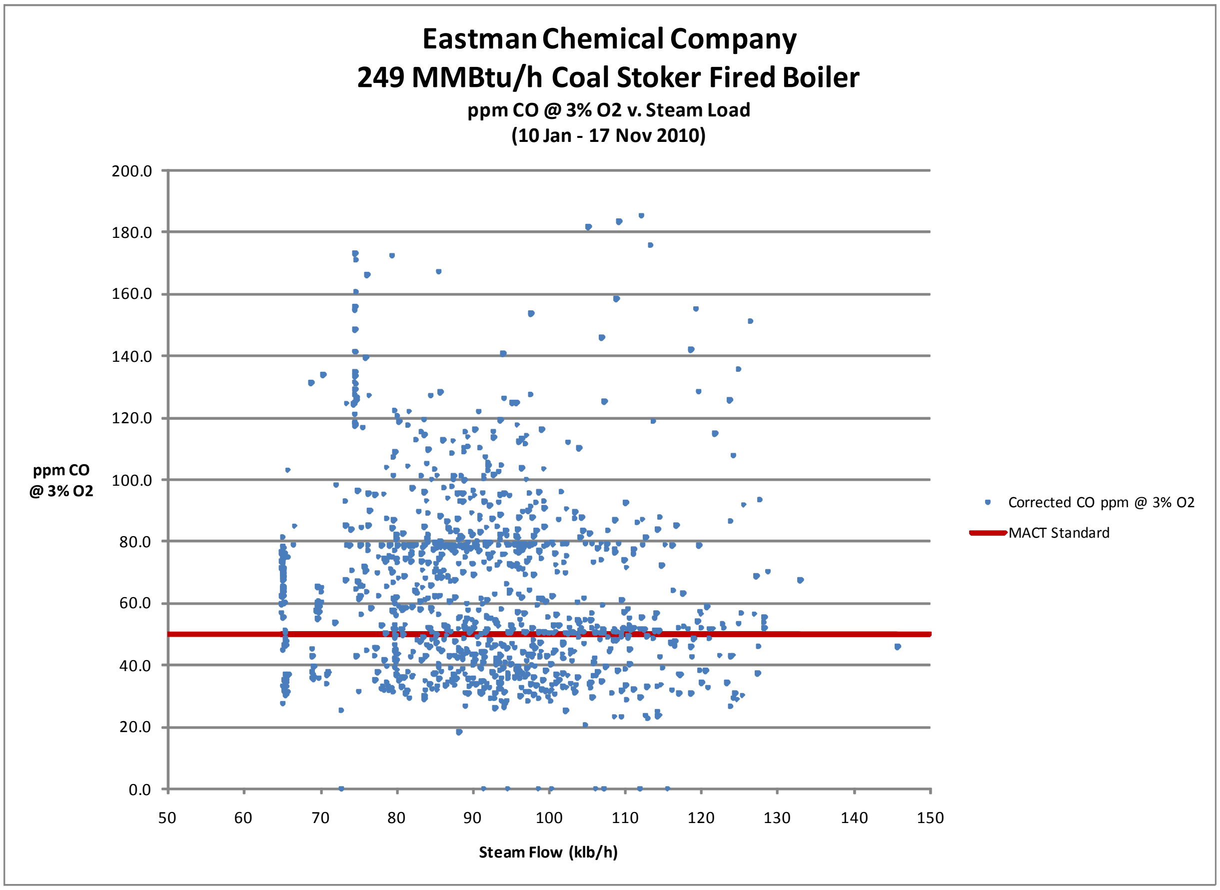
EPA needs to clarify in the rule the specific units for which CO CEMS are required. It needs to be clear that they are only required for specific sources that have CO emission limits stipulated in Table 1 or Table 2.

C. Availability of CO CEMS.

It appears that over 1000 CO CEMS might be required under this rule. This is a very high number that will be required over a short time period. EPA has provided no information or assurance that that number of units can be provided by suppliers. EPA should investigate this issue and allow for an extended compliance date if availability of CO CEMS is a problem.

D. EPA's Statement That CO Emissions Do Not Vary "Significantly" Over the Operating Range is Incorrect and Unsupported By the Operating Data.

EPA contends that emissions of carbon monoxide (CO) do not vary significantly over the operating range of the unit. This belief is used to explain why additional operational variability was not added to account for operation at lower capacity rates. This contention is incorrect and not supported by CO data from existing industrial boilers. See the figure below showing 10 months of CO data plotted against steam generation from January through November 2009 from one of Eastman's coal stoker-fired boilers.



CO Emissions versus Steam Load from Eastman 249 MMBtu/h Coal Stoker Fired Boiler

This data shows that across an operating range of 41% - 91% of the unit's Maximum Continuous Rating (MCR), emissions of CO ranged from -37% to +708 % of the average CO emissions. This data clearly demonstrates that significant variability can and does exist across a unit's load range. The degree of variability is highly dependent upon the specific unit: Furnace design, fuels fired, mode of operation (steady state, ramp rates, etc.), and a variety of other factors.

Besides this data submitted for the Eastman boiler, EPA's own data for the Phillip Morris PC boiler also shows a relationship of CO to load. EPA's graph of the CO CEMS data plotted vs boiler load for the Phillip Morris boiler in Virginia (the only pulverized coal boiler with CEMS data in EPA's dataset) (see Appendix B-1 of the MACT floor memorandum) is wrong (it appears to plot the Excel row number vs. CO) and does not include data from boiler load below 100 MMBtu/hr.

EPA should revise the variability factors used in establishing floor values for CO by collecting additional CO CEMS data from top performers. EPA should use this data to determine realistic variability factors that account for the highly variable nature of CO emission from real-world boilers, and use that data to set more realistic floor values.

E. The CO CEMS requirement for units Less Than 100 MMBtu is unreasonable.

The requirement for CO CEMS for units > 100 MMBtu per hour is too onerous. Many units at this size in the industrial and institutional sector do not operate that frequently, therefore the cost of installing CO CEMS is not justified for units with such limited operation. CIBO recommends that EPA remove this requirement and present alternatives to either install CEMS or use stack testing for any units with limits. EPA could also increase the threshold requirement for CO CEMS to 250 MMBtu per hour or provide a limited use exemption such as 10 percent use.

XXI. Emissions Testing

A. EPA's Proposed Performance Testing Requirements Are Excessive and Should Be Reduced to a Reasonable and Appropriate Level.

EPA's proposed performance testing requirements are excessive and should be reduced to a reasonable and appropriate level. EPA proposes that all units subject to numerical emission standards conduct performance tests annually for all five pollutants: particulate matter (not required for units over 250 MMBtu/hr with PM CEMS, but those do need to meet the requirements of Appendix F and PS-11), mercury, HCl, carbon monoxide (not required for units over 100 MMBtu/hr with CO CEMS), and dioxins/furans (D/Fs) on an annual basis for at least the first three years. 75 FR 32051-052. Thereafter, EPA proposes to reduce the frequency to three years if there have been three tests in a row that have results of less than 75 percent of the emission standard; however, EPA inexplicably does not provide this reduced testing option for dioxin/furan testing. 75 FR 32051. EPA also specifies each test must consist of three 4 hour runs. 75 FR 32052.

EPA states in the preamble to the Proposed Rule that the proposed compliance requirements "ensure compliance with the proposed rule without imposing a significant burden for facilities that must implement them." 75 FR 32033. We disagree with this statement. The proposed performance testing requirements do pose a significant burden.

This frequency of testing is unreasonable and out of character with other MACT and NSPS standards and other state performance testing requirements. EPA has proposed the most aggressive performance testing requirements we are aware of on the largest MACT source category it has addressed to date. The Hazardous Waste Combustor MACT (Subpart EEE), for example requires a Comprehensive Performance Test only once every 5 years. Many MACT standards and NSPS standards only require one initial performance test unless there is a physical change to the control device.

We recognize EPA has included a provision to skip to a three year frequency, but a source must pass three tests in a row with at least a 25 percent margin. Given the very stringent limits EPA has proposed, very few, if any units are likely to qualify for this provision, so we are not sure of its value.

EPA states in the preamble, "[a]dditionally, this proposed rule would require annual performance tests to ensure, on an ongoing basis, that the air pollution control device is operating properly and its performance is not deteriorating." 75 FR 32033. EPA is over-reaching with this argument. The continuous parametric monitoring requirements proposed in Table 8 of the Proposed Rule (fabric filter bag leak detection, electrostatic precipitator power input, opacity monitoring, wet scrubber pressure drop and flow rate, etc) provide ample assurance the control equipment is not deteriorating and are operated properly.

Our experience would indicate that EPA's cost estimate is low. CIBO members have paid about $20,000 just for D/F tests that included just 150 minute test runs during the 2009 ICR Phase II testing. CIBO would estimate about $60,000 to conduct the tests for PM, D/Fs, Hg, HCl. The requirement for 4 hour runs would required two testing days instead of one, running up costs considerably for a test, not to mention the logistical difficulties of successfully running a test and working around operational disruptions.

As discussed elsewhere in these comments, CIBO does not believe D/F standards should be set at this time. As far as we know, the only rationale for 4 hour runs is to achieve detection limits lower that the extremely low D/F standard proposed. From our experience, one hour test runs will be adequate to demonstrate compliance with the proposed emission standards for PM, HCl, and Hg.

B. Inaccuracies and Other Emissions Testing Methods For Final Rule.

The language in the Proposed Rule referencing the a "summary of the results of the performance tests" is inconsistent. Specifically, proposed §§ 63.7550(c)(5) and 63.7555(d)(6) refer to 90 percent emission limit threshold, while the proposed § 63.7515(b)-(c) refer to 75 percent of the emission limit. See 75 FR 32051 and 32061. EPA should include in the final rule specifications for minimum collection quantity and minimum test time for each test method. In addition, the final rule needs to specify how to handle detection levels and reporting of data that is detection level limited relative to compliance with emission limits.

EPA should include in the final rule additional options for mercury emissions testing. The Ontario Hydro Method is not considered accurate enough to guarantee mercury control performance at the extremely low proposed emission limit levels. Therefore, CIBO recommends that mercury emissions testing include Method 30A (Instrumental Analyzer) and 30B (Sorbent Trap Method). Finally, for units without PM CEMS, EPA should allow M5B for PM when using a wet scrubber.

XXII. Monitoring

A. EPA Should Clarify CO CEMS are not Required for Gas 1 boilers >100 MMBtu/hr.

The preamble to the rule indicates that the only requirements applicable to Gas 1 boilers are work practices. However, the proposed § 63.7525(a) provides "[i]f your boiler or process heater has a heat input capacity of 100 MMBtu/hr or greater, you must install, operate, and maintain a continuous emission monitoring system (CEMS) for CO and oxygen…." 75 FR 32055. As it is currently written this section would require CO CEMS for the Gas 1 subcategory. EPA has not established CO emission limits for the Gas 1 subcategory; therefore, it is not necessary to install CO CEMS. EPA should re-draft the proposed § 63.7525(a) so that it is applicable only if a unit has a CO limitation and a heat input of 100 MMBtu/hr or greater. Such clarification will ensure that unnecessary and costly requirements are not imposed on the Gas 1 subcategory or on Gas 2 units if numerical limits are not established.

1. Semiannual flow sensor calibration is too frequent and unjustified.

The Proposed Rule requires sources with an operating limit that requires flow measurement to "conduct a flow sensor calibration check at least semiannually." 75 FR 32056. This requirement is unreasonable because the calibration is too frequent. Electronic flow sensors have minimal drift and may not be able to do calibration without adversely affecting operation. CIBO recommends that EPA allow recalibrations be done on the normal unit overhaul frequency.

2. Daily check of pressure tap pluggage is onerous and unjustified.

Sources with operating limits that require the use of a pressure measurement device are required to "check pressure tap pluggage daily. 75 FR 32056. This requires gauging calibration with a manometer. 75 FR 32056. This requirement does not reflect common practice. CIBO recommends that EPA amend this requirement so that it is more flexible.

3. The pH meter calibration requirement is too frequent and unjustified

Sources with operating limits that require the use of a pH measurement device must check the pH meter's calibration on at least two points every 8 hours of process operation. 75 FR 32056. This requirement is excessive, as most facilities calibrate pH meters weekly. Autocalibration systems are available for around $30,000 per application, which adds to the already significant control, testing, and monitoring costs for this rule.

4. The sorbent injection rate monitoring requirements are too unreasonable.

Sources with operating limits that require the use of equipment to monitor sorbent injection rate (e.g. , weigh belt, weigh hopper, or hopper flow measurement device) must install and calibrate the device in accordance with manufacturer's procedures and specifications. 75 FR 32056. Additionally, on an annual basis, sources must calibrate the device in accordance with the manufacturer's procedures and specifications. 75 FR 32056. This requirement is unreasonable. EPA should allow units that do not shut down at least annually for a scheduled or code outage, to conduct this work on a frequency to coincide with scheduled maintenance or code outages. For any of the monitoring methods EPA should not require calibration more frequently than on an annual basis.

XXIII. Source Designation: § 112 and § 129, and the Definition of Natural Gas.

It is very important for a unit that would be regulated under the Proposed Rule to be able to move between regulations based on CAA § 129 when burning, and § 112 when not burning solid waste. Switching between fuels is a common occurrence among units, many of which only burn solid waste part-time. Having the appropriate regulations for the unit based on the fuel helps the unit be more cost efficient, and ensures that the relevant environmental concerns are being addressed. The preferred approach would be to allow units to select whether to be regulated by CISWI or Boiler MACT based on the materials being burned at any given time. EPA has taken this approach in the Hazardous Waste Combustor MACT (see 40 CFR 63.1206(b)(1)(ii)). It is a reasonable approach which has work well with HWC units and is needed when this rule is finalized. For those units, requirements for incinerators under Subpart EEE apply except when hazardous waste is not in the combustion chamber. The unit then must comply with application requirements under § 112. 40 CFR § 63.1206(b)(1)(ii)). With this established procedure, EPA should likewise allow units that burn solid waste part-time to switch modes of operation between CISWI or Boiler MACT.

Another important scenario that EPA needs to account for in the Proposed Rule is to permit sources to discontinue reliance on materials and thereby remain boilers or be re-categorized as boilers. Where that unit has in the past burned materials that EPA now or in the future determines to be solid waste, the unit must be permitted to be categorized as a Section 112 boiler if it discontinues using the materials as fuel. Because any time in the future EPA could make a determination that a material is a waste and not a fuel, a source needs to determine whether compliance with section 129 standards is feasible. If the source decides it is infeasible, then there is no legal barrier -- nor is there a legal reason for EPA to erect one -- to the source ceasing use of that fuel material, and complying with section 112 standards.

As units switch from solid waste to other fuels, forbidding them from switching to regulation under the Proposed Rule unfairly punishes them, and discourages switching to cleaner fuel. There would be no environmental benefit from requiring them to continue to comply with section 129 rather than section 112. For example, a unit currently operates coal-fired boilers that periodically run in an operating mode where a wastewater treatment sludge is co-fired with the coal. During this mode of operation, NOx emissions drop significantly. This should be regulated in accordance to the potential for which emissions would be released, and can be easily documented by the facilities based on which mode of operation they are in.

In the Proposed CISWI Rulel, EPA recognizes that energy recovery units such as boilers differ fundamentally from incinerators and that "differences can result in emission profiles for energy recovery units that are different from incinerators but similar to boilers." 75 FR 31951. EPA recognizes that if a unit stops burning solid waste, it would no longer be subject to §129. 75 FR 31942. This reflects the statutory scheme. Congress expressly made §112 and §129 mutually exclusive, keeping the source categories separate and ensuring that only one set of emission standards applies to the source at one time. Therefore, the only question is the frequency with which a source switches from solid waste to other fuels. The final rule should ensure that sources may use alternative fuels as available, and comply with the corresponding standard.

When this occurs, and a unit switches from solid waste to another fuel, the applicability definitions of both § 112 and § 129 of the CAA should be interpreted to ensure that the unit would be classified as an existing (not new) source under the regulations. This will avoid unfair punishment for a unit making such a switch, and help to encourage the burning of cleaner fuels.

Allowing for this flexibility in the selection of regulations would be able to work with no major problems in practice. The unit's permit would have simply have two sets of standards which would be applicable at different times based on the fuel being burned. This would be easily be monitored by tracking solid waste feed rates and units would readily be able to show compliance with the applicable standard. In terms of other regulatory provisions of the regulations, such as certified technicians and monitoring requirements, units should follow the regulation of the fuel which they burn the majority of the time. This would help to minimize the confusion of following two separate regulations, while ensuring that units are still adequately regulated.

Allowing for maximum fuel diversity is important, including alternate and opportunity fuels. In the Proposed CISWI Rule, EPA is proposing a definition of a CISWI unit, however CIBO believes it is inappropriate to apply RCRA hazardous waste approaches to non-hazardous materials, because the non-hazardous materials do not present the inherent risks associated with hazardous materials. Energy recovery from non-hazardous materials is in the overall best interest of the US and any resulting air emissions will be well controlled under § 112 standards. CIBO has filed more expansive comments on this topic in response to the proposed Solid Waste Defiinition Rule and hereby incorporates those comments by reference. CIBO comments on the Solid Waste Definition Rule are included as Attachment 3. This is especially important if EPA intends to finalize provisions that require sources regulated under §112 to conduct an energy assessment, which includes identifying ways to increase plant energy efficiency.

EPA has simultaneously proposed the Proposed Rule, the Proposed CISWI Rule, the Proposed Area Source Rule and the solid waste definition. However, based on the final rule determining what is or is not a solid waste, sources will likely adjust their plan for use of alternative fuels that may be redefined as wastes in the final rule.

CIBO members are concerned that the true composition of the source categories for floor setting in the standards rules will not be known until the solid waste definition is finalized. At that point, CIBO members view it as an unavoidable outcome that EPA will need to recalculate floors for the air emission standards rules. If that should happen, then the compliance deadlines for those rules, and the effectiveness date for this rule, will be in question. EPA should make clear in the final rule what those dates will be and how it expects the rules to interrelate from a compliance perspective. Facilities need to know when a material they currently burn as a fuel must be discontinued if they decide that the hurdle to showing it is a fuel rather than a waste is too high despite its fuel value. That date should be the compliance date of the air emissions standard rule for the source.

A provision should be added that allows a facility to elect to either (1) comply with CISWI at all times or (2) comply with CISWI while burning solid waste but comply with otherwise applicable standards under section 112 of the Clean Air Act while not burning solid waste. For example, CIBO-member Eastman operates coal-fired boilers that periodically run in an operating mode where a wastewater treatment sludge is co-fired with the coal. During this mode of operation, NOx emissions drop significantly. Section 129 of the Clean Air Act requires EPA to set emission standards for sulfur dioxide and NOx under CISWI and such standards are not required under the Boiler and Process Heater MACT.

Depending on the stringency of the CISWI NOx emission standard, it may not be possible to comply with the NOx standard while operating in the coal-only mode without installing emission controls that are not otherwise authorized under the Clean Air Act. There will likely be other situations where burning solid waste results in lower emissions than burning 100 percent fuel and facilities should not be penalized for these circumstances. Facilities can easily document which mode of operation they are in (by tracking solid waste feed rates) and readily show compliance with the applicable standard.

A. The Definition of EGU is Incorrect When Compared to the Definition in § 112.

Facilities need clarity on the affected sources under industrial boiler MACT versus the utility boiler MACT that EPA is currently developing. EPA has traditionally defined electricity generating units (EGUs) to be those units that are constructed for the purpose of supplying more than one-third of their net potential electric output capacity and more than 25 MWe to any utility power distribution system for sale. In fact, Congress used nearly identical language when excluding cogeneration units from the definition of "utility unit" under the Acid Rain Program. See 42 U.S.C. § 7651a(17)(C).

Utilization of the traditional definition of EGU is appropriate in this rulemaking and that EPA should make the distinction between utility and industrial units clear in the final rule so facilities can have a clear path forward for determining which rule covers their boilers. The definition of EGU in the Proposed Rule is not complete. The above definition of EGU recognizes the difference between large, stand-alone electric generation stations and large industrial cogeneration facilities. Indeed, there are important reasons for regulating these types of units differently, not least of which is the fact that cogeneration facilities have already achieved substantial reductions in emissions by using the same fuel combustion to generate electricity and to generate needed thermal energy for industrial processes or commercial activities.

XXIV. Exemptions

A. The Hot Water Heater Exemption Should Be Expanded.

The Proposed Rule provides an exemption for hot water heaters. 75 FR 32050. EPA defines hot water heater under the Proposed Rule to mean

> a closed vessel with a capacity of no more than 120 U.S. gallons in which water is heated by combustion of gaseous or liquid fuel and is withdrawn for use external to the vessel at pressures not exceeding 160 psig, including the apparatus by which the heat is generated and all controls and devices necessary to prevent water temperatures from exceeding 210° F (99° C).

75 FR 32064. This definition should be expanded to include natural gas or distillate fuel oil fired circulating hot water systems no larger than 10MMBtu/hr heat input that are used for domestic (e.g., washroom, cafeteria) or space heating purposes. This would eliminate the need to spend time or effort on units with insignificant emissions.

B. The Exemption for Sources that Burn a Single Type of Fuel Should Be Expanded.

The Proposed Rule provides that "affected sources that burn a single type of fuel" are exempted from "the initial compliance requirements of conducting a fuel analysis for each type of fuel burned [in the] boiler or process heater. 75 FR 32051. This exemption should be included in the proposed § 63.7521. 75 FR 32052. For additional clarity, the proposed § 63.7540(a) should reflect the language in § 63.7510(a) exempting sources that burn single type of fuel from initial compliance requirements.

C. Fuel Sampling and Analysis Requirements Should Apply Only to Solid or Liquid Fuels.

EPA should amend the Proposed Rule so that it clearly states that fuel sampling and analysis requirements are applicable only to solid or liquid fuels. Furthermore, EPA should clarify under what circumstances liquid fuel analysis is required.

D. Exemptions From the Prior Rule and Others.

There are several exemptions that were included in the prior boiler MACT rule that should be added to the exemptions list when this rule is finalized. Specifically, EPA should include an exemption for the following:

1. municipal waste combustors covered by 40 CFR part 60, subpart AAAA, subpart BBBB, subpart Cb or subpart Eb;
2. hospital/medical/infectious waste incinerators covered by 40 CFR part 60, subpart Ce or subpart Ec.

Additionally, in the preamble to the Proposed Rule, EPA indicates its intention to have affected source not include boilers and process heaters "subject to another standard under 40 C.F.R. part 63 or a standard established under CAA § 129." 75 FR 32011. However, section 129 is not specifically listed in the exemptions section under the proposed §63.7491. EPA should include a general statement similar to that for 40 C.F.R. 63(i) relative to § 129 in the final §63.7491. Alternatively, EPA should list specific rules.

It appears the exemption provided under the proposed §63.7491(i) may be intended to cover all units subject to other 40 C.F.R. 63 regs, including hazardous waste combustors and BIFs. However, the Proposed Area Source Rule includes language that should be included in this Proposed Rule. Specifically, the Proposed Rule should include the following language "(c) A boiler required to have a permit under section 3005 of the Solid Waste Disposal Act or covered by subpart EEE of this part (e.g., hazardous waste boilers)." 75 FR 31925. EPA should also provide exemptions for duct burners on turbines.

XXV. Compliance Timeline

A. Compliance Deadline for Existing Sources.

EPA proposes to set the compliance deadline for existing affected sources at three years after the date of publication of the final rule in the Federal Register. 75 FR 32035. This provides an inadequate amount of time for the thousands of affected sources to be retrofitted as necessary to meet the new MACT standards. EPA estimates that 3,730 existing units will have to come into compliance with the proposed MACT standards. This is an unprecedented number of sources impacted by a MACT ruling. These units are all solid fuel-fired, i.e., predominantly coal-fired, units. In order to meet the MACT standards, owners will, by and large, have to install add-on controls.

We anticipate that industry will face severe time and material constraints that will make it extremely difficult, if not impossible, for many facilities to meet the retrofit deadline of three years. Most of the targeted solid fuel- fired units are located at facilities that will have to undergo substantial re-engineering, e.g., due to space constraints, to accommodate new controls. Design, procurement, installation, and shakedown of these projects will easily consume three years. In short, more time is needed. External factors will also jeopardize compliance within three years. A large number of companies will be competing nationwide for limited resources and materials from engineering consultants, equipment vendors, construction contractors, financial institutions, and other critical suppliers. This competition for limited resources will be compounded by the promulgation of the Clean Air Transport Rule, the Utility MACT, Regional Haze SIP's and/or FIP's at roughly the same period of time, which will introduce competition from electric utilities in addition to competition from other industrial boiler owners. Much of the pollution control equipment may not even be available within EPA's proposed compliance timeframe. By extending the compliance time, EPA would allow for the development of new creative technology to provide superior emissions control

It is likely many companies will find themselves unable to procure the necessary goods and services to complete the retrofitting of their affected units within three years. In particular, we anticipate problems procuring baghouses and scrubbers because immediate industry demand will outstrip immediately available supplies. For example, in preparation for compliance with the prio MACT, a scrubber project at one of CIBO's member facilities took four years to implement. Industry must continue to operate as best as possible while retrofitting to meet the new MACT standards. Construction on units will need to be staggered as facilities with multiple units will require equipment to be installed with units out of service. Staggering work on separate units a the same facility allows continued operation; however, this staggering extends the overall compliance time.

In general, the existing solid fuel-fired boilers that will be subject to this new rule comprise the most critical part of the base load energy supply for their facilities. These units typically have high capacity utilization rates. Extensive outages for retrofitting must be carefully planned. Only when all of the critical prerequisites for the retrofit have been lined up, e.g., the engineering is complete and the control equipment is staged for immediate installation, can an owner afford to shut down a facility's base load boiler to install the new controls. This takes planning and coordination both within the company and contractors.

Many units must conduct emissions testing prior to retrofitting units in order to determine the best means of achieving compliance. There are a limited number of emission testing contractors and laboratories capable of conducting this type of testing, which will further the delay. Where testing determines that emission limitations are unachievable and retrofitting is infeasible, it is possible they will decide to re-power or switch fuels. These additional processes would surely extend beyond the three year compliance timeframe proposed by EPA. Even under the best case scenario, undertaking a retrofit can take five years. Three years is simply not sufficient to allow owners of many of the affected sources the time necessary to make the retrofits without substantial disruption to the operation of their facilities.

The process to undertake a retrofitting project is more complex then EPA appreciates. Regulated sources need time to obtain capital funding. Some facilities will have to obtain capital funding for these projects thru a formal request process that by itself could last two years. Those facilities reliant upon the state funding process can only seek legislative approval when the rule is final.

Finally, we remain concerned about the ability of small businesses to comply with the proposed standards within three years. The monetary impact on small businesses will be substantial enough to strain their financial well-being. The present sluggish economy simply does not provide the financial resources for many of these small companies to take on the additional costs of retrofits to meet the proposed MACT standards in three years. More time is needed.

We recommend EPA address the foregoing problems by extending the compliance deadline to four years after the publication of the final regulations in the Federal Register. We believe the Agency would be fully justified in invoking § 112(i)(3)(B) to grant owners of all affected sources a one-year extension of the compliance deadline. Four years would provide critically needed time for industry to conduct the necessary retrofitting with controls and absorb the great cost of these retrofits. Given the magnitude of the retrofit requirements and the likelihood of substantial difficulties fulfilling these requirements, it is essential that EPA provide whatever relief may be possible.

There is established precedent for allowing sources more time to comply. Specifically, the final NESHAP for the Pulp and Paper Production source category includes an eight year compliance deadline. 63 FR 18519. Additionally, EPA extended the compliance date for the miscellaneous organics chemical manufacturing (MON) MACT. That standard was challenged in court with EPA and industry agreeing to a settlement. As part of the settlement, EPA extended the compliance deadline.

B. Additional Options For Compliance Demonstration.

The general compliance plan outlined in the Proposed Rule is that sources (1) demonstrate compliance with applicable emissions limitations and work practice standards through the conduct of an initial performance test; (2) establish operating limits based upon results of the performance test; (3) conduct monitoring and maintain records demonstrating that the source is operated on a continuous basis consistent with the operating limits established during the performance test; and (4) periodically repeat the performance testing. For operating parameter limits based on fuel input analysis (e.g., HCI, metals, Hg), operating limits are established using Equations 1,2 or 3 in 63.7530. Then, on a continuing basis, sources are required to keep extensive records of all fuels burned (i.e., fuel type, fuel supplier, fuel mixture, fuel supplier and source, and fuel usage amount) in each boiler or process heater during each compliance reporting period. If a source changes fuels (type, supplier, etc.), it must re-calculate operating limits using applicable equation 1, 2, or 3. If the re-calculated limit exceeds the existing limit, the source is required to conduct a new performance test and establish new operating limits.

While this compliance scheme may be appropriate for some sources, especially ones with very stable fuel supply and usage, it may be very cumbersome and burdensome for other sources. It involves a great deal of recordkeeping and potentially subjects the source to frequent testing requirements. As an example of the complexity this proposed compliance plan involves, Section 63.7550 (c)(4) requires that among other things, the semi annual report is to have "the supplier of the fuel and original source of the fuel." To make the proposed compliance plan work (which CIBO does not believe can be done), the Agency would have to be much more explicit for instance in its definition of the original source of the fuel. And that definition would need to consider as many contexts as exist in the market for fuel generation, distribution, and delivery; e.g., if the fuel is a process fuel generated internally, if the fuel is from a distributor or supplier, and if the fuel is pulled from commercial pipelines that may receive input from numerous companies in varying amounts over rime." It appears that the objective for the operating limits that are based on fuel analysis is to insure that the pollutant (chlorine, metals, mercury) input to the source for a given level of operation does not exceed the input level demonstrated during the performance test, where compliance with emissions limitations and work practice standards was demonstrated.

There are several ways in which this objective can be achieved, in addition to the single compliance method proposed. As an example, compliance could be demonstrated through the use of fuel purchase specifications. Sources would determine from the performance test a maximum fuel pollutant concentration at which the emissions limitations and work practice standards are achieved. For instance, the performance test may demonstrate that fuels containing chlorine in concentrations less than x IbCI/MMBTU allow the source to comply with emissions limitations. The source would then set a fuel specification of x IbCI/MMBTU and would be allowed to burn any fuel of the same general type (e.g., solid, liquid or gas) as long as it met this specification. Sources could require that the fuel supplier provide periodic certification that the fuel meets the specification, based on analysis, or could establish an internal sampling and analysis program for that purpose. In any case, where common fuels are utilized in more than one unit, common fuel quality data should be maintained and considered applicable to all such units. Continuous compliance could also be demonstrated through ongoing fuel analysis according to applicable Equations 1, 2 or 3 in § 63.7530.

As an example, sources would (1) establish a fuel input limit (e.g., IbCl/MMBTU) based on the compliance test as described in the proposal (with an allowance for extrapolation as proposed by CIBO elsewhere in these comments); (2) periodically sample and analyze each fuel for constituent concentration and heating value according to a specified sampling and analysis plan; (3) monitor the daily usage of each fuel; (4) calculate the average total daily constituent input (lb/MMBTU) accounting for all wastes fed; and (5) demonstrate that the average daily constituent input rate averaged over each month of operation does not exceed the operating limit. This option would afford the source the opportunity to vary fuel mixes, while still insuring that protective operating limits are met.

Given the wide variety of sources impacted by this proposal, it is reasonable to provide flexibility in how sources demonstrate compliance, as long as clearly-defined compliance objectives are met. CIBO requests that EPA include the compliance schemes discussed above in the final rule as allowable optional compliance strategies. We are willing to work with the agency to further refine these strategies. Additionally, CIBO requests that the final rule include an allowance for a source to use, with prior Agency approval, other compliance strategies that may be more appropriate on a site-specific basis.

XXVI. Emission Reporting Tool (ERT) Problems

EPA is requiring submission of data via the Electronic Reporting Tool (ERT). 75 FR 32015. Notwithstanding EPA's assertions to the contrary, data submitted through the ERT is error-prone and imposes additional burdens on reporting sources because the ERT bypasses all data quality control. For the information collection process for the Boiler MACT suite of rules, EPA required sources to use the ERT. Sources had requested in the ICR proposal stage that EPA not utilize the ERT, which was going through Beta testing, and informed EPA that the ERT had serious flaws including difficulty of use, content problems and inaccessibility. EPA decided to use it for data collection for these rules. The concerns proved correct, however, as sources were compelled to use the ERT, which is a difficult and time-consuming tool for submission of test data. The ERT data compiled was riddled with mistaken entries, incorrect and missing data, and the ERT had generally faulty output. Then the problem was compounded when EPA relied on the inaccurate data, leading to multiple calculation and other inaccuracies.

Using the ERT doubles the burden on sources that take the time to enter accurate source data, only to see it distorted. They then must spend hours finding the data error and conferring with EPA personnel to fix the problem. Only then are they able to consider EPA's rule proposal and its impact on their sources. In part due to the ERT and resulting data problems, regulated sources sought an extension of the comment period. *See* Comment Extension Request, especially Description of the Development of the Boiler MACT Database (Attachment 1).

In the past, sources did compliance tests for the state, and the state approved the data. The state effectively conducted quality control on the data. The ERT bypasses the state, creating data quality issues. Using the ERT means that data is transmitted without any QC, and that results in multiple data errors. The ERT does not permit the easy identification or correction of errors. Reporting needs to be accomplished by whatever format permits the source to trace the same data throughout the process to ensure its integrity. This had been accomplished in the past by using the hard copy submitted to the State and a human being looking at data to QC it. If there was a problem, this could be identified and resolved in the early stage, before the faulty data was applied to formulas.

CIBO urges EPA to adopt a reporting methodology that ensures the data is quality controlled, and errors can be traced easily to their origins. The ERT needs to be improved before it is required for data submission for compliance demonstration. Inaccuracies may be more tolerable during the rule-writing process, but once the rules are in place, the stakes are much higher, as faulty ERT output can create compliance issues for sources. EPA may prefer the administrative ease of the ERT, but that should not outweigh the need for regulated sources to have assurances of accurate data and compliance status.

XXVII. Notifications

Under the Proposed Rule, an owner or operator would be required to submit notifications based on the schedule set forth in proposed § 63.7545. 75 FR 32060. The Proposed Rule is not clear whether another initial notice is required for units that filed under the prior Subpart DDDDD. EPA should clarify whether an additional notice is required for units that filed under the prior Subpart DDDD.

XXVIII. Recordkeeping

A. Continuous emission monitoring systems (CEMS) in lieu of performance testing and continuous parametric monitoring (CPMS).

While the Proposed Rule mandates use of a PM CEMS for units over 250 MMBtu/hr rated heat input, it does not allow the option to use CEMS in lieu of performance testing, COMS, and CPMS. The NSPS for Hospital/Medical/Infectious Waste Incinerators (see FR 51368, Oct. 6, 2009) includes such a provision (see §60.56c(b)) for PM, D/Fs, HCl, and mercury. This rule also allows CEMS to be used in lieu of CPMS (see §60.57c(a)). Likewise, the proposed CISWI rule (page 31961) allows units using PM CEMS to be exempt from annual performance tests and opacity monitoring. Similar provisions should be included in the Boiler and Process Heater MACT.

B. SO2 CEMS data demonstrating removal of SO2 should be allowed to demonstrate compliance with HCl standard.

CIBO represents members that operates coal-fired boilers equipped with spray dryer absorbers (SDAs) to comply with SO2 emission rates. Since HCl is easier to absorb than SO2, if a unit is achieving significant SO2 removal, it can be concluded that HCl is being removed at an even higher efficiency. The results of the 2009 ICR Phase II performance test conducted on one of these boilers illustrate this relationship between SO2 removal and HCl removal very well. The SO2 removal during this test was 77 percent whereas no HCl was detected and an HCl removal efficiency is estimated at 99.4 percent assuming HCl was present at detection limits. In a case like this, a SO2 CEMS is a very good indicator of HCl removal and should be allowed to be used in lieu of scrubber parameter monitoring. EPA's proposal to require sorbent input rates to an SDA to meet or exceed the rates demonstrated in the performance test will be problematic and could result in a waste of sorbent.

C. CEMS, COMS, or CPMS Regarding Deviations.

The provision that any period of CEMS, COMS, or CPMS out of control or loss of data is a deviation is unreasonable and inconsistent with other monitoring requirements typical for CEMS. The Proposed Rule provides that "[a]ny period for which the monitoring system is out of control and data are not available for required calculations constitutes a deviation from the monitoring requirements." 75 FR 32055. There is a similar provision for COMS. 75 FR 32055. With the understanding that any well maintained CEMS or COMS will inevitably have periods where it is out of control or out of operation, we believe this provision is unreasonable. Many other regulations recognize this and build in some reasonable tolerance for missing data.

Typical state permit conditions require data availability for a minimum percentage of operating hours in a calendar month or quarter. The minimum percentage depends on the CEMS technology. Some monitors such as opacity can reasonably obtain a 95 percent availability. Regarding CPMS, the HON (40 CFR 63 Subpart G), for example, only defines a deviation (excursion) as an operating day where less than 75 percent of the parametric data is captured. We note that the proposed CISWI regulation provides for minimum data availability (see proposed §60.2735It would be capricious of EPA to set a monitoring requirement that cannot possibly be complied with 100 percent of the time. EPA should revise the rule to allow for reasonable amounts of missing data.

XXIX. Energy Assessment

For major sources, EPA has proposed as beyond-the-floor control technology an "energy assessment," defined as an "in-depth energy study identifying all energy conservation measures appropriate for a facility given its operating parameters." 75 FR 32014.

EPA proposes to require all owners or operators of major source facilities having boilers and process heaters to submit documentation that an energy assessment was performed, by qualified personnel, and the cost-effective energy conservations measures were identified. *Id.* at 32,012. EPA proposes a number of procedures for the energy assessment, including not only visual inspection of the boiler itself (*i.e.*, the regulated source) but also the "boiler system," and an extensive assessment of the "major energy consuming systems" (*i.e.*, unregulated sources and non-sources at the facility), including a review of "available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage." *Id.* at 32,014. Under EPA's proposal, regulated entities would be required to subject to an examination by a third party, not only the affected source itself, but also other non-covered units at major source location of the covered source. The rule requires the submission of a "comprehensive report" and "facility energy management program."

A. EPA Lacks Authority to Compel an Energy Assessment, Which Covers Units Not Subject To § 112, And Which Is Not an Emission Standard.

1. The assessment covers units that are not ICI boiler or process heater "affected sources"

EPA's authority under § 112 is to establish NESHAPS for industrial, commercial and institutional boilers and process heaters (ICI boilers and process heaters). By its own terms, the rule covers "affected sources" defined as all existing and new ICI boilers and process heaters located at major sources. 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. This is consistent with the long-established understanding of the term "affected source" as it relates to the "major source" where the affected source is located. See preamble to rule establishing the General Provisions for all NESHAPs, 59 FR 12,408, 12,412-13 (March 16, 1994).

Limiting the regulation to the affected source is also consistent with Congress's general statutory scheme, under which EPA is to publish a list of "all categories and subcategories of major sources and area sources" of the listed HAP. §112(c) (1). EPA's published list of source categories groups every conceivable type of industrial process and process unit into a category, each of which is regulated by its own NESHAP, each published as a separate Subpart to 40 C.F.R. Part 63. Therefore, any § 112 source other than the boiler and process heater affected units for this NESHAP is covered separately by another NESHAP. The statutory scheme does not assign duplicative source category regulations for the same unit.

Since 1992, the sources to be regulated relevant to this rule have been "industrial boilers," "commercial/institutional boilers," and "process heaters." 57 FR 31591. In this rule, EPA defines each of these sources. An industrial boiler is "a boiler used in manufacturing, processing, mining, and refining or any other industry to provide steam, hot water, and/or electricity." A commercial/institutional boiler is "a boiler used in commercial establishments or institutional establishments such as medical centers, research centers, institutions of higher education, hotels, and laundries to provide electricity, steam, and/or hot water." A process heater is "an enclosed device using controlled flame, that is not a boiler, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not directly come into contact with process materials." 75 FR 32063 - 65.

However, EPA's proposal extends well beyond regulation of "sources" and compels regulated entities to investigate, monitor and report activity at facilities unregulated by § 112 or even by the Clean Air Act. EPA proposes to require the assessment be made on the "boiler system," defined as "the boiler and associated components, such as, the feedwater system, the combustion air system, the fuel system (including burners), blowdown system, combustion control system, and energy consuming systems." 75 FR 32063. This definition is open-ended and covers units that are not part of the affected source for §112 purposes. The proposal further requires sources to consider, inter alia, the "operating characteristics of the facility, energy system specifications, operating and maintenance procedures, and unusual operating constraints. . .;" "major energy consuming systems;" "available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage. . .;" and to identify "major energy conservation measures." 75 FR 32014. EPA's authority is limited to setting emission limits for the affected combustion unit and does not extend to components not immediately associated with the combustion unit, nor to the energy using process areas. What EPA requires goes far beyond its authority.

The practical effect of the proposal is that, under the guise of reducing HAP emissions from boilers, universities will have to conduct broad reviews of campus building design and operations to seek ways to reduce energy use. Paper mills will have to look at pulp production and processing and paper manufacturing. The assessment is applicable not to the boiler at the university, but to the university itself; not to the boiler at the paper mill, but the paper mill itself. These are not "affected sources" but rather facilities at which sources are located. EPA is not entitled to read into the statute a roving mandate to review any possible unit, system, or opportunity to reduce energy consumption. Weatherization of classrooms may indeed reduce the demand for heat, but classrooms are not subject to §112.

2. The assessment is not an "emission standard"

Section 112 requires EPA to establish "emission standards" for each listed source category and subcategory. §112(c)(2); 42 U.S.C. § 7412(c)(2). By definition, the identification of energy saving measures is not an emission standard. In addition, were the efficiency measures actually to be undertaken, reduced demand for the output of a regulated source is not an "emission control" technology to limit emissions from the regulated source. §112(c)(2); 42 U.S.C.

§ 7412(d)(3) If this were so, the text of §112 would provide no limiting principle for EPA's authority.

EPA finds justification for the energy assessment by defining it as a beyond-the-floor control technology in CAA section 112(d)(2):

> Emission standards promulgated…and applicable to new or existing sources…is achievable…through application of measures, processes, methods, systems or techniques including but not limited to measures which…reduce the volume of, or eliminate emissions of, such pollutants through process changes, substitution of materials or other modifications.

75 FR 32,026 (citing 42 U.S.C. 7412(d)(2)). EPA posits that "process changes, substitution of materials or other modifications" encompasses "energy assessments." However, when the statute refers to "process changes, substitution of materials or other modifications" it can only be referring to the source "to which such emission standard applies." §112(d)(2). And it can only apply to methods to achieve the emission standards.

Yet EPA's proposal extends well beyond reduction of emissions by "sources" and seeks to compel regulated entities to investigate, monitor and report activity at units unregulated by the Clean Air Act. The proposal requires sources to consider, inter alia, the "operating characteristics of the facility, energy system specifications, operating and maintenance procedures, and unusual operating constraints. . .;" "major energy consuming systems;" "available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage. . .;" and " major energy conservation measures." 75 FR 32014. As defined in the rule, the energy assessment would require "a thorough examination" of a site far beyond the § 112 affected source: "Energy assessment means an in-depth assessment of a facility to identify immediate and long-term opportunities to save energy, focusing on the steam and process heating systems which involves a thorough examination of potential savings from energy efficiency improvements, waste minimization and pollution prevention, and productivity improvement." 75 FR 32064. EPA must limit regulatory requirements to methods that will reduce HAP emissions by the regulated combustion unit itself and not to other systems, energy using systems or process areas. EPA goes beyond its authority by imposing requirements beyond the combustion unit, even covering systems not directly associated with combustion units.

Moreover, EPA improperly identifies the energy assessment as a beyond-the-floor standard. This is not consistent with the text of the CAA, which as EPA explains, requires it to consider control options that are "more stringent" than the MACT floor. 75 FR 32008. An energy assessment does not purport to limit emissions, nor impose more stringent standards than the MACT floor.

EPA has developed MACT standards that allow sources to elect to comply with pollution prevention alternatives in lieu of standards for some units and under certain circumstances. See, e.g., Pharmaceuticals Production MACT, 40 C.F.R. Part 63, Subpart GGG; National Emission Standards for Hazardous Air Pollutants for Source Categories: Pharmaceuticals Production; Final Rule, 63 FR 50280 (Sept. 21, 1998)(Pharma MACT). These do not, however, establish analogous precedent for the action EPA proposes in this MACT. The provisions of the Pharma MACT, for example, are a compliance alternative to compliance with the MACT standard. Here, EPA defines this as a beyond-the-floor MACT standard, making it not only mandatory, but also grounding it in the notion that sources can and must achieve by its greater stringency than the floor, greater emission reductions. In addition, the Pharma compliance alternative relates directly to the reduction of the regulated pollutants from the same four regulated source types as those regulated by the MACT standard. Here, no such direct correlation can be made, and the assessment covers unregulated, non-emitting elements of the company's operation beyond the regulated boiler and process heater.

In another section of the rule, EPA identifies the energy assessment as a work practice standard, including it in Table 3, entitled "Work Practice Standards." 75 FR 32068. Authority to require work practice standards derives from § 112(h), and EPA does not provide any legal justification for the energy assessment as a work practice. Its inclusion in Table 3 appears to be in error, but in any event, EPA lacks statutory authority to require the assessment as proposed under any provision of the CAA.

B. The Assessment is Arbitrary Because it Lacks a Relationship to HAP Reduction, and EPA Provides No Record Basis Demonstrating Such a Relationship.

EPA states that "[t]he purpose of an energy assessment is to identify energy conservation measures (such as, process changes or other modifications to the facility") that can be implemented to reduce the facility energy demand which would result in reduced fuel use. Reduced fuel use will result in a corresponding reduction in HAP, and non-HAP emissions." 75 FR 32,026. The problem with this assertion is that in many cases it is simply not true.

The simple comparison of two boilers – one using coal and one co-firing coal and bark – demonstrates EPA's misdirection on this issue. In this example, an energy efficiency audit would show that a boiler using only coal is more efficient than a boiler using bark and coal, due to the higher moisture content in bark. However, a boiler using only coal would have increased emissions.

Reduced energy does not necessarily mean reduced pollutant emissions, even if it means reduced HAP emissions from the boiler. To offer but one specific countervailing example: periodic operation of solid fuel boilers in a highly turned down mode is common among many industrial sectors, as an efficient way to manage manufacturing process energy needs. For example, industrial process boilers in the wood products industry supply steam according to the immediate demand from processes for which they are operated. These boilers operate at widely varying load levels, depending on, among other things, the amount of steam the process equipment is demanding at the time. During high turndown periods the actual HAP emission load should be lower since the total fuel load is reduced from the normal operation. Conversely, however, high CO emissions are a common occurrence to all solid fuel boilers during high turndown operation due to a combination of well-known combustion fundamentals. It is impossible to avoid these countervailing effects. EPA has recognized boiler, or burner, turndown ratio as a factor affecting performance in several contexts. See, EPA, Final Technical Support Document for HWC MACT Standards, Vol. IV, p. 3.6 (July 1999); EPA Region 6 Center for Combustion Science and

Engineering, Hazardous Waste Combustion Unit Permitting Manual, Component 1 How to Review a Test Burn Plan, p. D-5.5 (Tetra Tech Jan. 1998).

In addition to a turndown resulting in increased non-HAP emissions from the boiler, in other scenarios, reduced energy could result in increased HAP emissions from other non-combustion processes. In fact, in this proposal, EPA acknowledges that categorical assertions regarding energy-pollutant emissions relationships are not accurate, when it notes that "[i]mprovement in energy efficiency results in decreased fuel use which results in a corresponding decrease in missions (both HAP and non-HAP) from the combustion unit, but not necessarily a decrease in emissions of all HAP emitted." 75 FR 32,026.

Teeing energy assessments (EAs) to finite HAP limits implies that the Energy Intensity (EI) of the processes served by the ICI boiler is a static quantity and that the incremental improvement brought about by the implementation of opportunities discovered by the EAs would therefore incrementally reduce HAP emissions. This could not possibly be more incorrect. The EI of a facility depends on many constantly changing factors, including environmental conditions, raw material quality, product output, and others. Further, facilities may have hundreds of different products that are produced in ever-changing combinations. These products may have individual EIs that are one, two, three, or more orders of magnitude different. Thus product mix only further complicates the already dynamic nature of a facility EI. Further, a specific energy improvement opportunity may only affect the production of one specific product or may only apply during certain environmental conditions, and thus its effect would be affected by the same dynamic factors as the overall EI.

EPA has not proposed this concept in any other MACT standard for any other regulated sector, nor should it. Boilers provide a single product—heat—to a tremendous number of consumers in hundreds of different contexts. The product consumed is often in some proximity to the boiler itself, which makes it conceptually appealing for EPA to imagine the efficacy of the "energy assessment." But certainly EPA would never impose such a requirement on other sectors regulated under § 112, because the absurdity of the proposal would be highlighted. For example, we doubt that EPA would ever propose that entities owning surfacing coating facilities for metal furniture (40 C.F.R. 60.310 et seq.) review their "demand" for such surface coating. EPA has promulgated MACT standards for five different sources common to the phosphate fertilizer industry (40 C.F.R. Subpart T through Subpart X) but would never demand that the phosphate fertilizer industry identify a "more efficient" phosphate fertilizer. Yet less demand for surface coating for metal furniture, and less demand for the chemicals produced by sources regulated under Subparts T through X, would according to EPA's logic reduce the demand for the products produced by sources regulated under section 112, thereby limiting inputs and thereby reducing HAPs. EPA has arbitrarily picked one product out of the thousands produced by sources regulated under § 112 and demanded that regulated entities identify ways to make less of it.

EPA does not and cannot demonstrate that conducting an energy assessment will actually reduce HAP emissions. Similarly, EPA does not and cannot demonstrate that even implementing the findings of an energy assessment, assuming EPA were to require implementation, will reduce HAP reductions. EPA admits as much in the proposal, offering unsubstantiated projections of possible reductions as support:

> If a facility implemented the cost-effective energy conservation measures identified in the energy assessment, it would potentially result in greater HAP reduction than achieved by a boiler tune-up alone and potentially reducing HAP emissions (HCl, mercury, non-mercury metals, and VOC) by an additional 820 to 1,640- tons per year.

75 FR at 32,026 (emphasis added).

Notwithstanding no demonstrated correlation between yet-unidentified energy saving measures and projected possible HAP reduction, and no proposal to require their implementation, EPA offers this flawed syllogism: an energy assessment identifies ways to reduce fuel use; reduced fuel use will reduce pollutant emissions; therefore an energy assessment will reduce HAP emissions consistent with 112(d)(2). 75 FR 32026. The proposal irrationally concludes that an energy assessment will contribute to achieving the maximum HAP emission reduction. 75 FR 32026. In fact, an unimplemented energy assessment will not reduce fuel use, will not reduce HAP emissions, and even if implemented, will not reduce HAP emissions consistent with 112(d)(2).

C. Any Possible Energy and Cost Savings From the Energy Assessments Cannot Be Projected Reliably and the Proposed Rule Irrationally Presumes Such Savings.

EPA presumes HAP reductions and energy and energy-related cost savings from implemented energy assessments 75 FR 32026 (estimating HAP reductions of 820 – 1640 tons per year). Each of these presumptions is unreliable, due principally to the diversity and complexity of the source category. As described above, at some facilities, reduced fuel consumption could result in increased emissions to the facility, rendering the measures inconsistent with §112(d)(2). Alternatively, undertaking measures to reduce fuel consumption could require more costly measures to counterbalance the effect of the reduced fuel consumption, rendering the measures not cost-effective. What is clear, however, is that EPA cannot possibly project with any accuracy the ability of sources in this category to cost-effectively undertake energy efficiency measures, much less their emission impacts, cost, or other factors that the CAA requires be included in that analysis. The complete absence of data makes any such presumptions irrational.

EPA makes an unsupported assertion that "the costs of any energy conservation improvement will be offset by the cost savings in lower fuel costs." 75 FR at 32,026. EPA to some extent assures that this assumption will be true by defining a "cost-effective energy conservation measure" as one that has a payback period of two years or less. Id. Yet this is an artificial criterion applied with no basis or support to EPA's conclusion that the benefits of the program outweigh the costs. There is not in the record any substantiation of this point. Project justification criteria vary significantly by company, facility, product and even time of year. EPA's conclusory analysis of the cost-benefit analysis vastly oversimplifies capital expenditure decisions and artificially limits the calculus to fit the need to justify the beyond-the-floor standard. Nowhere, however, does EPA explain what provision in §112(d) or elsewhere in the CAA grants EPA the authority to mandate investment criteria for projects implemented pursuant to the energy assessments.

Even regarding the presumption of emission reductions itself, the proposal is very inconsistent. In some sections, the proposal accurately points out that if efficiency measures are implemented, fuel use is reduced, HAP emissions may be reduced and energy-related savings realized. 75 FR. at 32026. Yet, in other sections, the proposal inaccurately asserts that the energy assessment in-and-of-itself will lead to emission reductions. 75 FR 32026.

D. EPA Lacks Authority Under the Clean Air Act to Compel Regulated Facilities to Implement Any Measures That May Be Identified in an Energy Assessment.

EPA is considering whether to require the implementation of energy saving measures and seeks comment on whether that would be "economically feasible." 75 FR 32,026. EPA needn't determine the economic feasibility of their implementation, because in any event, EPA has no authority to compel sources to implement the findings.

No provision of the CAA provides EPA with the free-ranging authority to compel energy efficiency reductions at a regulated source. It is quite possible that an energy efficiency measure, if implemented, would constitute a "modification" that would trigger other provisions of the Clean Air Act such as PSD or new-source status under NSPS. This is probably likely, given that the assessment is intended to identify "major" energy conservation measures. 75 FR 32014. If indeed major measures are identified, then a fortiori EPA lacks authority to compel their implementation, where that would effectively require additional permitting measures unrelated to the MACT implementation. EPA likewise lacks authority to compel reduced fuel use to reduce HAP emissions from the boiler, where that would cause increased HAP or non-HAP emissions from systems affiliated with or served by the regulated boiler. In instances where energy consumption adjustments could cause adverse consequences at the source, such as, for example, exceeding allowable emission limits or consuming an unacceptable amount of the compliance margin for a particular pollutant, EPA lacks the authority to compel a source to undertake such measures.

E. If EPA Decides to Require an Energy Assessment, Several Features Should Be Amended; Cost and Other Beyond-the-Floor Impacts Should Be Analyzed, Which Will Require Notice and Comment.

1. The assessment should be expressly limited to HAP reductions at the affected source, consistent with § 112.

2. EPA must also consider impacts of the assessment, including cost and whether boiler-related HAP reductions may be offset by HAP and other pollutant increases, or other energy-consumptive measures that could occur at the facility associated with the boiler.

For any beyond-the-floor requirement, the CAA requires EPA to analyze cost, non-air quality health and environmental impacts and energy requirements. § 112(d)(2). EPA purports to propose as beyond-the-floor that an energy assessment be undertaken, yet it relies on projected energy and cost benefits from implementation of the assessment. The record lacks any beyond-the-floor analysis of requiring either the assessment or its implementation, without which EPA has no basis to sustain the requirement.

EPA estimates the cost of an energy assessment to be $2500 - $55,000, depending on the size of the facility. EPA also notes that 1551 facilities would be required to perform the assessment at an annualized cost of $26 million. Based on experience with energy assessments, we estimate the cost of an energy assessment at a complex facility with multiple types of combustion equipment and systems could well exceed $100,000 since multiple types of people would be needed. At one Eastman facility, ~ $1M was spent to employ a consultant to identify energy efficiency opportunities for ~ 75% of the plant site over a one year period. The $1M reflects only the external cost of the consultant. It does not account for the very significant time required of staff engineers and area managers to meet with the consultant or the pre-work required mostly of the energy engineering staff. The need to evaluate economic viability of changes requires engineering and cost estimates of capital expenditures and determination of return on investment or economic payback; the level of engineering assessment typically requires some level of design, thus greatly increasing the cost of the assessments and project viability determination. The EPA estimated cost in no way would cover such a level of detail. Programs developed by DOE have not extended fully throughout facilities or to the level of detail envisioned by EPA, so that comparable costs to DOE programs are not necessarily correct. Therefore, the total cost and burden of the energy assessment requirement as proposed will be significantly higher than estimated by EPA.

3. Adoption of ENERGY STAR should not be required to replace the far more sophisticated, source-specific energy management programs already in place at regulated sources.

In many cases facilities and companies have already conducted detailed energy assessments. If any energy assessment requirement is included in the final rule, regulated entities should be allowed to utilize any existing programs or assessments to the extent possible.

4. The assessment should be done by facility or company staff rather than by contractors.

The proposal would require sources to hire a "qualified specialist" "who has successfully completed the Department of Energy's Qualified Specialist Program for all systems or a professional engineer certified as a Certified Energy Manager by the Association of Energy Engineers." 75 FR 32026. This is an arbitrary requirement that overlooks existing regulated entity resources. Sources have at their disposal the most qualified individuals to assess the energy savings opportunities for the regulated source – those who are most familiar with the processes involved, day-to-day operations, and historic patterns of operation at the site. Sources should not be compelled to contract with outside personnel who are far less knowledgeable about the operations of the site, to assess energy conservation measures that may be undertaken. This requirement would unnecessarily increase costs and burden to the regulated entities.

F. The Energy Assessment Will Require Sources to Submit Data That in Many Cases Constitutes Confidential Business Information.

A requirement that an energy assessment be conducted for energy systems served by all combustion units that are affected sources would require evaluation of confidential processes and systems. Since these evaluations and resulting information do not reflect the control of HAP emissions, EPA has no authority to require that sources provide this information. Even if EPA were to expressly indicate that such data provided does not constitute emissions data, and may therefore be protected from dissemination as confidential business information, this approach still does not resolve EPA's lack of authority to compel its submission in the first instance. In addition, CBI protections are not absolutely protective of sensitive data, as they are discretionary and always subject to evaluation and reevaluation by EPA.

Although current CAA CBI regulations permit a source to designate information provided to EPA as CBI, the type of information EPA proposes to compel companies to report here is, by legal definition, CBI. 40 C.F.R. § 2.301(e) (allowing information to be designated as trade secret, proprietary or company confidential). Therefore, EPA should not permit competitors to force reporting entities to defend the nature of this data in an agency CBI proceeding. Whether such information constitutes CBI should not be assessed on a case-by-case basis. Instead, it should be given categorical protection because the entire class of information EPA is seeking here constitutes CBI, it is not emissions data and its collection is outside EPA's § 112 authority.

G. EPA Should Provide a Clear, Statutory-Based Definition Of "Boiler"

If EPA includes an energy assessment requirement in the final rule, it should regulate only the emission source over which it has §112 authority to regulate. Under §112, EPA has authority to establish emission limits for the emitting boiler or process heater. The "boiler" logically includes the combustion unit (the emissions source) and closely associated equipment, from flame to last heat recovery.

EPA proposes to impose a beyond the floor energy assessment on the "boiler system," defined as:

> the boiler and associated components, such as, the feedwater system, the combustion air system, the fuel system (including burners), blowdown system, combustion control system, and energy consuming systems.

75 FR 32063.

Instead, EPA should adopt this definition of "boiler system," which that reflects the extent of its §112 authority:

> the boiler and directly associated fuel components, combustion air components, and flue gas heat recovery components.

XXX. Start-up, Shut-down, Malfunction

EPA is proposing that the emissions standards it has established in this rule apply during both normal operations and periods of startup, shutdown and malfunction (SSM). CIBO strongly disagrees with this approach, believing it is inappropriate to require compliance with emissions standards that are achievable during periods of steady-state operation during periods of startup and shutdown. CIBO also believes that affected sources may be unable to comply with the standards during SSM periods, and therefore the proposed standards are contrary to the CAA's requirement that standards established under Section 112(d) be "achievable." *See* 42 U.S.C. § 7412(d)(2). According to the D.C. Circuit, this when "achievable" means "under the most adverse conditions which can reasonably be expected to recur." *National Lime Ass'n v. EPA*, 627 F.2d 416 (D.C. Cir. 1980). If sources cannot meet the proposed emissions standards during "routine" periods of startup and shutdown, nor during adverse periods of malfunction, the proposed standards are therefore not "achievable," and thus not compliant with the Act.

A. EPA Asserts without Support that CEMs Data includes SSM Periods.

To support its conclusion that the proposed emission standards are achievable during all operational periods, including during SSM events, EPA asserts that startup and shutdown emissions replicate normal operation emissions. These conclusions are not supported by the record. EPA relied on continuous emission monitoring (CEMs) data obtained from best performing units, which EPA claims included periods of startup and shutdown. It is unclear to CIBO whether this CEMs data actually warrants these conclusions. First, it does not appear that any of the units considered in the data collection were in startup or shutdown during the 30-day period of testing that EPA looked at. If that is the case, then the CEMs data gives no bearing on whether units can satisfy emissions limits over a 30-day period if all startup and shutdown events are included.

Additionally, EPA is operating on the assumption that "[b]oilers, especially solid fuel fired boilers, do not normally start up and shutdown more than once per day[,]" and that "startup and shutdown are part of [boilers'] routine operations and, therefore, are already addressed by the standards." 75 FR at 32,012. These are not accurate conclusions for many boilers, as circumstances may necessitate multiple startups and shutdowns throughout a day, and additionally, that a boiler may routinely need to start up and shut down does not mean the emissions from those events are the same as the emissions during steady-state operation. Further, the CAA has been interpreted to require that emissions standards be achievable under the most adverse conditions that can be expected to occur, not under assumptions of what is *normally* done or not done. EPA has not show that it actually considered startup and shutdown periods even though it is proposing to implement emissions standards that should apply to units during steady-state operations as well as such periods.

Another concern that CIBO has is that EPA used 3-run stack test data, and not 30-day data, to set the proposed emissions floors. EPA uses test run data collected through the ICR phase II testing process – which reflect normal, often steady state, operating conditions – to set proposed floors. Even EPA's docket materials in support of the Proposed Rule acknowledge that this data fails to account for the dynamic conditions and variable emissions occurring during startup and shutdown episodes. Further, this data does not make use of the CEMs data (with the startup and shutdown information) in its variability analysis, which is where it would be the most helpful in reflecting real-world fluctuations in emissions.

B. Requiring Emissions Controls during SSM is Not Technically Feasible.

The current decision by EPA to 'eliminate' omission of startup, shutdown, and malfunction emissions records is not only 'short sighted' but technically unjustified. A series of previous emission control programs over the last twenty-five years has resulted in the installation of several 'systems' to achieve specific emission reductions through targeted technologies, but most are designed for 'steady state' or 'normal operations'.

The first of these was implemented under the CAA revision of 1990 that required units larger than 25 MWe to reduce sulfur emissions below 1.2 lb/MMBtu and achieve at least a 90% reduction. One of the few methods of doing this that could survive severe abrasive characteristics present in some units was dry limestone injection. This process is dependent on injection of 'sized' limestone into the furnace/boiler, calcinations of the limestone, and subsequent absorption of sulfur present in the flue gas. This process 'begins to occur' at a useful rate at about 860 deg. F and is 'functional' up to about 2200 deg. F. (Unfortunately at about 1640 deg. F thermal NOx generation normally inhibits operation above that temperature.) For a boiler to achieve the lower useful temperature of 860 deg. F, it must be 'heated up' to that level, generally using natural gas or fuel oil. This 'thermal change' to the materials that boilers are fabricated with, is limited by impacts of thermal stresses placed on both the generating tubes and drum materials, by the manufacturers to a change rate of 100 deg. F. Thus, to take a unit from 'cold' to the functional temperature that limestone becomes effective for SO2 removal, takes a minimum of about eight to ten hours. Application of 'normal steady state' limits based on a temperature of 1600 deg. makes no sense. Due to the high volume of combustion air involved, most 'casualties result in the unit falling outside of the optimum band for absorption also, so application of the limits during these periods is short sighted, as it is technically unfeasible to attain them.

A similar situation exists with respect to NOx. Many facilities were 'swept' into further NOx reduction under the 'NOx Budget Program' in the late 1990's. To meet these requirements, most installed a Selective Non-Catalytic Removal system, which injects ammonia or urea into the combustion gas stream and results in much of the NOx present there becoming a 'solid' and mixing into the ash residue from combustion. This process occurs at a meaningful level at temperatures above 1200 deg. F up to about 1650 deg. F. The same 'heat-up' limits apply for cold plant startup, as well as casualty impact as listed above.

A second '1990' requirement resulted in baghouse installation instead of electrostatic precipitators for any new installations. Unfortunately, for many of these units the baghouses were unable to withstand the 'gas stream temperature' when they were heated up to operating temperature with gas or fuel oil burners, as the 'bags' in them were limited to temperatures less than 350 deg. F. but greater than 150 deg. to avoid water formation/plugs in the ash and air stream. The high end could not be maintained with limited combustion air heater flow until the units temperature approached about 800 deg. F during the heat up, while the lower end was present until achieving at least 300 deg. during the heat up. A 'baghouse' bypass was installed for that purpose, although not used at any other time. Currently 'some' bag vendors have developed replacements that can withstand a higher temperature and are more resistant to casualty situations, but not all of them.

All of the above are functional in reverse during a shutdown. Other types of 'emissions removal' (e.g., SCR) also require specific 'thermal inlet' temperatures to function that cannot be maintained during either startup, shutdown, or during specific malfunctions.

Lastly, many CEM units are 'calibrated' to operate at specific stack temperatures associated with 'normal operations'. During 'thermal cycles' of the unit, it is doubtful that any of the CEMs maintain required accuracy much less record actual 'emissions.' It is likely that the only trustworthy data is opacity during SSM as most of the other instruments may provide an output, but nothing in the current regimen of testing assures its accuracy.

EPA has long recognized that control and/or monitoring equipment is not necessarily functional during SSM periods. In developing the SSM approach in the General Provisions, EPA recognized the "difficulty of determining compliance" during SSM periods. 58 FR 42,777 (Aug. 11, 1993). EPA adopted an approach whereby an owner of an affected facility who abides by a valid SSM plan during SSM periods would not be deemed in violation of the applicable standard. EPA stated:

> This approach carries forward the requirement that control systems be operated at all times, but it allows special situations to occur, such as unpredicted and reasonably unavoidable failures of air pollution control systems, when it is technically impossible to properly operate these systems. 58 FR 42,777 (Aug. 11, 1993).

In the preamble to the final General Provisions, EPA responded to one commenter who said EPA should require affected sources to meet otherwise applicable emission limits during startups, shutdowns, and malfunctions. EPA said it "believes, as it did at proposal, that the requirement for a startup, shutdown, and malfunction plan is a reasonable bridge between the difficulty associated with determining compliance with an emission standard during these events and a blanket exemption from emission limits." 59 FR 12,423 (Mar. 16, 1994). We believe EPA's rationale applies to affected sources subject to the Boiler MACT standards and we fully support retaining this approach to startup, shutdown and malfunction in the final regulations.

C. An Extended Averaging Period Will Not Eliminate Problems With Making Emissions Limits Applicable During Startup and Shutdown Periods.

Institutional, commercial and industrial boilers, require an extended period of startup lasting several hours (e.g. gas, liquid, or solid fuel boilers) or days (e.g. large circulating fluidized bed boilers). During the required startup periods, most, if not all, equipment in the boiler and pollution control systems are not operating in their normal condition. Consequently, pollutant emission concentrations and emission rates can exceed those experienced during normal operation. It is very common in the boiler industry for certain control devices to be out of operation during periods of startup due to the nature of the equipment. During such periods it is likely that emissions will exceed the standards proposed and would never be able to recover to meet the average limitations. (See below for a more expanded discussion with respect to a few specific technologies). This extended startup period, ranging from several hours to a few days for some specific units, is required due to equipment integrity concerns, limitations of the technologies, or safety concerns:

> Equipment Integrity – For example, a Fabric Filter (FF) cannot be put into service until the flue gas temperature is above the dewpoint. This requires that all heat transfer surfaces, ducts and flues from the combustion zone to the FF inlet be warmed up from ambient temperatures to dewpoint temperature (which varies by fuel type and fuel constituents, but is typically in excess of 140°F /60°C). It takes a considerable amount of time, typically several hours for larger units, to warm up this considerable mass of steel: waterwall tubes, superheater tubes, reheater tubes, economizer tubes, casings, turning vanes, air preheaters, ducts and inlet plenums. During this warmup period, the FF cannot be put into service without risking catastrophic failure of the bags and intensive corrosion damage to the FF. This limits a unit's ability to control Particulate Matter and Mercury during the several hours of startup.
>
> Limitations of the Technology – For example, units equipped with a Spray Dryer Absorber (SDA) for acid gas removal are limited in the amount of reagent slurry that can be injected into the flue gas during startup. The slurry federate is limited due to the nature of the technology by the amount of moisture the flue gas can evaporate. This in turn requires that a minimum temperature be achieved by the flue gas before the slurry federate can be initiated, and imposes a lengthy period of time during which the slurry federate is significantly limited until all the upstream heat transfer surface and ductwork has been warmed up. As such, SDA cannot remove Hydrogen Chloride in significant quantities for several hours after the unit is first fired.
>
> Safety Concerns – For example, reductions in the amount of time required to warm the boiler system up could be realized by increasing the ramp-rate of adding fuel to the unit. In theory, a boiler could be brought from first flame to full load in a matter of minutes, but decreasing the warm-up period from what the OEM recommends risks severe metallurgical stresses due to rapid changes in temperature and wide variances in temperatures across boiler and duct parts. Immediate failures could occur if inconsistent heating caused tears or ruptures in support steel or heat transfer surfaces, posing considerable risk to personnel in the plant. Failure rates would also increase due to the considerable stresses introduced by rapid heating and cooling cycles, yielding failures at unpredictable times (steady state operation or future startups or shutdowns). For this reason, OEM recommendations for startup times are closely followed across industry.

EPA makes a mistaken assumption that startups and shutdowns are "predictable and routine." 75 FR at 32,012. Industrial facilities, unlike electric utilities, typically operate a large number of smaller units of varying ages instead of operating a small number of very large units. When normal equipment failure rates (e.g., tube leaks) are multiplied across a large number of units, the total number of unit failures can be significantly larger at industrial facilities. One member company operates a facility with over a dozen boilers, which average more than two unplanned outages per unit above and beyond each unit's planned outage in a any given year. It is not uncommon for unplanned outages to occur in clusters, such as when a given component (e.g., an economizer) might suffer a failure due to corrosion or erosion. Repairs may fix the failure at identified vulnerable areas nearby, but the root cause of the failure could be occurring in multiple areas that are not easily identified, resulting in additional failures in a short timeframe.

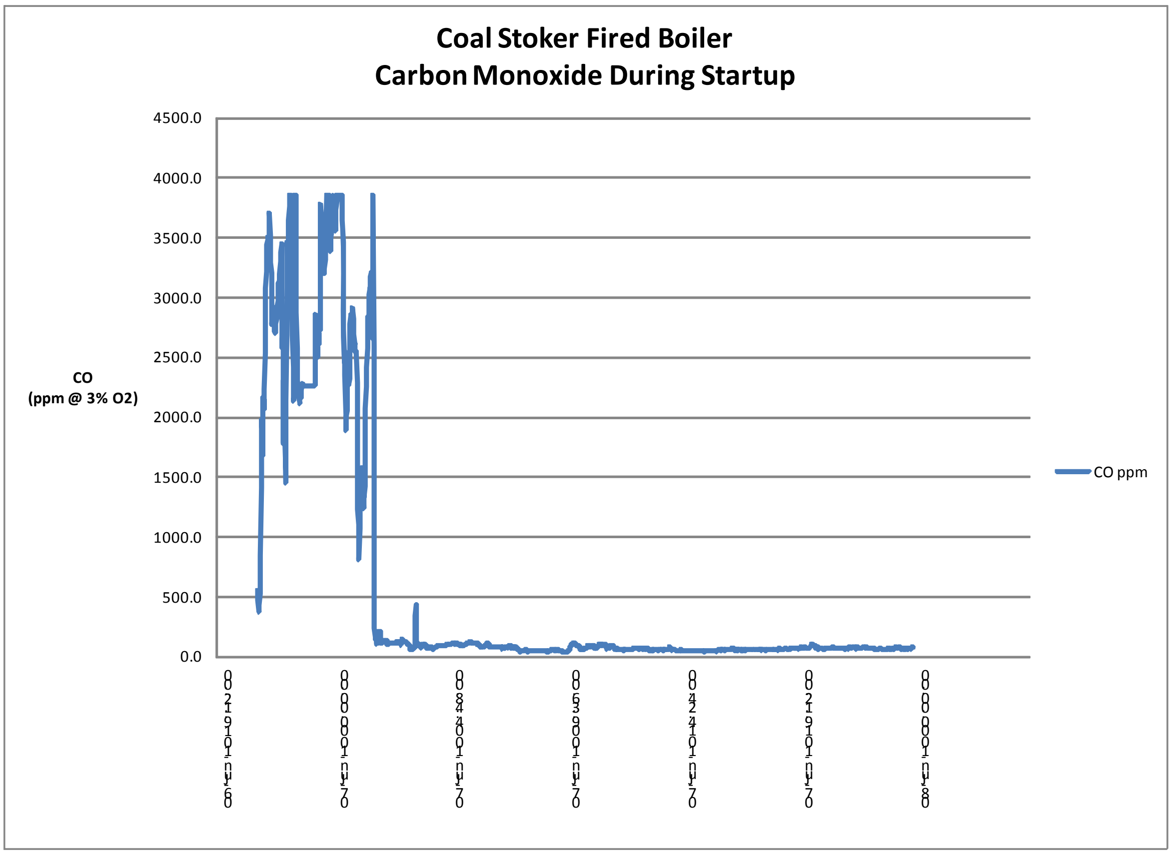
EPA seeks to address the fact that units will not be able to comply with the proposed emissions standards by during startups and shutdowns by proposing extended (daily or monthly) averaging periods. The assumption that longer averaging periods will provide a reasonable method to ensure compliance is likewise flawed. Startup and shutdown periods vary in duration and intensity, a fact that can significantly impact actual emission profiles. Additionally, because unplanned outages are a reality in the operation of any boiler, industrial or utility, and because unplanned outages are by their nature unpredictable, unplanned shutdowns can and will cluster together. For example as shown by the table below, if a unit firing eastern bituminous coal equipped with a Spray Dryer Absorber for acid gas control were to have two unplanned outages in the month following startup from a planned shutdown, the calculation of a 30-day average fails to prevent a deviation from the HCl standard:

	Eastern Bituminous Coal		
	Chlorine, ppm	1,000	
	Coal HHV, Btu/lb	12,500	
Day	24h HCl Emission	30d Avg	Notes
1	0.080		Uncontrolled, due to startup from planned shutdown
2	0.018		
3	0.018		
4	0.018		
5	0.018		
6	0.018		
7	0.018		
8	0.018		
9	0.018		
10	0.080		Uncontrolled, due to startup from unplanned outage
11	0.018		
12	0.018		
13	0.018		
14	0.018		
15	0.018		
16	0.018		
17	0.018		
18	0.018		
19	0.018		
20	0.080		Uncontrolled, due to startup from unplanned outage
21	0.018		
22	0.018		
23	0.018		
24	0.018		
25	0.018		
26	0.018		
27	0.018		
28	0.018		
29	0.018		
30	0.018	0.024	30d average > Emission Standard

30 Day Average Calculation of HCl for a Boiler Equipped with a Spray Dryer Absorber

Such a scenario would result in a unit being out of compliance because EPA inappropriately failed to craft a compliance protocol to address the fact that emissions performance during startups and shutdowns is necessarily not equivalent to emissions performance during steady-state operation.

Extended averaging periods are similarly inadequate to provide a reasonable method to demonstrate compliance with the CO standard, due to the inherent variability of CO in solid fuel boilers across the load range, but especially upon startup. See the figure below showing CO data from a coal stoker fired boiler that monitors CO via CEMS. It is readily apparent that CO emissions during normal startup conditions can be two orders of magnitude above the proposed standard of 50 ppm for stoker boilers.



Carbon Monoxide During Startup of a Coal Fired Stoker Boiler

This table demonstrates the impact of the startup of this unit on the calculation of a 30-day average:

Date	CO Daily Avg ppm @ 3% O2	CO 30d Avg ppm @ 3% O2	Below Proposed MACT Standard for Stoker Blrs? (< 50 ppm @ 3% O2)
6/6/2010	3519.2		
6/7/2010	330.5		
6/8/2010	56.7		
6/9/2010	60.7		
6/10/2010	60.4		
6/11/2010	60.3		
6/12/2010	61.0		
6/13/2010	55.7		
6/14/2010	50.0		
6/15/2010	45.9		
6/16/2010	44.5		
6/17/2010	43.6		
6/18/2010	40.8		
6/19/2010	39.9		
6/20/2010	39.5		
6/21/2010	44.0		
6/22/2010	48.3		
6/23/2010	45.0		
6/24/2010	48.4		
6/25/2010	45.3		
6/26/2010	49.4		
6/27/2010	53.4		
6/28/2010	53.3		
6/29/2010	48.9		
6/30/2010	49.3		
7/1/2010	49.7		
7/2/2010	46.2		
7/3/2010	37.4		
7/4/2010	43.3		
7/5/2010	**50.6**	**174.0**	**NO**
7/6/2010	**47.6**	**58.3**	**NO**
7/7/2010	47.0	48.9	YES
7/8/2010	52.2	48.7	YES
7/9/2010	44.8	48.2	YES
7/10/2010	42.9	47.6	YES
7/11/2010	40.1	46.9	YES
7/12/2010	38.1	46.2	YES
7/13/2010	36.2	45.5	YES
7/14/2010	39.2	45.2	YES
7/15/2010	45.1	45.1	YES
7/16/2010	50.2	45.3	YES
7/17/2010	40.8	45.2	YES

30 Day Average Calculation for the Coal Fired Stoker Boiler Startup

This data set illustrates the impact of a typical unit startup on a calculated 30 day average and the problem with requiring a unit to comply with a steady-state emission standard during startups and shutdowns. Had this unit been subject to the standard proposed in this rule, the source would have been out of compliance due to the two calendar days that saw startup activities, despite the fact that the source was operated near or below the proposed standard for CO the following 40 days.

Instead of relying on extended averaging periods, EPA should instead provide additional provisions to ensure emissions are minimized during startups and shutdowns without unreasonably requiring sources to attempt to comply with steady-state emission standards. EPA should add provisions to require sources to develop and adhere to operating practices specific to the unit's design, fuel type, and OEM recommendations that will ensure emissions minimization without forcing owner/operators to choose between putting their equipment integrity and personnel safety at risk versus failing to comply with this rule. Such an operating practice should be crafted to be flexible, given the wide variety of boiler sizes, types, vintages, and fuels fired, and should be developed by the source based on OEM recommendations. General guidelines could include:

- Sequencing of equipment startups, per OEM recommendations;
- Startup time durations, per OEM recommendations, and
- Provisions to clearly define what constitutes "online" versus "startup". This could be crafted to mean a percentage of the unit's maximum continuous rating, or steam temperature/pressure, etc.

CIBO notes that EPA followed this approach in its final rule for Reciprocating Internal Combustion Engines (RICE) issued on March 3, 2010. There, EPA concluded "it was not feasible to prescribe a numerical emission standard for stationary CI engines during periods of startup because the application of measurement methodology to these engines is not practicable due to the technological and economic limitations described below." 75 FR 9665. Many of the reasons EPA articulates for this decision apply to the boiler and process heater source category regarding the accuracy of the stack gas sampling methods during transient load cases like startup. Eastman recognizes that EPA has set work practice standards in the RICE rule by limiting startups to 30 minutes. We agree this is appropriate. However, when it comes to boilers and process heaters, it is a much more complicated issue. Given the variety of units, operating pressures and temperatures, etc., we do not believe it is practical to set startup and shutdown periods on a "one-size fits all" basis. Rather, each source should work with their permitting authority to establish and obtain approval of appropriate work practice standards as we discuss above.

CIBO proposes two solutions to fix the deficiencies in the Proposed Rule relative to startup/shutdown emissions expectations. First, CIBO proposes that EPA should use operating practices during startup and shutdown to include general content relative to specific startup and shutdown sequences and time limits pending meeting emissions limits. Alternatively, if EPA uses a startup/shutdown standard, EPA should establish an averaging period that accounts for a wide range of emissions from startup and shutdown.

D. Malfunction Periods Not Account for in Floor Setting.

The Proposed Rule also expects that the emissions standards applicable during normal operations must also be met during periods of malfunction. This expectation directly conflicts with the statutory requirement that EPA set MACT standards that are "achievable" since even the best performers will experience malfunctions that may result in those sources not meeting the proposed standards. CIBO is also concerned that compliance with the emissions standards during malfunction events will be difficult to gauge since emissions testing during such events is near impossible given the sporadic and unpredictable nature of malfunctions.

Another concern is that the Proposed Rule could force units to choose between safety and compliance with emissions requirements. For some affected units, malfunctions by their very nature create unsafe conditions which can lead to excessive combustible mixtures in a furnace that can result in explosions, equipment damage and personnel hazards.

CIBO proposes that EPA set work practice requirements based on maintenance plans established by each source. Such plans should be expected to address how to expeditiously deal with malfunctions in a way that balances the desire to most efficiently minimize emissions while also maximizing safety responses and expeditiously resolving malfunction events. While the *Sierra Club* court ruled that sources cannot be exempt from complying with MACT standards, the court noted that Congress recognized in some instances that it may not be feasible to prescribe or enforce an emission standard under Section 112. *See Sierra Club v. EPA*, 551 F.3d at 1028. In such limited circumstances, section 112(h) "work practices" or "operational" standards are available. *Id*.

Section 112(h) allows the Administrator to promulgate a design, equipment, work practice, or operational standard, or combination thereof, in lieu of an emission standard where it is not feasible to prescribe or enforce an emission standard. 42 U.S.C. § 7412(h). Infeasibility exists where "a hazardous air pollutant or pollutants cannot be emitted through a conveyance designed and constructed to emit or capture such pollutant,' or "the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations." *Id*. Because of the difficulty of obtaining emissions data during malfunction periods, and the substantial variety of circumstances that may manifest during malfunction events, it would be difficult and impractical and infeasible for EPA to craft emissions standards for application during both malfunction periods and normal operations. Thus, CIBO believes that the best approach is not to continue with the present proposal of applying the same standards EPA has set for normal operations to malfunction events, but rather, for EPA to use § 112(h) to set work practice standards that would allow facilities to establish source-appropriate procedures during malfunctions. Such procedures would enable sources to maintain safe practices while addressing the malfunction and implementing procedures to minimize emissions during any such event.

E. Malfunctions Cannot Be Avoided, Even By Top Performers and EPA Should Therefore Include the Use of Malfunction Plans.

EPA states in the Proposed Rule that if a source fails to comply with the applicable standard due to a malfunction, EPA "would determine an appropriate response." 75 FR 32013. Many large sources have been required to submit "Standard Operation and Casualty Procedures" under Title V concerning time limitations of malfunctions that impact emissions. These procedures were based on not exceeding monthly averages in the permit. Furthermore, the definition for "malfunctions" appears to be inappropriate considering that many malfunctions occur due to component failure and have nothing to do with "poor maintenance or careless operation" as defined in 40 C.F.R. § 63.2. Congress acknowledged that malfunctions cannot be prevented, and provisions allow for such occurrences. [CITE] EPA also acknowledges that malfunctions cannot be prevented, even by top performers, and therefore defines the regulations at 40 C.F.R. at § 60.2. EPA unreasonably proposes all sources to comply with standards established for steady-state operation during periods of malfunction. This approach inappropriately fails to include provisions that take into account the unpredictable nature of malfunctions, and that malfunctions occur to all units including top performers.

EPA should include additional provisions to accommodate the unpredictable and unavoidable malfunctions that both Congress and EPA acknowledged would occur. EPA should adopt a work practice of requiring malfunction plans to address potential equipment failures, provide troubleshooting and corrective actions, and other reasonable measures so to minimize the duration of malfunctions and minimize emissions during unavoidable malfunctions. Using the plan and documenting actions in accordance with the plan would then constitute minimizing emissions via the general duty clause.

F. In Setting the Floor, EPA Must Account For Load Variability, Which Is Not the Same As SSM.

For combustion based emissions, such as CO, formaldehyde, dioxin/furan, and total hydrocarbons, the formation of emissions are dependent on the design of the combustion unit; the MACT floor emission limits for CO and dioxin/furan are subcategorized according to combustor design for boilers burning solid fuels. However, the emissions can fluctuate with changes in the operating rate of a boiler, or "boiler load". Boiler load was divided into two subcategories, depending on the role of a boiler at a facility. A boiler providing a relatively constant amount of steam to a facility is considered a "base-loaded" unit, and a boiler that adjusts its operating parameters to meet varying levels of demand in a plant over time is referred to a "load-following" unit.

Stack tests for CO are conducted at near full-load conditions, and although the MACT floor limits based on stack test results achieved when operating at or near full load, the MACT floor emission levels for CO might not be achieved when best performing units are operating at lower loads. For units greater than 100 MMBtu/hr, the proposal required units to demonstrate compliance with emission limits by using a CO continuous emissions monitoring system (CEMS) and calculating a 30-day rolling average. The Phase II ICR collected 30-day monitoring data on an hourly average interval for CO, and THC from six different boilers. Two boilers fired coal, two fired biomass, and two fired gas (one refinery gas and one natural gas). Each unit submitting 30-day monitoring data also reported the boiler load during each hourly average. These monitoring data were reviewed and standardized to a common basis, ppm @ 3% O2. Then, each unit's CO and THC data were plotted against the boiler load. Data corresponding to malfunction in the CO, THC, or load monitor were removed from the dataset prior to plotting. The graphs containing the CO emissions as a function of boiler load are shown in Appendix B.

Each graph was reviewed to examine the variability of CO emissions as a function of boiler load. The emissions included all periods of normal operation as well as startup and shutdown. No data associated with periods of malfunction were included in the graphs. Based on the six graphs, only the boilers firing biomass appear to show an inverse relationship between load and emissions. Additionally, the PC Boiler was plotted incorrectly and in fact does show an inverse relationship. For these two units firing biomass fuels (TXDibollTemple-Inland, PB-44; ARDomtarIndustries, PB1) there was a trend of increased CO emissions at lower boiler loads. Of these two units, only the TXDibollTemple-Inland, PB-44 unit was in the top 12 percent for CO emissions at Dutch oven boilers. The 30-day period reported by TXDibollTemple-Inland included boiler loads ranging from 17 to 77 percent of the rated design capacity of unit PB-44 and represents a boiler with large fluctuations in load. The ARDomtarIndustries, PB1 boiler is no longer in the boiler inventory, as it was identified as burning fuel cubes, a waste material under the proposed solid waste definition rule; therefore, its data was not used to assess CO variability as a function of boiler load.

A daily average was calculated for CO emissions from TXDibollTemple-Inland unit PB-44, based on the hourly averages reported for the 30-day CO and THC monitoring data. The result was 1,113 ppm @ 3% O2. This average is similar to the numerical limited calculated using 99% UPL for the dutch oven and suspension burner subcategory. Therefore, we concluded that the statistical variability correctly accounts for variability in CO emissions over various boiler loads.

Sorbent injection limits should not be fixed at the as tested/full-load injection rates as in many cases this is not considered normal boiler operation and a waste of sorbents resulting in excessive O&M costs to the boiler owner. EPA should allow an option to include both a feed forward and feed back control logics that sets injection rates based upon a feed forward operation signal such as gas flow rates or a feed back signal from certified CEMS (i.e. feed rates for mercury control are calculated based upon lb/MMacf).

Additionally, mercury emissions testing needs to include EPA Method 30a (Instrument Reference Method) and 30b- (Sorbent Trap Method), in addition to an option to include a certified continuous mercury emissions monitor (CEMS). Method 29 and Ontario Hydro are not considered accurate enough for vendors to guarantee mercury control performance at the extremely low proposed emission limit levels. These are standard tests utilized by the electric utility industry for mercury compliance measurements. *See generally* 75 FR 31938.

XXXI. Surrogates

CIBO supports the use of surrogates in the proposed Boiler MACT. EPA's use of surrogates for Non-mercury metallic HAP, Non-metallic inorganic HAP and Non-dioxin organic HAP is fully supported by long-standing case law. The D.C. Circuit has clearly held that "EPA may use a surrogate to regulate hazardous pollutants if it is reasonable to do so." *Mossville Environmental Action Now v. EPA*, 370 F.3d 1232, 1242 (D.C. Cir. 2004); *Nat'l Lime*, 233 F.3d at 634. In assessing the reasonableness of EPA's use of a surrogate in the *Nat'l Lime* case, the D.C. Circuit found that EPA satisfied this burden by demonstrating that there were always HAP metals in particulate matter (the surrogate), and thus that the removal of the particulate matter removed the HAP metals. *Nat'l Lime*, 233 F.3d at 639.

In the proposed Boiler Rule, EPA used three surrogates.

1. EPA selected PM as a surrogate for non-mercury metallic HAP due to the coincidence of PM and those metals, to reduce the cost of performance testing for every non-mercury metallic HAP and to prevent any conflict with other control technologies that may need to be adopted to comply with other MACTs. *National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters; Proposed Rule*, 75 FR 32,006, 32,018 (Jun. 4, 2010) (Boiler Rule).

2. EPA selected HCl as a surrogate for non-metallic inorganic HAP. EPA's basic rationale is that HCl is the largest component of acid gas emissions; acid gas emissions are in turn the largest proportion of non-metallic inorganic HAP, and that the best controls for HCl would also be the best controls for other inorganic HAP that are acid gases. Boiler Rule, 75 FR at 32,018.

3. EPA selected CO as a surrogate for non-dioxin organic HAP. Measures for the control of CO emissions also control non-dioxin organic HAP, therefore, standards limiting emissions of CO will result in decreases in non-dioxin organic HAP emissions. In addition, EPA believes that establishing emission limits for specific organic HAP (with the exception of dioxin and furan) would be impractical and costly. Boiler Rule, 75 FR at 32,018.

EPA's use of surrogates is well-supported by longstanding case law. Surrogates may be used for compounds regulated under section 112 where it is reasonable to do so and not otherwise contrary to law. *Nat'l Lime Ass'n v. EPA*, 233 F.3d 625, 637 (D.C. Cir. 2000); *see also Kennecott Greens Creek Mining Company v. Mine Safety and Health Administration*, 476 F.3d 946, 955 (D.C. Cr. 2007) ("there is nothing inherently problematic with an agency regulating one substance as a surrogate for another substance") (citing *Nat'l Lime*). In assessing the reasonableness of EPA's use of a surrogate, courts look to whether EPA has demonstrated a correlation between the HAP and the surrogate. *Id.*; *see also Mossville Envt'l Action Now v. EPA*, 370 F.3d 1232, 1242 (D.C. Cir. 2004) (invalidating use of vinyl chloride as surrogate where EPA failed to demonstrate correlation to HAP); *Sierra Club v. EPA*, 353 F.3d 976, 985 (D.C. Cir. 2004). While EPA's use of surrogates is supported by case law and by CIBO when appropriate, the following are comments that address outstanding issues with regard to EPA's use of surrogates in the Proposed Rule.

A. PM as a surrogate for non-mercury metallic HAP.

EPA chose PM as a surrogate for non-mercury metallic HAP because "[m]ost, if not all, non-mercury metallic HAP emitted from combustion sources will appear on the flue gas fly-ash. Therefore, the same control techniques that would be used to control the fly-ash PM will control non-mercury metallic HAP." *Id.* In addition, EPA recognizes that using PM as a surrogate will eliminate costly performance testing to comply with multiple individual standards. *Id.* These reasons are sufficient to sustain use of PM as a surrogate for non-mercury metallic HAP.). In *National Lime*, the D.C. Circuit held that as long as EPA demonstrates that there is a correlation between the HAP controlled (in that case, metals) and the surrogate (in that case, PM), "it need not quantify that correlation or assess its variability because PM control technology is such that each unit of PM emissions avoided 'carries' within it some quantum of HAP metals." *Nat'l Lime Ass'n*, 233 F.3d at 639. Furthermore, EPA acknowledges that most sources generally emit PM that includes some amount and combination of metallic HAP. *See Bluewater Network v. EPA*, 370 F.3d 1, 18 (D.C. Cir. 2004) (upholding EPA's use of hydrocarbons as a surrogate for PM because, in part, HC contributes to PM pollution). As the D.C. Circuit has recognized, "[i]f HAP metals are invariably present in [source] PM, then even if the ratio of metals to PM is small and variable, or simply unknown, PM is a reasonable surrogate for the metals," assuming that PM control technology indiscriminately captures HAP metals, which is true here, and that there is no independent method of controlling the HAP which did not control for PM as well, which is also true here. *Id.*; *see also Sierra Club v. EPA*, 353 F.3d 976, 985 (D.C. Cir. 2004) (applying *Nat'l Lime*'s "three-part analysis" of invariable presence, indiscriminate capture and sole method of control to uphold use of PM as a surrogate for HAP).

EPA's decision to use PM (filterable) rather than $PM_{2.5}$ is also reasonable because sources with wet scrubbers cannot measure $PM_{2.5}$, making the surrogate more broadly applicable. In addition, the majority of the filterable PM emitted from units that are well-controlled for PM *is* $PM_{2.5}$. See 75 FR 32018. This conclusion is supported by emission data obtained from units not equipped with wet scrubbers during EPA's information collection effort, and so EPA's use of PM (filterable) is reasonable.

B. HCl as a surrogate for non-metallic inorganic HAP.

EPA chose HCl as a surrogate for non-metallic inorganic HAP because "the emissions test information available to EPA indicate that the primary non-metallic inorganic HAP emitted from boilers and process heaters are acid gases, with HCl present in the largest amounts." 75 FR 32018. EPA found that other inorganic compounds emitted are found in much smaller quantities than HCl. *Id.* In addition, "[c]ontrol technologies that reduce HCl also control other inorganic compounds such as chlorine and other acid gases." EPA's reasoning is thus consistent with *Nat'l Lime* and *Sierra Club* because it has demonstrated a "[s]trong direct correlation" between HCl and acid gases, in that the data demonstrates that HCl is present in acid gas emissions, usually in the largest amounts. *Sierra Club*, 353 F.3d at 985. In addition, EPA has shown that the best control technologies for HCl are also the best controls for other inorganic HAP that are acid gases. 75 FR at 32,018; *see Nat'l Lime*, 233 F.3d at 639. This is a sufficient basis for EPA to use HCl as a surrogate for non-metallic inorganic HAP. *See Bluewater Network*, 370 F.2d at 18 (EPA use of surrogate was reasonable surrogate provides a "good proxy" for regulating other emissions).

C. CO as a surrogate for non-dioxin organics.

EPA chose CO as a surrogate for non-dioxin organic HAP. As EPA recognizes, CO has generally been used as a surrogate for organic HAP because CO is a good indicator of incomplete combustion and organic HAP are products of incomplete combustion. 75 FR 32018. EPA proposes to use emission control methods, including achieving good combustion or using an oxidation catalyst, that both control CO emissions and non-dioxin organic HAP. This correlation, though one step removed from the correlation between PM and HAP metals, is sufficiently strong to support use of CO as a surrogate. EPA need not quantify the correlation or assess the variability because the control technology—good combustion or using an oxidation catalyst—will always reduce some quantum of the non-dioxin organic HAP. *Nat'l Lime*, 233 F.3d at 639. Given this correlation, EPA is permitted to use CO as a surrogate for specific organic HAP because of the impracticality and cost of establishing emission limits for specific organic HAP. *See Sierra Club*, 353 F.3d at 986 (reasonable for EPA to use a surrogate "in light of the impracticability of setting individual standards for each metal"); *Bluewater Network*, 370 F.3d at 18 (use of hydrocarbons as surrogate for PM was reasonable where "direct regulation of PM is more difficult").

EPA's rationales for the use of each of these surrogates are in accord with the facts and the law on this issue. EPA has identified the HAP that it is attempting to regulate. *Mossville Envt'l Action Now v. EPA*, 370 F.3d 1232, 1243 (D.C. Cir. 2005) (invalidating use of vinyl chloride as a surrogate where EPA did not identify the HAP for which it was serving as a surrogate). There is no legal barrier to using PM or any criteria pollutant as a surrogate for HAP in this context,. *Nat'l Lime Ass'n*, 233 F.3d at 638-39. EPA has established that these HAP invariably coexist with the surrogates and will be controlled to some extent by the same technology that controls the surrogate. *See Nat'l Lime*, 233 F.3d at 639. EPA need not make a numerical estimate of the correlation or discuss its variability. *Id.* Where alternative surrogates for or methods to control these HAP exist, EPA identified and discussed them. *Sierra Club*, 353 F.3d at 986. EPA has demonstrated the correlation between the HAP and the surrogates, clearly meeting the standard of reasonableness under *National Lime* and *Sierra Club*.

While CIBO agrees that CO is an appropriate surrogate for organic HAP, there are some issues that EPA should address. First, HAP emissions are minimized at levels well above the CO emission standard. In fact, at CO levels below 100 ppm, the differences in organic HAPs emitted are negligible. While high CO levels may imply organic HAP emissions, levels below 100 ppm likely do not have the same proportional level of HAP emissions. EPA should adjust the CO emission standard to reflect that the organic HAP concentration becomes insensitive to CO below certain levels. As discussed in other sections of these comments, forcing CO compliance increases NOx and wastes energy and it is not feasible to have an ultra low NOx burner and CO emissions of 1 ppm. EPA should incorporate a variability concept into the development of the CO standard so regulated sources can actually achieve it and also obtain the HAP reductions desired.

Furthermore, total hydrocarbons (THC) could be used as an alternative standard to CO as a surrogate for non-dioxin organic HAPs. While most hazardous waste incinerator operators will rely on the CO option, some sources may opt to select the THC option as THC CEMS, while more costly, are a workable option. THC levels are often more stable and less reactive to load swings than CO. Since THC is an indicator of non-dioxin organic HAPs (CO is not a HAP whereas much of the THCs are HAPs), there is no reason EPA cannot provide a THC option. Without the THC option, some sources are likely to be faced with a very costly choice: either install a capital intensive CO catalytic reduction system; or remove the most modern and most effective combustion controls for NOx to control CO, and install very expensive post-combustion NOx reduction technologies such as Selective Catalytic Reduction (SCR).

The use of less capital intensive NOx control technologies like Selective Non-Catalytic Reduction (SNCR) on units equipped with SDA's, due to the negative downstream effects of ammonia slip on personnel safety (NH3 release in recycle slurry) and the reliability of downstream components (formation of fouling ammonium salts). Further note that either of these options will significantly increase system draft loss, which will likely require a new ID fan at considerable expense. The enormous capital expense of these options present are not justified, given that such a solution reduces CO but may not actually reduce non-dioxin organic HAPs. This is a classic case of unintended consequences with little commensurate benefit to health or the environment.

D. Total Selected Metals as an Alternative Compliance Measure.

PM is clearly an appropriate surrogate for non-mercury metallic HAP. However, EPA should provide an alternative compliance measure for non-mercury metallic HAPs where a source burns fuel containing very little metals but sufficient PM emissions to require control under the PM provisions of the Proposed Rule. Otherwise, for those sources that burn fuel containing very little metals, EPA is simply setting a PM emission limit. In the 2004 Boiler MACT, EPA recognized that in such cases PM would not be an appropriate surrogate for metallic HAPs. *See* EPA-HQ-OAR-2002-0058-0013, *National Emission Standards for Hazardous Air Pollutants for Industrial/Commercial/Institutional Boilers and Process Heaters; Proposed Rule*, 68 FR 1,660, 1,671 (Jan. 13, 2003). EPA proposed an alternative metals emission limit set for the sum of emissions of eight selected metals: arsenic, beryllium, cadmium, chromium, lead, manganese, nickel and selenium, also known as the total selected metals or "TSM," representing "the most common and largest emitted metallic HAP from boilers and process heaters." *Id.* EPA determined that this alternative TSM surrogate was appropriate because sufficient information was not available for each metallic HAP for every fuel type, but a total metals number could be calculated for every fuel type. *See* EPA-HQ-OAR-2002-0058, *National Emission Standards for Hazardous Air Pollutants for Industrial/Commercial/Institutional Boilers and Process Heaters; Final Rule*, 69 FR 55,218, 55,231 (Sept. 13, 2004).

Some sources burn fuels that contain very low concentrations of metals but that have sufficient PM emissions to require control under the proposed PM MACT floor. Under those circumstances, PM would not serve as an appropriate surrogate. For these sources, it is not necessary to install controls to control the metallic HAP; rather, the benefit of such controls would be to control PM, which is not a HAP regulated under section 112. MACT standards, however, may only address HAPs. *See Nat'l Lime Ass'n*, 233 F.3d at 638. Section 112(d)(2) provides an express list of factors that EPA may consider in setting MACT standards – including "the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements." This list does not allow consideration of non-HAP air quality benefits, such as the co-benefits of reducing sulfur dioxide and other non-HAP emissions. Moreover, the CAA provides other mechanisms for reducing such emissions.

Allowing these sources to comply with an alternative emission limit for total selected metals (TSM) would meet EPA's objective of controlling non-mercury metallic HAP emissions without triggering unnecessary control requirements that are otherwise beyond the scope of section 112.

This is consistent with DC Circuit decisions affirming the use of surrogates in other MACTs. Where a surrogate is appropriate and defensible for some but not all sources or all pollutants in a category of pollutants, EPA has not discarded the surrogate, but instead devised parameters for its reasonable application where appropriate. For example, in this proposed rulemaking, EPA has elected to use CO for organics, but carved out one subset of organics – dioxins – to be separately controlled. Inherent in the use of a surrogate is that it will have logical limits to its appropriateness.

E. Numerical dioxins/furans (D/F) are Inappropriate.

The proposed dioxin/furan emission standards are so low and the detection limits of dioxin/furan isomers are so variable that many boilers are likely to exceed the proposed emission limits for dioxins/furans even though the tests show that all the isomers are present below the detection limits for the 17 isomers. Given that the detection limit is used to differentiate between a blank and presence of an analyte, the above outcome is unreasonable and borders on absurdity.

One of Eastman's boilers, Boiler 30 is an excellent example of the dilemma the proposed D/F standard causes. This boiler, a pulverized coal boiler with a spray dryer absorber and ESP was tested in 2009 as part of the Phase II ICR. It is a top performer for PM and HCl and has low CO emissions. Yet, it would fail the proposed D/F standard of 0.003 ng/dscm TEQ with a stack test value of 0.006. This boiler has all the characteristics of a boiler that should have low D/F emissions. There is adequate sulfur content in the coal supply (~1 percent sulfur) to inhibit the formation of D/Fs and it had low chlorine content (~200 ppm) during the stack test. While it did have a low D/F emission rate, it still would not meet the proposed standard. While this may be an artifact of data issues related to detection limits and consistent reporting of the various boilers in EPA's limited dataset, it leaves the company with the dilemma of what can possibly be done to meet the standard.

Unlike hazardous waste incinerators or municipal waste incinerators, both of which can have much higher D/F emissions than coal-fired boilers, there is no known solution to reduce D/Fs. In the case of hazardous waste incinerators, many of them simply removed waste heat boilers to eliminate most of the D/F formation. In this case, it would be arbitrary and capricious for EPA to set a standard that requires sources to reduce what is already a very low emission rate with no known or demonstrated technologies available to make the reduction. Consequently, we recommend that EPA defer any action on this standard until more is known. Alternatively, EPA should replace the proposed numerical standards for dioxins/furans with work practice standards.

XXXII. Health Based Alternative.

EPA is authorized by Section 112(d)(4) of the CAA to consider whether emissions from a regulated HAP could affect human health when it establishes MACT standards for a particular category. In doing so, EPA can consider limiting the burden on regulated sources with HAP emissions that pose little or no health hazard by implementing a Health Based Compliance Alternative (HBCA). The HBCA constitutes a real, enforceable emission standard under the law. The HBCA is not an exemption, but rather a compliance option tied to enforceable standards. Sources governed by the HBCA must achieve specific health-based emission standards set by EPA. If these standards are not met, the source must meet the "regular" Boiler MACT compliance requirements. This constitutes a strict standard for a source that chooses the HBCA route to compliance, and should in no way be viewed as an exemption from the Boiler MACT.

The CAA's multiple compliance option structure, which contemplates application of an HBCA, enables EPA to fulfill its statutory requirement to establish emission standards for the entire Industrial/Commercial/Institutional Boilers and Process Heaters category. Whether a source is governed by the HBCA or the "regular" approach, every source in the category will be subject to an emission standard as required by the statute. EPA established this system of multiple compliance options by relying upon its clear legal authority to include HBCA for threshold pollutants as an option for compliance with the Boiler MACT.

A. The Absence of a Health Based Compliance Alternative Directly Impacts CIBO Members.

CIBO members operate boilers that burn every conceivable fuel source, including the full range of available coals, wood, natural gas, biomass, coal refuse, and other fuels. These boilers vary greatly in their design, capacities, fuel requirements, air emission characteristics and air pollution control equipment. Some plants use anywhere from two to six different sources of fuel in order to ensure reliability of supply, maintain proper operation, attempt to minimize costs and maintain the viability of production facilities to remain competitive and operational in globally competitive markets.

CIBO members in the manufacturing sector face unprecedented pressure to remain competitive in the world market. Uncertainties such as inflexibility in meeting regulatory standards in the U.S. create additional pressure on companies to shift production overseas or to close down altogether. The HBCA provides CIBO members with compliance flexibility that could prove critical to a company's decision to continue operating a particular facility or to forego raising customer prices. EPA's failure to include an HBCA substantially narrows the available options to comply with the MACT standard, and places a further strain on the equipment of CIBO's members and on the consulting engineering resources that are needed to assist industry in meeting the timelines for compliance.

B. Implementation of HBCAs.

Some of the HAPs targeted by the Boiler MACT, such as hydrogen chloride (HCl), chlorine gas (Cl2), hydrogen fluoride (HF) and hydrogen cyanide (HCN) meet the requirements for classification as threshold pollutants. Therefore, if the associated incremental ambient concentrations of these threshold pollutants as a result of emissions from a regulated source are sufficiently low, they would qualify for an HBCA under Section112(d)(4).

CIBO believes that the Boiler MACT should include HBCAs that take the form of a limited number of alternative HAP emissions limits based upon facility specific emissions of HCl, Cl2, HF and HCN and modeling against references concentrations provided by EPA using a health index.

1. EPA Should Not Consider Impacts From Multiple Sources For HCl.

CIBO feels strongly that EPA should not consider other sources' emissions when considering impacts from a single source's emissions. One of the reasons EPA has given for not proposing the HBCA for HCl in the Proposed Rule is the belief that impacts from other sources at the same facility or even nearby facilities, may need to be considered. This is an incorrect belief, as

Section 112(d)(4) indicates that only the potential threshold effects from the MACT source itself be considered. Moreover, residual risk approaches have not extended beyond the single MACT source.

2. Hydrogen Cyanide Emissions are Insignificant And Should Not Factor Into an HBCA.

As discussed above, CIBO strongly believes that an HBCA needs to be established to allow units covered by the Boiler MACT to comply with the rule's requirements and timetables. However, in setting this HBCA, CIBO believes that hydrogen cyanide (HCN) should not be included, because HCN emissions make insignificant contributions to any relevant health risk.

EPA has long recognized that the chief acid gas HAPs emitted from most industrial facilities are chiefly HCl and HF. In its 2004 response to comments on the prior Boiler MACT rule, EPA stated: "We conducted an assessment of boiler emissions and determined that . . . the contributions of other HAP [aside from HCl and chlorine] . . . to the total risk were negligible." 69 FR 55218-44 (Sept. 13, 2004). Thus, at that time, EPA commented that it did not expect HCN emissions from boilers to be covered under that rule. Id.

A review of TRI 2008 data (excluding EGUs, chemical plants, and metal mining) indicates that this conclusion has not changed over the last few years, since only 0.3% of HAP gas emissions are HCN. The Proposed Rule reaches similar results. The percentages EPA has provided for HAP emissions in the Proposed Rule – which do not include HCN emissions – sum to 99%, indicating that HAP emissions are insignificant. 75 FR 32011. Because HCN emissions are insignificant in assessing health based risk, they should not factor into HBCA compliance.

XXXIII. Averaging Periods

Emission limits should reflect intra-unit variability and averaging periods that will ensure consistent compliance.

The original Boiler MACT rule included emission limits for PM/metals, mercury, and HCl for existing boilers and PM/metals, mercury, HCl, and CO for new boilers. Compliance with the PM/metals, mercury, and HCl limits was determined using a stack test (3-hour average) or fuel sampling (90th percentile of all samples collected, no averaging period specified). Compliance with the CO limit was determined using either a stack test (3-hour average) or a CEMS (30-day rolling average). When demonstrating compliance using a 3-hour stack test, the "worst case" fuel mix was required to be fired, which may vary by compound. When demonstrating compliance using fuel sampling, facilities were required to obtain at least 3 representative samples and calculate the 90th percentile fuel pollutant content. More frequent sampling better reflected the fuel variability. For compliance with the CO limit using CEMS, variability of boiler operation was acknowledged by specifying a 30-day rolling average.

The ICI boilers burn multiple types of fuels and are subject to frequent load swings. Therefore, the emissions from these boilers vary over the course of a day, depending on the fuel burned and the required steam production. EPA acknowledged during the Phase 2 ICR test program that emissions from industrial boilers are variable by requesting multi-year historical stack test data and conducting 30-day fuel and emissions monitoring studies. One way to consider a unit's variability in emissions is to set a longer averaging time for compliance with an emission limit. Additional variability data and CEMS data should be reviewed to support longer averaging times. The court reviewing the Brick MACT authorized EPA to look at intra-unit variability and EPA's work on the Hazardous Waste Combustion MACT confirmed the importance of considering variability. EPA also acknowledged that averaging times longer than 3 hours can be appropriate for compliance with the condensate collection and treatment requirements in pulp and paper MACT Subpart S.

Averaging times of longer than 3 hours are needed for industrial boilers, especially for boilers that burn multiple fuels. The facility must be able to operate the boiler in a manner that is responsive to process needs, not at full load all the time. Longer averaging periods are critical if the MACT limits apply during startup and shutdown.

The Proposed Rule is inconsistent in the averaging times specified for operating parameters. The body of the rule specifies 3-hour parameter averages while Table 8 specifies 12-hour block averages be calculated for CPMS. Where a COMS is used, a daily block average is specified. EPA should use daily block averages for CPMS as well. A 24-hour averaging period acknowledges process variability, decreases the effect of short process upsets, and captures the variable emissions and operating characteristics of a unit over an operating day.

There are factors beyond the boiler operator's control that can cause emissions to vary over a period of days and not hours. For example, the weather will impact moisture content of solid fuels, which will affect how the fuels combust over a period of days, not hours. For a biomass boiler, the fuel supply and fuel characteristics could also vary over a period of days because mills have multiple biomass fuel suppliers providing both green and dry wood. For all types of boilers, the pollutant content of the fuel will vary over a period of days, as evidenced by the range of results obtained during the 30-day fuel sampling required by EPA for many ICR Phase 2 participants. Where CEMS are the compliance method (e.g., PM and CO), we support a 30-day averaging period to account for operational and emissions variability.

XXXIV. Emissions Averaging

CIBO supports inclusion of the emission averaging provisions in the Proposed Rule, but revisions are needed to expand and improve the usefulness of these provisions. 75 FR 32034. Use of emissions averaging would allow owners and operators of an affected source to demonstrate that the source complies with the proposed emission limits by averaging the emission from an individual affected unit that is emitting above the proposed emission limits with other affected units at the same facility that are emitting below the proposed emission limits. 75 FR 32034. EPA further acknowledges that "emissions averaging represents an equivalent, more flexible and less costly alternative to controlling certain emission points to MACT levels" and its application "would not lessen the stringency of the MACT floor limits and would provide flexibility in compliance, cost and energy savings to owners and operators." 75 FR 32034.

EPA has proposed that owners and operators of existing – but not new – affected sources be permitted to demonstrate compliance with the proposed emissions limitations by emissions averaging for units at the affected source that are within a single subcategory. 75 FR 32034.

Under this proposal, emissions averaging could only be used between boilers and process heaters in the same subcategory at a particular affected source. 75 FR 32034.

A. The rule should allow for averaging across all subcategories/fuels with emission limits for the pollutant to be averaged.

The proposed emission averaging is explained as allowing averaging only within a subcategory (75 FR 32024) although it is not clear from the Proposed Rule language if this is what EPA intended. S*ee* § 63.7522(a), 75 FR 32053. While the wording under the separate stack requirements does seem to have this restriction, the wording under the common stack requirements does not. *See* Equation 6, 75 FR 32,055. EPA provides no justification for restricting averaging to a given subcategory nor is it rational to impose such a restriction.

EPA states in the preamble that one of its limits on the scope of emissions averaging is to not allow averaging between sources that are not part of the same affected source. 75 FR 32034. In this case, EPA has elected to define the affected source in §63.7490(a)(1) as all units within a subcategory. We see no reason for EPA to use this definition. Rather all units at a given facility subject to the subpart should be collectively considered the "affected source". This is how EPA has defined the term in other rules with which we are familiar (e.g. the HON in Subpart F, Polymer and Resins 4 in Subpart JJJ, the MON in Subpart FFFF). The HON in particular we understand is the model EPA is using to guide its policy. By defining the term affected source as all chemical manufacturing process units (CMPUs) at a facility, the HON allows emissions averaging across CMPUs and across emission unit types (vents, storage vessels, transfer racks, wastewater stream). There is no reason in the boiler and process heater MACT for EPA to restrict the emissions averaging alternative as it has proposed. To do so, will prevent some facilities from taking advantage of the opportunity to avoid otherwise cost-prohibitive compliance options by over-controlling some other emission unit in a more cost-effective combination. Also, by not allowing averaging across the different fuel categories, EPA removes an incentive to burn more natural gas or renewable fuels such as biomass as a strategy to average out emissions from a coal-fired unit.

Some affected units involve multiple boilers operating in different subcategories (e.g. stokers and pulverized coal). These boilers are generally located in separate powerhouses. The goal of emissions averaging is to allow facilities to overcontrol some emissions points while undercontrolling others, thus achieving the required reductions in the most cost-effective manner possible. This could be best achieved by EPA removing the restriction (or clarifying its intent) that such averaging would be allowed for all affected units, regardless of whether the boilers emit through separate or "common stacks."

The legal precursor to introducing emissions averaging is *Chevron U.S.A., Inc. v. NRDC*, 467 U.S. 837 (1984). In *Chevron*, the Supreme Court held that EPA regulations allowing states to treat all of the pollution-emitting devices within the same industrial grouping as though they were encased within a single "bubble" were based on a reasonable construction by EPA. This case opened the door to more specific emissions averaging efforts, such as those implemented in the 1994 Hazardous Organic NESHAP, 59 FR 19,425 (April 22, 1994)(HON Rule). Several rules have followed the HON Rule in authorizing emissions averaging, and the D.C. Circuit has never invalidated the approach. it does not appear that any such authorizations have succumbed to legal challenge. The proposed emissions averaging provisions in the Boiler Rule are directly based on the emissions averaging provisions in the HON.

In the HON Rule, EPA thoroughly examined the legal basis for emissions averaging, and explored the degree of averaging permitted under §112(d) of the Clean Air Act. At the end of its review, EPA concluded that the Clean Air Act "does not define source category, nor does it impose precise limits on the Administrator's discretion to define source." *Id*. EPA further acknowledged that the Clean Air Act does not limit how standards are to be set for a category or subcategory beyond requiring that it be applicable to all sources in a category, be written as a numerical limit wherever feasible, and be at least as stringent as the floor. *Id*.

In promulgating the HON emissions averaging rules, on which the Boiler Rule relies, EPA thus concluded that "the relevant statutory language is broad enough to permit the Administrator to allow sources to meet the MACT through the use of emissions averaging provided the standard applies to every source in the category, averaging does not cross source boundaries, and the standard is no less stringent than the floor." *Id*. Allowing emissions averaging across subcategories within the Boiler Rule is consistent with the parameters established in the HON rule, and reiterated in the Boiler Rule preamble. *See* 75 FR at 32,035. Namely, allowing averaging across subcategories will not result in averaging between (a) different types of pollutants, (b) sources that are not part of the same affected source (see other comments above regarding EPA's proposed definition of affected source), (c) individual sources within a single major source if the individual sources are not subject to the same NESHAP, and (d) existing sources and new sources. *Id*.

There is precedent in MACT standards for allowing averaging across different types of units of a single source. For example, the HON rule allows process vents, storage vessels, transfer racks, and wastewater streams to all be included in an emission average across an affected source. 40 CFR Subpart G. EPA reasoned that averaging needed to be allowed across all emission points (except equipment leaks) in order to provide as much flexibility as possible while maintaining an enforceable emission limitation. 59 FR 19,425. Similar mechanisms have been adopted in other MACT standards. *See, e.g.* Petroleum Refinery NESHAP, 60 FR 43244, 43254 (Aug. 18, 1995)(allowing wide range of emission sources to be averaged, noting that "EPA has the flexibility to allow trading within a facility that includes units in different source categories"); Boat Manufacturing NESHAP, 66 FR 44,218; 44,232 (Aug. 22, 2001).

As in the HON, the compliance methodology can easily accommodate subcategories with different emission limits for a given pollutant. This is done basically by calculating a weighted average allowable mass emission and a weighted average actual mass emission each month using heat inputs or steam production for each unit.

B. The rule should allow for averaging dioxins/furans (D/Fs) and carbon monoxide.

The same legal rationale that supports averaging across subcategories, also fully supports emissions averaging for various HAPs. The same policy rationale applies as well: sources should be allowed the flexibility to over-control at some units at a facility and under-control at others in order to reduce the overall compliance costs for the facility, where no increased risk to the environment results. Allowing this averaging is also consistent with the four averaging criteria described in the preamble.

Averaging across subcategories should be permitted for dioxins/furans and carbon monoxide. A source should be allowed to comply with the dioxin/furan (D/F) standard via emission averaging. While it may not be appropriate to set numerical emission standards for D/F, if the final rule does include such numerical standards, a source with multiple units could choose to comply by installing a post-combustion control (such as powder activated carbon injection) to reduce D/Fs on some units at a facility.

Additionally, carbon monoxide should be included in the emissions averaging provision, since some units may be able to easily meet the proposed CO limits, while, for others, it may impossible. To facilitate its inclusion, the emission limitation for CO should be expressed in an alternative form – lb/MMBtu. For the case of units using CEMS to measure CO, we reference an existing emission averaging provision for NOx found at 40 CFR 76.11. Heat input should be allowed to be determined using either flow monitors (some units subject to the NOx budget trading program have these already) or using fuel factors and diluent monitors per 40 CFR 60 Method 19.

C. The 10% discount factor unless extra flexibility is provided.

EPA imposes a restriction on emissions averaging that requires facilities using that option to meet a standard that is 10% stricter than the otherwise applicable limits. 75 FR 32035. EPA should remove this 10% penalty for using emissions averaging because it is arbitrary, unnecessary for environmental protection and reduces the flexibility that averaging provides. EPA asserts that its inclusion further ensures the allowable emissions are at least as stringent as the MACT floor limits without using averaging. However, EPA offers no demonstration of this in the proposal. Given the accuracy of heat input weighted emission calculations, there is no uncertainty that the average emission rates will be any less stringent than when not using averaging. Because EPA has already determined that the standards in the rule achieve the maximum emission reduction achievable for health and environmental protection, to require an additional 10% reduction of emissions has no basis in the environmental underpinnings of the rule. Because emissions averaging is a compliance alternative, the 10% discount factor constitutes a beyond-the-floor requirement that EPA has not analyzed for its cost, non air quality and energy impacts, as required by CAA §112(d)(2). Finally, although the 10% discount may be perceived as a fair trade-off for the flexibility of emissions averaging, it still lacks a legal basis and creates a disincentive for sources to use this compliance method. Because the proposed limits in this rule are so tight, sources will not be able to ensure an additional 10% reduction in emissions below the limits and imposing this requirement effectively deprives many sources of the availability of the emissions averaging compliance alternative.

One technical amendment that should be made is that it appears the 10% discount factor discussed at 75 FR 32035 of the Proposed Rule should be in the denominator in Equations 1 – 4.

D. Demonstrating compliance on monthly basis for first 12 months is unworkable.

Compliance on a monthly basis during the first twelve months of compliance period is unworkable. Proposed 63.7522(f)(3) requires a facility to generate enough credits to offset the debits each and every calendar month up until 12 months are accumulated and, thereafter, determine compliance on a twelve month rolling average basis. This requirement unnecessarily restricts the utility of the emission averaging provision. For example, in the case where a facility over-controls one boiler while under-controlling the other, there will be months when the facility could not comply. This would certainly be true during a month when the credit-generating unit is down for its periodic maintenance outage. Due to the necessary length of these outages (4-6 weeks), there could conceivably be two or three months in a row where the facility could not comply with proposed averaging provisions. There will be other cases where the credit-generating unit experiences an unanticipated outage and the debit-generating unit is required to operate more to compensate.

For these reasons, this provision should be eliminated. CIBO notes that the HON, which EPA references, includes an annual emission test along with a quarterly emission test where the average emissions must be less than 130 percent of the allowable emissions. Here, EPA acknowledges that a short term average (quarterly) must provide some tolerance as compared to an annual average. CIBO brings this point up, not to suggest to EPA to adopt the HON quarterly test, but to illustrate that EPA emissions averaging provisions have accounted for this issue. Also, CIBO would note that the HON is written for an entirely different industry than the case of boilers and process heaters. Due to the circumstances described above (extended outages while other units take on additional load), a facility using emissions averaging for boilers and process heaters should be subject to only annual compliance determinations.

E. Method for Demonstrating Initial Compliance Should be Amended.

Compliance should be based solely on actual emissions: The proposed provisions require (1) a demonstration that the average weighted emissions is less than 90 percent of the applicable emissions limit assuming each unit is operating at its maximum rated heat input capacity (see Equation 1) and (2) a demonstration each calendar month that the average weighted emissions is less than the applicable emissions limit using the actual heat inputs for that month.

There is no rationale for the first test and it should be eliminated. Other rules that allow emission averaging (again, see the HON), include no such requirement. Such a requirement could be unduly restrictive. For example, a facility may have one older unit and a newer unit which they would like to average. The older unit may have a much lower capacity factor (ratio of actual usage divided by rated capacity) than the newer one. Older units typically have much more space constraints and a facility may be facing steep compliance costs to bring the older unit into compliance and may have an opportunity to over-control the newer unit. Given that the newer unit has a longer remaining life expectancy, such a facility should be incented to over control the newer unit. Yet, Equation 1 may block the facility from taking advantage of the emission averaging flexibility, especially if the older unit has a comparable or even higher rated capacity than the newer unit.

XXXV. Technical Errors

A. Reference should be (b)(3)(i)-(iv) – not (c)(4).

The proposed § 63.7530(b)(3) indicates that a source "must establish parameter operating limits according to paragraphs **(c)(4)(i) through (iv)** of this section." 75 FR 32057 (emphasis added). This should be changed in the final rule to reference (b)(3)(i) through (iv).

B. References to 63.110202 and 63.11203 are incorrect.

The Proposed Rule includes the following text associated with Table 3: "As stated in **§§ 63.11202 and 63.11203**, you must comply with the following applicable work practice standards:". 75 FR 32068 (emphasis added). EPA should clarify whether these section numbers are correct.

C. Definition of Natural Gas.

EPA failed to use the definition of "Natural Gas" that represents the most current thinking of the agency. The definition adopted in § 60.41 Subpart Da, published in the Federal Register on 28th January 2009 (Federal Register /Vol. 74, No. 17 /Wednesday, January 28, 2009 /Rules and Regulations, p. 5079) includes an third definition of Natural Gas to read,

§ 60.41Da Definitions.

> Natural gas means:
>
> (1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or
>
> (2) Liquid petroleum gas, as defined by the American Society of Testing and Materials in ASTM D1835 (incorporated by reference, see § 60.17); or
>
> (3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 34 and 43 megajoules (MJ) per dry standard cubic meter (910 and 1,150 Btu per dry standard cubic foot).

This third definition enables affected sources to burn gaseous fuels that are substantially similar to naturally occurring natural gas without being subject to a variety of additional requirements that impose a regulatory and cost burden on the source. The net impact of this third definition is to promote the beneficial combustion of clean gaseous fuels, such as clean Landfill Gas, which might otherwise be released into the atmosphere or flared. As EPA has indicated in its Landfill Methane Outreach Program (LMOP),

The U.S. Environmental Protection Agency's Landfill Methane Outreach Program (LMOP) is a voluntary assistance program that helps to reduce methane emissions from landfills by encouraging the recovery and beneficial use of landfill gas (LFG) as an energy resource. LFG contains methane, a potent greenhouse gas that can be captured and used to fuel power plants, manufacturing facilities, vehicles, homes, and more.

http://www.epa.gov/lmop/

By failing to adopt the most current definition of "Natural Gas", as incorporated into § 60.41 Subpart Da, EPA is inhibiting sources from burning clean gaseous fuels like Landfill Gas that could be beneficially combusted. EPA should define "Natural Gas" to be identical to the definition in § 60.41Subpart Da.

XXXVI. Additional Source Constraints

A. Effects of Putting Multiple Controls in Series on Units.

The limits being considered for Boiler MACT would necessitate combinations of emission controls that have adverse effects on each other. In other words, the presence of one control technology could prevent a second control technology from operating at optimum performance.

A primary control for Hg emissions involves the injection of activated carbon into the flue gas. The mercury is oxidized on the active sites on the carbon particles. The oxidized form of Hg can then either be recovered by the particulate control equipment, or by the scrubber (since oxidized Hg is soluble). The oxidation reactions only occur at temperatures below about 350ºF. The effectiveness of the activated carbon for oxidizing Hg is dependent upon the amount of time that the carbon has to attract the Hg to one of its active sites.

The use of activated carbon injection for Hg control is negatively affected by the presence of sulfur trioxide (SO_3). SO_3 occupies the active sites on the carbon, taking away those sites from the Hg. Even a few parts per million of SO_3 can have a significant negative impact on the Hg removal that is achieved by activated carbon injection. Small amounts of SO_3 are generated as part of the combustion process for sulfur-containing fuels, while the bulk of the sulfur in the fuel is oxidized to SO_2. However, other control devices, such as CO oxidation catalyst or SCR NO_x reduction catalyst, will convert an additional percentage of the SO_2 to SO_3, resulting in poor Hg removal.

B. Energy and Other Environmental Impacts.

In addition to those discussed above, there are several other issues related to energy and environmental impacts that EPA has failed to consider in the Proposed Rule. First, some facilities cannot discharge waste water from a wet scrubber. These facilities will have to install dry systems, which will likely raise the cost impacts of the rule. In addition, there will be adverse environmental effects for those units that can use wet scrubbers. This is because there are very high water use requirements for scrubbing. Finally, EPA states that 330,000 tons of CO_2 would be reduced under rule. It is not clear where EPA obtained this data or whether the reference should have been to reductions in SO_2. This would be similar to the information EPA includes in Table 14. 75 FR 32041.

C. Recently PSD "Tailoring Rule" Must be Addressed.

Facilities will have to install extensive emission control equipment to meet the proposed Boiler MACT emission limits. Specifically, EPA stated in the preamble that emission control would likely require a fabric filter (FF) plus carbon injection plus wet scrubber control plus combustion improvements or carbon monoxide (CO) catalyst. The installation of this equipment could result in increases in emissions of CO2e or criteria pollutants. The following are examples:

> In general the installation of additional emission control equipment will increase the pressure drop that a boiler's induced draft (ID) fan will have to overcome. If the ID fan is not upgraded the boiler steaming capacity will decrease because the previous air–to-fuel ratio cannot be achieved resulting in the requirement to increase the firing rate of the other facility boilers. Combustion of additional fuel in the other on-site boilers may result in a significant emissions increase triggering PSD.
>
> Operation of additional emissions control equipment will require more electricity. A facility's unused electrical generating capacity would be required to meet this demand thereby requiring additional fuel combustion to generate the steam required for the steam turbine. Additional fuel burning may result in a significant emissions increase triggering PSD.

Facilities may be required to make operational changes in order to meet the Boiler MACT limits that could result in increases in emissions of CO2e or criteria pollutants. The following are examples:

> Fuel switching for multi-fuel boilers may be required to meet the proposed boiler MACT emission limits. A specific example is multi-fuel (e.g. wood and some coal) boiler that has over-fired air and it must combust additional coal in order to decrease the emissions of CO. This change in firing ratio of fuels may result in a significant increase triggering PSD.
>
> A biomass boiler may have to increase its operating target for excess oxygen level in order to decrease emissions of CO in order to meet the proposed boiler MACT emission limit. The result is that the flue gas flowrate increases to a level that is beyond the capability that existing fabric filter can handle reliably and the amount of fuel that can be burned in this boiler is now administratively limited to match the capability of the fabric filter. This requires that the facility operate the back-up natural gas package boilers which have no heat recovery system (e.g. economizer or air heater) to make-up the difference rather than invest in a larger fabric filter needed to meet the proposed Boiler MACT limits.

These are but a few general examples, where there are many more to show how the PSD tailoring rule could be triggered due to changes facilities must make to achieve compliance with the proposed Boiler MACT rule.

Another complicating issue is that EPA has not provided guidance on what is required for BACT for CO2e. A tremendous amount of time and effort has gone into BACT determinations for criteria pollutants over last decade and an equal or larger effort will be required for BACT determinations for CO2e.

The timeline for compliance with Boiler MACT is to install emission control equipment by 2013. Permitting work for installation will be required two or more years prior to 2013, meaning that the PSD tailoring rule will apply to larger facilities within this time frame. Therefore, these larger facilities will have to evaluate whether or not the project to comply with Boiler MACT triggers PSD. In addition, smaller facilities may have to perform this evaluation out of an abundance of caution because there is no guarantee that the higher tailoring rule applicability threshold will be accepted due to the pending evaluation that states are making as to whether or not their laws with statutory thresholds of 100/250 ton per year can be changed. Further, pending legal challenges may result in statutory thresholds as well. Facilities that trigger PSD and their state regulators will be faced with BACT determinations for CO2e and in all likely-hood will have little-to-no guidance from EPA by then. Many states make no decisions about PSD without EPA guidance because they fear that EPA will not agree with their determinations or that some non-government organization will file a legal challenge. The result will be catastrophic because no decisions will be made and the facility will have no certainty for the capital required.

The theme of uncertainty is of critical importance because the long-term viability of a facility and its associated jobs is dependent on capital spending to ensure its continued competitiveness. Other developing countries have none of these rules thereby making investment (e.g. moving a U.S. facility's production to another country) financially attractive and there is far less uncertainty.

In order to remove some of this uncertainty, the EPA should categorically exempt projects required to comply with Boiler MACT from additional regulatory burdens such PSD. Alternatively, EPA should establish that the deadline for compliance with this rule be three years following the issuance of the required construction permits by a site's permitting authority. This would provide relief to the boiler owner in the event that the permitting authority is unable to issue the required permits in a timely fashion, whether due to uncertainty of BACT for CO2e determinations, or due to a backlog of permit applications that are anticipated due to the Tailoring Rule.