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COMMENTS OF THE COUNCIL OF INDUSTRIAL BOILER OWNERS
on
EPA Proposed Reconsidered Rule
National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

EPA-HQ-OAR-2002-0058
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INTRODUCTION

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.

EPA issued the Boiler MACT rule in conjunction with three other interrelated rules, and has maintained the rules on the same notice and comment calendar.[1] For ease of discussion, the four interrelated rules will be referred to as the "Boiler MACT rules."

EPA has solicited comments several times on boiler MACT standards under the Clean Air Act (CAA) § 112. CIBO has submitted comments on legal and practical issues raised by this rule and hereby incorporates by reference its prior comments on the June 2010 Proposed Rule,[2] and Petition for Reconsideration.[3]

PART ONE – TIMING FOR COMPLIANCE AND COMMENTS

I. STAY OF THE MARCH 2011 RULE AND NO ACTION ASSURANCE

EPA should stay the effect of the March 2011 Boiler MACT rule and issue additional guidance or no enforcement assurance to address compliance exposure faced by sources during the period before EPA issues a Final Reconsideration Rule.

EPA had delayed the effective dates of the March 2011 Final Boiler MACT and CISWI rules.[4] However, on January 9, 2012, the U.S. District Court for the District of Columbia vacated EPA's Delay Notices,[5] and any compliance obligations for sources covered by the Boiler MACT and CISWI rules became effective immediately. EPA recognized that the vacatur triggered some

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[1] National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, 76 Fed. Reg. 80,598 (Dec. 23, 2011) (to be codified at 40 C.F.R. pt. 63) (Boiler Rule); National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers, 76 Fed. Reg. 80,532 (Dec. 23, 2011) (to be codified at 40 C.F.R. pt. 63) (Area Source Rule); Commercial and Industrial Solid Waste Incineration Units: Reconsideration and Proposed Amendments; Non-Hazardous Secondary Materials That Are Solid Waste, 76 Fed. Reg. 80,452 (Dec. 23, 2011) (to be codified at 40 C.F.R. pt. 241) (CISWI and NHSM Rule).

[2] *See* CIBO Comments on Boiler MACT Proposed Rule, EPA-HQ-OAR-2002-0058-2702.

[3] *See* CIBO Petition for Reconsideration on Boiler MACT Final Rule, EPA-HQ-OAR-2002-0058-3334.

[4] Industrial, Commercial, and Institutional Boilers and Process Heaters and Commercial and Industrial Waste Incineration Units; Delay Notice, 76 Fed. Reg. 28662 (May, 21, 2011).

[5] Opinion, Sierra Club v. EPA, No. 11-1278 (DDC Jan. 9, 2012).

compliance obligations, and on January 18, 2012 EPA announced in a letter to Senator Wyden[6] its plan to address the implications of the vacatur. Then on February 7, 2012, EPA issued a No Action Assurance memorandum that addresses some – but not all – of the implications of the vacatur.[7] EPA's memorandum assures sources in a limited scope of circumstances that their failure to have met a deadline to file an initial notification would not be the basis of an enforcement action brought by EPA, given that the deadline fell during the period when the Boiler MACT and CISWI rules were not in effect. In the letter to Senator Wyden, EPA asserts that for any "permitting or compliance challenges" arising from the vacatur, EPA will issue a stay for 90 days or longer, and in the event of lawsuits arising from the vacatur, EPA is "confident" that it has the legal tools to address those matters. Notwithstanding its assurances, EPA's memorandum does not alleviate many pressing continuing compliance concerns faced by sources because the rules remain in effect.

This ongoing uncertainty is created by the timing of the four interrelated rulemaking proceedings and the fact that the rules are now in effect and will be in effect until EPA completes the rulemaking proceedings and issues Final Reconsidered Rules in Spring 2012. One issue, for example, that EPA did not address in its memorandum is the circumstance faced by sources that combust alternative materials in their boilers. With March 2011 definitions of "fuel" and NHSM now in effect, and boiler and incinerator standards in effect, a source that currently combusts a material that has been defined as waste would presumably be subject to CISWI standards. However, that same material may be redefined as fuel under the Final Reconsidered NHSM Rule, and the unit would be classified as a boiler. The effectiveness of the rules, and the imposition thereby of regulatory obligations, have created compliance exposure for sources that EPA could and should eliminate. CIBO and other organizations in meetings and discussions with EPA have explained the ongoing compliance exposure during this interim period between the rules going into effect and issuance of final rules that will replace the March 2011 rules. EPA should alleviate these concerns by staying the effect of the rules during this interim period and issuing further guidance or no enforcement assurance that addresses these concerns.

II. COMPLIANCE DATES SHOULD BE RESET

EPA proposes to reset the compliance date for existing sources to 3 years after publication of the final reconsideration rule and for new sources, to the later of 60 days after publication of the final reconsideration rule or startup. 76 Fed. Reg. 80605.

Sources need a substantial period to come into compliance and CIBO strongly supports resetting the dates. Internal planning for compliance with major rules requires involvement of personnel at all levels of the company, and in the case of this major rule, will require major capital projects at many facilities covered by this rule. CIBO has commented in earlier comments at length on the need for sufficient time for the complex undertaking of retrofitting a major boiler facility, including compliance planning, engineering design, capital approval, equipment purchase, installation and testing, all in advance of the compliance date.

[6] *See* EPA Letter to Sen. Wyden, Jan. 18, 2012. Appendix A.
[7] *See* EPA No Action Assurance letter, Feb 7, 2012. Appendix B.

Here, because EPA issued an immediate Notice of Reconsideration of the rule,[8] sources understood as of the publication of the March 2011 Final Rule that there would be amendments to the rule that could very well alter compliance strategies. At the time, it was unclear whether the rule would change considerably from the final version, and with respect to which sources and emission limits. One significant element of the BMACT rule that would clearly undergo change, based in part on EPA's flawed or incomplete data, was the inventory of units in some subcategories, and their emission limits. In addition, several clear problems in the March 2011 Final NHSM rule made it clear that the definitions of NHSM and fuel were highly likely to be amended. Changes to correct data and likely revisions to the fuel definition would clearly affect the inventories of units in boiler subcategories and therefore floor calculations and emission limits. Under those circumstances, it would not have been rational for sources to develop compliance strategies and begin the complicated, costly process of compliance with a rule that EPA had announced would be changed.

As anticipated, EPA has addressed several significant elements of the March 2011 Final NHSM rule, which have the effect of reclassifying sources between the incinerator and boiler categories and among subcategories in each rule. Even during the development of and comment period on the Proposed Reconsidered NHSM rule, EPA issued three interpretive letters that directly affected subcategory populations. 76 Fed. Reg. 80473. Among the sources whose classifications were directly affected are CIBO members. And EPA went on to propose other significant changes in the fuel definition that must be accounted for by sources in their compliance plans. Even publishing the Final Reconsidered NHSM rule, however, will not fully determine the status as waste or NHSM of many materials currently being used as fuel, and that rule provides a petition process to make those determinations. Sources that are unsure about the status of their materials will petition EPA for determinations of the status of their materials, and on the basis of those determinations, the sources will then know whether their continued use of those materials will classify the source as an incinerator or boiler. CIBO has urged EPA to establish a timeline for completion of the initial round of waste/fuel determinations, although the Proposed Reconsidered NHSM Rule does not indicate a date-certain by which sources will have final decisions regarding the status of their materials.

III. THE PERIOD PROVIDED FOR COMMENT ON THE RULE WAS ARBITRARILY SHORT

Under basic principles of due process and administrative law, EPA has an obligation to provide the public with a reasonable opportunity to comment on proposed rules. Specifically, Congress requires EPA to give the public "a reasonable period . . . of at least 30 days" in which to comment on "any regulation" promulgated under the CAA.[9] By the clear terms of the CAA, Congress indicates that 30 days is the minimum time necessary to give the public a reasonable opportunity to evaluate a proposed rule and provide adequate feedback to the Agency. Thus, a comment period meeting the statutory 30-day minimum would be reasonable for a single, ordinary proposed rule. Here, EPA has violated the clear terms of the CAA and deprived sources

[8] National Emission Standards for Hazardous Air Pollutants; Notice of Reconsideration, 76 Fed. Reg. 15266 (March 21, 2011).
[9] CAA §307; 42 U.S.C. § 7607(h) (2006).

of a means to adequately protect their interests and rights in the administrative and judicial processes by providing 60 days of comment for four complex interrelated rules.

Under reconsideration, the rules are no less complex then when they were first proposed in June 2010. A 60-day comment period is particularly inadequate given their complexity, breadth of applicability, and economic impact. EPA has added data on reconsideration for 300 additional sources that must be reviewed and sources face the pressures of sorting complex data and developing thorough comments that address very technical issues. Although EPA released the signed rule proposals almost one month prior to their publication in the Federal Register, it did not provide the majority of the supporting documentation for the proposed rules until publication on December 23, 2011, just two days before the holidays, effectively shortening the comment period.

The four proposed rules under reconsideration make for an enormously broad and costly proposal, which would have a significant economic impact across numerous and diverse sectors of the US economy, with the boiler MACT rule alone imposing capital costs of more than $5 billion and affecting nearly 200,000 sources, according to EPA. 76 Fed. Reg. 80622.

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

Sources have done the best under the circumstances to develop thoughtful comments on their concerns and the specific requests for comment EPA made in the four rules, and where necessary or appropriate, and where time permitted, to compile data to support its positions.

<u>PART TWO – SPECIFIC ISSUES</u>

I. CATEGORIES AND SUBCATEGORIES

A. Limited-use units

EPA seeks comment on how a limited use subcategory defined with a 10% capacity factor would qualify for work practice standards in lieu of emission limits. CIBO in its Petition for Reconsideration, sought a change in the limited-use definition to be based on a 10% annual capacity factor, and a work practice standard for these units. EPA did not rely on a capacity factor in the Proposed Reconsidered Rule, but in the Utility MATS rule, EPA used an 8% factor, which CIBO supports. A capacity utilization factor of 10 percent was chosen for the 2004 Boiler MACT final rule as the best means of defining a limited use unit. This definition is equally appropriate for the current rule. A capacity factor versus hour of operation is a reasonable method for defining the limited use subcategory.

[10] How Costs Were Determined for CIBO Boiler MACT Study, January 2012, Appendix C.
[11] *See* January 18, 2012 Letter of 27 Organizations to EPA, Appendix D.

We offer the following additional points in support of a capacity factor approach:

- Limited use units are likely to be operated infrequently. Many will be in cold-standby until their operation is warranted. This requires, typically, a 2 to 4 hour startup, depending on the size of the boiler, etc. During the start-up period, the boiler is not producing steam for use in a turbine or by heating/process load customers. In general, fuel will be burned for a short period of time (5 to 10 minutes) a couple of times an hour, then the boiler "buttoned up" in between to keep the heat in to allow the metal to slowly warm in order to prevent metal stress. *As currently defined, each hour of start-up would constitute an "operating hour", decreasing the available hours for a limited use boiler to operate.*
- From a practical compliance perspective, monitoring hours of operation is an administrative challenge. It is more effective in a permit for a source to accept a fuel consumption limit, and also easier to monitor electronically. While IC engines are equipped with a non-resettable hour meter, the same is not true for boilers. In addition, monitoring fuel usage is already required in the Boiler MACT and other permit requirements, so this requirement would not create the additional burden that monitoring hours of operation would.
- 40 CFR 75, Appendix E, provides relief from the burdensome NOx continuous emissions monitoring requirements of the Acid Rain Program for affected units that limit the capacity factor to less than 10% on a 3-year average. This is an example of where EPA implemented a work practice standard based on a capacity factor instead of the standard requirement.
- In the RICE NESHAP, EPA implemented a work practice standard for emergency and limited use units.

B. Hybrid suspension/grate boilers

In its Petition for Reconsideration, CIBO requested that the definition of a 'suspension/grate' boiler specifically include the words 'spreader stoker' as a type of combustion system in a suspension/grate boiler in addition to those with independent suspension burners.

The Proposed Reconsideration Rule states that "Stoker means a unit consisting of a mechanically operated fuel feeding mechanism, a stationary or moving grate to support the burning of fuel and admit under-grate air to the fuel, an overfire air system to complete combustion, and an ash discharge system. This definition of stoker includes air swept stokers. There are two general types of stokers: underfeed and overfeed. Overfeed stokers include mass feed and spreader stokers. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, suspension burners, and fuel cells are not considered to be a stoker design." 76 Fed. Reg. 80,655.

The Proposed Reconsideration Rule also indicates that EPA agrees that "dutch ovens and pile burners should be included in the same subcategory and suspension burners should be a separate subcategory. Therefore, the EPA is proposing separate emission limits for the combustion-based pollutants for these subcategories." 76 Fed. Reg. 80609.

The Proposed Reconsideration Rule revised the definition of "hybrid suspension grate boiler" to include the italicized sentence:

> a boiler designed with air distributors to spread the fuel material over the entire width and depth of the boiler combustion zone. *The fuel combusted in these units exceed a moisture content of 40 percent on an as-fired basis.* The drying and much of the combustion of the fuel takes place in suspension, and the combustion is completed on the grate or floor of the boiler. Fluidized bed, dutch oven, and pile burner designs are not part of the hybrid suspension grate boiler design category.

76 Fed. Reg. 80,652. This revision assists in better defining the source. CIBO recommends that the definition further specify that the moisture content be 40 percent on average, as the precise moisture content will fluctuate somewhat over time. CIBO suggests the addition in red below to the text:

> *The fuel combusted in these units exceed an average annual moisture content of 40 percent on an as-fired basis.*

C. GAS 2 subcategory

In this proposed rule, EPA seeks comment on the added fuel specification to the final rule that would allow units combusting gases not defined as "Gas 1" gases to qualify as Gas 1 units by demonstrating that the fuels combusted meet a fuel specification. 76 Fed. Reg. 80607.

1. Gas 1 fuel specification

As set forth in its Petition for Reconsideration and Comments on the Proposed Rule, there is no rational reason to not provide similar regulatory treatment for gaseous fuels that have similar constituents and emissions impacts as natural gas. In response to EPA's question whether additional parameters should be included in the Gas 1 fuel specification, CIBO urges that no additional criteria should be included because there is no rational basis for these to be added.

2. Landfill gas

In its Petition for Reconsideration, CIBO stated that landfill gas should be categorized as a Gas 1 gaseous fuel. In its Proposed Reconsidered rule, however, EPA has excluded landfill gas from the Gas 1" category. 76 Fed. Reg. 80,655. Units that combust landfill gas should be treated as Gas 1 units because landfill gas emissions are comparable to emissions from Gas 1 gases – natural gas and refinery gas – and therefore there is no rational basis to treat landfill gases differently, as noted in CIBO's Petition for Reconsideration.

Alternatively, if EPA does not qualify landfill gas as Gas 1, CIBO supports the mechanism for a unit to demonstrate its fuel specifications enable it to qualify for Gas 1 treatment. CIBO supports the removal of the H2S fuel specification from this demonstration mechanism because H2S is not related to potential hazardous air pollutants that will be emitted from combusting gaseous fuels. *Id.* at 80,609.

In applying these fuel specifications to landfill gas, data show that landfill gas consistently contains less Hg than the permitted 40 mm/m^3. Therefore, landfill gas should be given a categorical exemption from the certification and testing requirements of the fuel specification mechanism.

To the extent that landfill gas is categorized as neither Gas 1 nor given a categorical exemption from the fuel specification mechanism, EPA should change the fuel specification mechanism and allow for alternative testing and certification measures. In the proposed Reconsideration Rule, a Gas 2 unit can secure Gas 1 treatment by: (1) certifying that the fuel will "never" exceed the Hg specification of 40 mm/m³, or (2) conduct monthly testing of the fuel. *Id*. at 80,641-42. Rather than certifying that a fuel will "never" exceed the Hg specification, a unit should have to certify that, based on available data, it is reasonably unlikely that the fuel will not exceed the Hg specification. Additionally, if a unit elects the testing option, the frequency of testing should be reduced if the unit's prior tests show consistent compliance with fuel specifications. Additionally, EPA should expand the allowable test methods listed in the *Boiler MACT Reconsideration Proposal*, 76 Fed. Reg. at 80,666 (Table 6) to include the allowable methods used to gather the Hg data that affected facilities supplied to EPA in response to the Section 114 requests (EPA Methods 29, 30A, or 30B at 40 CFR part 60).

D. Definition of "Hot Water Heater"

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

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

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

E. Small source exemption

EPA rejected a request to exempt very small (between 2 and 10 MM Btu/hr) oil-fired units. However, EPA has proposed to change the frequency for tune-ups (following the initial tune-up) for boilers or process heaters that are less than 5 MMBtu/hr to a tune-up once every 5 years (76 FR 80644, Dec. 23, 2011). For new units, EPA has proposed to remove the requirement for the initial tune-up, considering that new units will likely be tuned during the initial startup process as part of commissioning. For facilities with a large number of small units, completion of tune-ups on a biennial basis can quickly become a logistics issue, due to the need to schedule periods where the boilers and process heaters can be shutdown and tuned without undue disruption to the operation of the facility. For such small boilers and process heaters, we believe that a reduction in the tune-up frequency from every two years to every 5 years is appropriate, as emissions from these boilers and process heaters are small, and allowing a reduced tuning frequency will reduce the cost of the rule. Therefore, we support these changes, as they minimize burden on small sources with minimal emissions impact.

However, EPA should promulgate a de minimis exemption, not merely a work practice standard, for small boilers and process heaters of up to 10 MMBtu/hr or less. *Alabama Power Co. v.*

Costle, 636 F.2d 323, 400 (D.C. Cir. 1979), clearly establishes EPA's authority to fashion *de minimis* and administrative necessity exemptions. In addition to the logistical issues involved with shutting down multiple small units in a facility at the same time, there is the considerable cost involved with performing the tune-ups. This significant cost produces only minimal corresponding reductions in HAP emissions. Tune-ups required under the current final and proposed rules will have only a limited effect on the HAP emissions from these small units. At least one CIBO member facility has estimated the cost of performing biennial tune-ups at $20,000 per ton and quintennial tune-ups at $8,000 per ton. The tune-up requirement results in a disproportionate expense in a very small portion of industry-wide HAP emissions.

In addition, EPA is proposing to create a new subcategory for seasonally operated boilers. For these seasonally operated boilers, EPA is proposing to require a tune-up every five years (following the initial tune-up). Seasonally operated boilers would be defined as follows:

> "Seasonal boiler means a boiler that undergoes a shutdown for a period of at least 7 consecutive months (or 210 consecutive days) due to seasonal market conditions. This definition only applies to boilers that would otherwise be included in the biomass subcategory or the oil subcategory."

We support the addition of a seasonal boiler subcategory. These boilers are used in seasonal agricultural operations or for comfort heat and typically operate only about 100 days per year, so the number of hours actually operated over a 5-year period is much less than a boiler in normal operation. Therefore, a 5-year tune-up frequency for these units is appropriate and is comparable to the tune-up frequency required for units that operate continuously.

However, this subcategory should also cover units that only operate during short periods of high electricity demand in the summer and for semi-annual capacity testing requirements. Because of the semi-annual testing required by the electric utility, the units will not meet the proposed criterion of being completely shut down for 7 consecutive months, but would otherwise be considered seasonal units and their limited operation is consistent with EPA's intent when developing this subcategory. Therefore, EPA should revise the definition of seasonal boiler to allow intermittent operational testing (e.g., up to 15 days) during the 7 month period. This would allow biomass or oil units at area sources that have availability requirements to ensure that the unit is available on short notice.

F. Changing status as boiler or incinerator

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

EPA seeks comment on the provisions included in the final CISWI rule regarding changing fuels being combusted and thereby changing the status of a unit as an incinerator or boiler, particularly on whether the provisions should include further clarification on the timeline and regulatory requirements of a fuel switch. Additionally, EPA is soliciting comment on an alternative time period for switching frequency. 76 FR 80460.

CIBO opposes EPA's prescriptive approach to boiler or incinerator status. This constrained approach is not necessary to ensure compliance with the applicable standards. Instead, the constraints result in EPA governing economic decisions related to supply and demand, and deprive regulated sources the flexibility to make sound economic decisions related to their operations.

The practical effects of the regulation are far-reaching. For example, if a facility burns a waste /fuel mix, which is typical, and is operating under the CISWI regulations, if for some reason the waste component of their fuel supply becomes unavailable, solid fuel boilers (e.g., coal) would not be able to meet the emission requirements under CISWI (e.g. sulfur dioxide) and would have to shut down operations (or find an alternate source of energy) until they are permitted to switch back to an appropriate standard for their solid fuel. Many waste streams are not available year round and their supply is dependent upon production schedules at other entities. Also, a facility may inadvertently burn a material that is a waste or later becomes classified as a waste, and might be forced to shut down or operate under the CISWI regulations for six months during periods while no waste is being burned. This presents an additional and significant risk to attempting to burn alternative fuels. Another complication is that many units do not fire solid waste until the unit is started up and at steady state.

To remedy these damaging effects, a provision should be added that allows a facility to elect to either (1) comply with CISWI at all times or (2) comply with CISWI while burning solid waste but comply with otherwise applicable standards under section 112 of the Clean Air Act while not burning solid waste. The Hazardous Waste Combustor MACT (see 40 CFR 63.1206(b)(1)(ii) and 63.1209(q)) provides a helpful referent.

This will also alleviate another problem caused by the EPA's decision that work practice standards are not adequate for the regulation of sources during their startup and shutdown periods. Because EPA has stated it cannot use work practice standards during periods of startup and shutdown, compliance with CO emission limits along with other parameters such as sorbent loading in spray dryer absorbers will be very problematic. EPA should resolve this problem by allowing sources that encounter these issues to elect to comply with section 112 standards during all times that solid waste are not being combusted or, alternatively, during just the startup and shutdown periods.

If a source elects one of these options, it would have to conduct all necessary performance testing and establish continuous compliance monitoring systems and recordkeeping systems to comply with both the section 129 (CISWI) and the section 112 rules. Facilities can easily document which mode of operation they are in (by tracking solid waste feed rates) and readily show compliance with the applicable standard. There are no compliance assurance issues with allowing this flexibility, as sources are able to demonstrate during what periods solid waste is in the combustor.

II. EMISSION LIMITS AND FLOOR DETERMINATIONS

A. Floor setting methodologies and variability

The methodologies EPA has relied on to establish emission limits have resulted in some new sources and existing sources having the same standards. For example, the HCl limit is the same for solid fuel new sources and existing sources. This likely occurred because the 99 UPL for the new unit data is higher than the 99 UPL for the existing unit data and EPA choose the calculated existing unit limit as the standard that both types of units must meet. EPA's approach is arbitrary. EPA should instead set both the existing and new unit standards at the new unit 99 UPL in order to adequately reflect variability.

EPA set many of the new source limits using one 3-run stack test. EPA should consider variability and use the UL instead of the UPL statistical calculation. This approach is appropriate and justified because sources will be required to meet the new source limits at all times. EPA should also consider fuel variability data for all units setting new source floors and that variability should be included in the calculated emission limits. As CIBO indicated in its earlier comments and Petition for Reconsideration of the Final Boiler MACT Rule, variability is important in setting achievable emission limits.

B. Liquid fuel subcategories

EPA has proposed to "separate subcategories for heavy liquid-fired and light liquid-fired units for PM and CO, pollutants that are dependent on combustor design." 76 Fed. Reg. 80,608. CIBO supports creating different subcategories for heavy and light liquid-fired units. Heavy liquid boilers and light liquid boilers have different equipment designs, operations, and emissions. Thus, it is appropriate to create different subcategories for them.

In its Petition for Reconsideration, CIBO stated that the CO limit in Boiler MACT for oil fired units was unachievable. The CO limits are still unachievable in some cases and these standards do not meet the CAA requirement that they be achievable by existing units.

EPA seeks comment on whether Hg and HCl should have limits for heavy and light liquid fuels, not just all liquid. 76 Fed. Reg. 80608. CIBO has supported EPA subcategorizing for light versus heavy liquid fuels in both its comments on the proposed rule and in its Petition for Reconsideration. There are many technical arguments for this sub categorization to separate the liquid fuel units given that HAP content can vary greatly. Furthermore, as CIBO states in its Petition, units can purchase the highest costing liquid fuel available, that provides the lowest PM and CO emission, but cannot meet both the HCl and HG emission limits that EPA is imposing. If units are already using cleaner fuel, EPA should create a standard that holds that as sufficient to meeting limits.

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

C. Solid fuel subcategories —HCl and Hg

Fuel flexibility is an important factor in the operation of many industrial facilities, and fuel cost is usually one of the top three costs of doing business. Many facilities have committed to a single solid fuel, such as coal, but other facilities burn a mixture of fuels. EPA should set limits for HCl and Hg for solid fuel-fired units that ensure the maximum number of sources can achieve the limits and that do not disadvantage users of any one particular fuel.

EPA has the discretion and should include a fuel variability factor in the MACT floor analysis for the solid fuel subcategory HCl and Hg limits so fuel pollutant content variability among the top performers is adequately considered. This approach would make achievability of these standards more viable, while reflecting the real world operational and fuel variability that boilers experience.

D. Gas 2 Emission Limits

CIBO supports the EPA's proposal to drop H2S fuel specifications, for the purpose of regulating a source under Gas 1 standards as opposed to Gas 2 standards, from the proposed Reconsideration Rule. 76 Fed. Reg. 80,609. In its Petition for Reconsideration, CIBO stated that "[s]ince H2S . . . has limited relevance to HAP emissions other than partial conversion to SO2, its selection as a Gas 2 to Gas 1 qualifier seems to be arbitrary." In its Reconsideration Rule, EPA agreed that "the key contaminant for demonstration of comparability from a HAP perspective is Hg and that the H2S fuel specification that was finalized does not provide a direct indication of potential HAP from combustion of gaseous fuel. Accordingly, the EPA is proposing a fuel specification based only on the Hg level in the gaseous fuel . . ." 76 Fed. Reg. 80,609 (2012 Reconsideration Rule). CIBO supports this proposal.

E. Dioxin/Furan Emission Limits

CIBO supports the EPA's decision to apply work practice standards for dioxins/furans emissions instead of applying numeric emission limits. 76 Fed. Reg. 80,606 (2012 Reconsideration Rule). As CIBO stated in its Petition for Reconsideration, levels of dioxins/furans in coal-fired utility boilers are below the detection levels of the EPA test methods, and, furthermore, dioxin/furan levels in industrial boilers are similarly low. Because detection of dioxins/furans is so uncertain, CIBO urged EPA to adopt work practice standards in lieu of numeric emission limits. EPA has since "re-assessed the dioxin/furan data sets and has determined that, similar to data for electric utilities for which work practice standards were proposed for dioxins/furans, the large majority of the emission measurements for all of the subcategories are below the level that can be accurately measured using EPA Method 23. . . [T]he EPA concludes that emissions from industrial boilers and process heaters cannot practicably be measured, and the EPA is now proposing work practice standards in place of numeric emission limits for dioxin/furan." 76 Fed. Reg. 80,606 (2012 Reconsideration Rule). CIBO supports this proposal.

F. PM Limits for New Solid Fuel Boilers

In the Reconsidered Boiler MACT Rule, EPA proposes to retain the final standard of 0.0011 lb/ MMBtu, but to split the units intosubcategories. As CIBO indicated in its Petition for Reconsideration of the Final Boiler MACT Rule, the PM limits finalized for new solid fuel-fired boilers are unachievable. Newer coal-fired units do not come close to meeting the standards.

CIBO believes that the limits are skewed based on data from one of the units relied on to set floor, which is not representative of units in the category. The boiler that set the solid fuel floor for PM, designated as IAArchersDanielsMidlandDesMoines is a small bubbling bed boiler burning low ash coal and equipped with an oversize baghouse. The baghouse is designed for greater than nameplate boiler capacity whereas the boiler typically operates at less than nameplate capacity. As such, it is extremely conservative design is not representative of the community of solid fuel boilers. The data from that boiler should not be relied on, as it is outlier data from a unit equipped with controls that are not considered standard for the unit.

G. CO limits

Strict CO levels will not result in greater reduction of emissions of other organic compounds. CIBO has heard from vendors that they cannot guarantee many of the coal, liquid, and gas CO limits. In addition, some of our members with top performing units equipped with sophisticated combustion control like over-fired air, cannot say with certainty that they will meet the limits 100% of the time. CO varies significantly with load and fuel quality to the point that some of the units EPA is relying on to set the MACT floors cannot comply all year round.

Carbon monoxide is the most common product of incomplete combustion (PIC), and because of its associated chemical kinetics, is one of the most difficult PICs to oxidize completely. As such, CO emissions have historically been used as an indicator of the quality of the combustion process. The concept is that low CO emissions equate to low emissions of other organic compounds. While this is true in general, the mechanisms by which CO is formed and destroyed in the combustion process are different than for other organics. As such, in cases where other organic compounds have been completely oxidized, CO concentrations may still be elevated. While the tendency is to think that further reductions in CO emissions will improve the quality of the combustion, and in turn minimize emissions of other organic compounds, this is not necessarily true. Instead, forcing CO emissions lower and lower ends up over-constraining the combustion process, resulting in other air quality concerns, without achieving corresponding reductions in emissions of organics.

Most boilers are designed to mix fuel and air at an appropriate ratio, and to provide sufficient residence time for the fuel to combust completely. Obviously, these factors are fuel-dependent, as a gaseous fuel will require less time for complete combustion than a liquid fuel, which in turn requires less time to burn than a solid fuel. The need for longer residence time is why the radiant sections in solid-fuel fired boilers are larger than for gas-fired units. The size of the boiler is typically optimized to allow for complete combustion, while minimizing the cost of construction materials. If the construction cost were not a concern, a new boiler could be designed with additional residence time to complete the combustion process and minimize CO emissions.

Unfortunately, increasing the size of the furnace is not an option for existing units. For these units, the strategy for reducing CO emissions is typically to raise the level of excess oxygen. The increase in oxygen concentration has two positive effects. First, it acts to overcome poor distribution of the fuel. Second, it increases the concentration of oxygen in the gas, which speeds up the combustion reactions, allowing more complete combustion to occur for the same residence time.
However, there are a number of negative impacts associated with operating a boiler at higher levels of excess oxygen. Many boilers do not have sufficient fan capacity to run with elevated excess oxygen at the high end of the load range. Therefore, these units would not be able to operate at capacity under this strategy. A site might have to add another boiler to offset the reduction in steam generating capacity.

The minimization of excess oxygen in boiler applications is a key feature for maximizing boiler efficiency. The boiler efficiency is defined by the amount of combustion air that is present, and the difference between the ambient temperature and the stack exhaust temperature. The more air that is heated up through the combustion process, the more heat is lost to the atmosphere, causing the boiler to be less efficient. A less efficient boiler will require more fuel to be fired to produce a given amount of steam. The additional fuel firing results in higher operating costs, and higher greenhouse gas emissions.

Minimizing the level of excess oxygen is also a primary strategy for reducing NOx emissions from a boiler. The NOx formation mechanisms are dependent upon the temperatures in the flame zone, and the stoichiometry. Reducing the level of excess oxygen reduces the average gas temperature, which reduces the rate at which the nitrogen in the air dissociates. As such, there is less monatomic nitrogen available to be oxidized to form 'thermal NOx'. Similarly, if there is less oxygen present, the monatomic nitrogen is less likely to be oxidized (and more likely to react with a second monatomic nitrogen to form diatomic nitrogen). This reduces both the amount of thermal NOx, and the 'fuel NOx' (NOx that is formed by the release of fuel-bound nitrogen). Therefore, increasing the level of excess oxygen will result in higher NOx emissions.
Low-NOx burner (LNB) designs for some applications manipulate the stoichiometry within the flame to minimize NOx formation. These designs establish a fuel-rich zone for the initial phase of combustion, and then add air at a later stage in the outer regions of the flame. In the initial phase, there is not sufficient oxygen available to form significant amounts of NOx, and in the secondary phase, the flame is much cooler, which also inhibits NOx formation. However, using natural gas combustion as an example, these burners often operate with CO emissions up to 10 ppmvd in the upper part of the load range. At mid loads, the CO begins to increase to near 50 ppmvd, and at low loads, it may exceed 100 ppmvd. As the EPA is continually establishing a lower ozone standard, many more facilities will likely be installing low-NOx burners.

Some boilers only produce significant CO when they are experiencing load variations. All of the testing that is being used to establish the floor was conducted at steady high load conditions. A boiler may have very low CO emissions at steady high load, but significant CO emissions as the load varies. As such, the CO data used to establish the floor may not be representative of normal boiler operation and a low CO limit may not be achievable by even the top performers under all operating scenarios, including operation at loads less than 100%.

CIBO sought the input of a leading supplier of burners for gas- and liquid-fired boiler applications to determine what CO emission guarantees would be provided for their installations. For applications for Gas 1 category fuels, the CO emission guarantee is generally 50 ppmvd (@ 3% O2). For ultra-low NOx burner applications, the CO emissions often exceed 50 ppmvd up to 50% load. For liquid-fired applications, the supplier offers a CO emissions guarantee of 100 ppmvd (@ 3% O2), for loads ranging from 25% to 100%. Gas 2 sources have a greater variety of emissions characteristics due to the differences in fuel composition, which makes control of excess air more difficult. Most of these other gases tend to be lower heating value that natural gas or refinery gas and burn at lower flame temperatures. They are also commonly limited on the pressure that is available, therefore there is not as much flexibility on how the gases are injected and mixed in the burner. With these factors the potential for CO emissions tends to be higher on these gases than for natural gas or refinery gas. The supplier's default CO guarantee is 400 ppmvd (@ 3% O2) at loads from 25-100% for Gas 2 fuels. Given the right furnace conditions, the guarantee may be as low as 100 ppm. CO guarantees are only provided on a "steady state" basis, since as burners change load the fuel-air ratio changes until the controls can react and the system stabilizes. If a boiler is equipped with CEMS and operates in a load-following mode, the transient conditions may generate CO levels that would inflate the 30-day rolling average.

EPA itself has already reached the conclusion that forcing CO emissions below 100 ppm does not force organic HAP emissions to ultra-low levels in the Hazardous Waste Combustor NESHAP rulemaking. As the Agency states at 70 FR 59462 (October 12, 2005):

> *"We explained at proposal why the carbon monoxide standard of 100 ppmv and the hydrocarbon standard of 10 ppmv are appropriate floors. See 69 FR at 21282. The floor level for carbon monoxide of 100 ppmv is a currently enforceable Federal standard. Although some sources are achieving carbon monoxide levels below 100 ppmv, it is not appropriate to establish a lower floor level because carbon monoxide is a conservative surrogate for organic HAP. Organic HAP emissions may or may not be substantial at carbon monoxide levels greater than 100 ppmv, and are extremely low when sources operate under the good combustion conditions required to achieve carbon monoxide levels in the range of zero to 100 ppmv. (See also the discussion below regarding the progression of hydrocarbon oxidation to carbon dioxide and water). As such, lowering the carbon monoxide floor below 100 ppmv may not provide significant reductions in organic HAP emissions. Moreover, it would be inappropriate to establish the floor blindly using a mathematical approach—the average emissions for the best performing sources—because the best performing sources may not be able to replicate their emission levels (and other sources may not be able to duplicate those emission levels) using the exact types of good combustion practices they used during the compliance test documented in our data base. This is because there are myriad factors that affect combustion efficiency and, subsequently, carbon monoxide emissions. Extremely low carbon monoxide emissions cannot be assured by controlling only one or two operating parameters."*

CIBO agrees that CO is an appropriate surrogate for organic HAP, but we believe HAP emissions are minimized at levels well above the 3 to 10 ppm CO limits proposed for Gas 2 and liquid boilers. At CO levels below about 100 ppm, differences in organic HAP emissions are negligible. Where achievable emission limitations for organic HAP that properly reflect source category and unit variability are derivable from representative data, CO should continue to be used as the compliance surrogate for organic HAP. However, the CO limits should reflect the fact that the organic HAP concentration becomes insensitive to CO level below some value (e.g., 100 ppm).

For coal units, EPA reached a similar conclusion in the recently finalized MATS rule. Many coal-fired boilers emit CO in the range of 50-100 ppm while emitting less than 1 ppm THC. This fact is supported by EPA's boiler ICR databases. Thus, a boiler required to reduce CO to meet the numerical standard could install an oxidation catalyst with no evidence that VOC will be reduced since there is little emitted to begin with.

EPA hired a contractor to conduct an extensive pilot study to truly determine the expected emission profiles and relationship of non-dioxin organic HAP and CO for coal-fired units. This test program included a variety of types of coal and is titled "Surrogacy Testing in the Multi-Pollutant Research Control Facility", dated March 30, 2011. The excerpt from the preamble to the proposed MATS rule where EPA articulates its rationale for work practice standards in lieu of CO limits for coal-fired utility boilers is shown below.

> *"Tests were also conducted to examine potential surrogacy relationships for the non-dioxin/furan organic HAP. The amounts of Hg, non-Hg metals, HCl, HF, and Cl2 in the flue gas are directly related to the amounts of Hg, non-Hg metals, chlorine, and fluorine in the coal. Control of these components generally requires downstream control technology. However, the presence of the organics in the flue gas is not related to the composition of the fuel but rather they are a result of incomplete or poor combustion. Control of the organics is often achieved by improving combustion conditions to minimize formation or to maximize destruction of the organics in the combustion environment.*
>
> *During the pilot-scale tests, sampling was conducted for semi-volatile and volatile organic HAP and aldehydes. On-line monitors also collected data on THC, CO, O2, and other processing conditions. Total hydrocarbons and CO have been used previously as surrogates for the presence of non-dioxin/furan organics. Carbon monoxide has often been used as an indicator of combustion conditions. Under conditions of ideal combustion, a carbon-based or hydrocarbon fuel will completely oxidize to produce only CO2 and water. Under conditions of incomplete or non-ideal combustion, a greater amount of CO will be formed.*
>
> *With complex carbon-based fuels, combustion is rarely ideal and some CO and concomitant organic compounds are expected to be formed. Because CO and organics are both products of poor combustion, it is logical to expect that limiting the concentration of CO would also limit the production of organics. However, it is very difficult to develop direct correlations between the average concentration of CO and the amount of organics produced during the prescribed sampling period in the MPCRF (which was 4 hours for the pilot-scale tests described here). This is especially true for*

low values of CO as one would expect corresponding low quantities of organics to be produced. Samples of coal combustion flue gas have mostly shown very low quantities of the organic compounds of interest. Some of the flue gas organics may also be destroyed in the high temperature post combustion zone (whereas the CO would remain stable). Semi-volatile organics may also condense on PM and be removed in the PM control device.

The average CO from the pilot-scale tests ranged from 23 to 137 ppm for the bituminous coals tests, from 43 to 48 ppm for the subbituminous coal tests and from 93 to 129 ppm for the Gulf Coast lignite tests. However, it was difficult to correlate that concentration to the quantity of organics produced for several reasons. The most difficult problems are associated with the large number of potential organics that can be produced (both those on the HAP list and those that are not on the HAP list). This is further complicated by the organic compounds tending to be at or below the MDL in coal combustion flue gas samples. Further, there are complications associated with the CO concentration values. Some of the runs with very similar average concentrations of CO had very different maximum concentrations of CO (i.e., some of the runs had much more stable emissions of CO whereas others had some excursions, or ``spikes,'' in CO concentration). For example, one of the bituminous runs had an average CO concentration of 69 ppm but a maximum concentration of 1,260 ppm (due to a single ``spike'' of CO during a short upset). Comparatively, another bituminous run had a higher average CO concentration at 137 ppm but a much lower maximum CO value at 360 ppm.

In the pilot tests, the THC measurement was inadequate as the detection limit of the instrument was much too high to detect changes in the very low concentrations of hydrocarbons in the flue gas.

EPA is proposing work practice standards for non-dioxin/furan organic and dioxin/furan organic HAP. The significant majority of measured emissions from EGUs of these HAP were below the detection levels of the EPA test methods, and, as such, EPA considers it impracticable to reliably measure emissions from these units. As the majority of measurements are so low, doubt is cast on the true levels of emissions that were measured during the tests. ….For the non-dioxin/furan organic HAP, for the individual HAP or constituent, between 57 and 89 percent of the run data were comprised of values below the detection level. Overall, the available test methods are technically challenged, to the point of providing results that are questionable for all of the organic HAP. For example, for the 2010 ICR testing, EPA extended the sampling time to 8 hours in an attempt to obtain data above the MDL. However, even with this extended sampling time, such data were not obtained making it questionable that any amount of effort, and, thus, expense, would make the tests viable. Based on the difficulties with accurate measurements at the levels of organic HAP encountered from EGUs and the economics associated with units trying to apply measurement methodology to test for compliance with numerical limits, we are proposing a work practice standard under CAA section 112(h)." 76 Fed. Reg. 25039

This study is as applicable to industrial boilers as it is to utility boilers. The EPA testing appears to support this conclusion since no correlations could be made at low CO emission levels associated with normal operation. This is further justification for not requiring ultra-low CO limits for coal-fired boilers in the industrial Boiler MACT, such as the 41 ppm limit proposed for existing pulverized coal boilers, the 56 ppm limit proposed for existing fluidized bed boilers, and the even lower CO limits proposed for new coal-fired units. These are prime examples of MACT limits the manufacturers have told our members they cannot guarantee. Real impacts on organic HAP emissions are not achieved by pressing ultra-low CO limits on fossil fuel combustion units compared to normal operating levels, but higher emissions of organic HAP might only occur with high levels of CO associated with malfunctions, equipment failures, or fuel interruptions. Therefore, while EPA can calculate a MACT Floor CO emission limit for the industrial boilers and process heaters as proposed, there is no defensible driver to impose such low emission limits, and modifying the floor setting procedure or allowing alternatives to accommodate higher allowable emission rates appears justified.

Mandating a work practice standard instead of an emission limit gets more to the core of the MACT rule: minimizing emissions while ensuring efficient operation. As such, CIBO requests EPA consider replacing the numerical CO emission limit in reproposed Boiler MACT with a work practice standard similar to the approach used in the Utility MACT (77 FR 9369, February 16, 2012). In the preamble, EPA discusses their belief that "…the work practice standard will result in actions being taken that will reduce the emissions of these (organic) HAP."

However, if EPA continues to pursue imposition of CO limits on ICI boilers and process heaters, in addition to the proposed adjustments to the CO emissions limitations and the proposed alternative CO emissions limitations for units with CEMS, EPA should consider additional alternative approaches to setting standards for CO. Discussed below are several additional alternative approaches. Each approach is well within EPA's authority to adopt and each would result in emissions limitations that better reflect the limitations of the available data and better accommodate variability that even the best performers unavoidably exhibit.

1. EPA Should Determine that Data From CO CEMS Cannot be Used to Show Compliance with Stack Test-based CO Emissions Limitations

As discussed in more detail elsewhere in these comments, for units that already have CO CEMS for reasons unrelated to the IB MACT, compliance with the IB MACT stack-test-based CO emissions limitations would be difficult to maintain. Stack tests are required to be run under representative operating conditions, which typically is defined as operating at or near full load consistently for the duration of the stack test. In sharp contrast, CEMS take emissions data on a near-continuous basis, which means CEMS emissions measurements reflect significant variability in emissions (for example, due to load swings and low load conditions) that was not measured during the stack tests used to set the CO standard. This problem is not overcome by statistical manipulation of the CO standard, such as accounting for variability using the UPL method, because such statistical methods unrealistically extrapolate only from the variability measured during stack tests and the variability between stack tests. In other words, this is a classic "apples and oranges" situation where emissions data from CO CEMS are incompatible with emissions data from stack tests used to set the CO standard.

One way for EPA to resolve this incompatibility is to determine that emissions data from CO CEMS are not credible evidence for purposes of assessing compliance with the IB MACT stack-test-based CO emissions limitations. As the Agency explained in the "credible evidence rule," data and information derived from methods other than the specified reference test method (so-called "non-reference test data") are relevant to showing compliance only to the degree that "the appropriate reference test would have shown a violation." 62 Fed. Reg. 8314, 8323 (Feb. 24, 1997). Because the IB MACT CO standards are based on stack test data, and because the stack tests on which the standards are based were required to be conducted during representative operating conditions (*i.e.*, consistently operating at or near full load), then by definition CO CEMS data taken during periods of operation that do not reflect "representative operating conditions" are not data that are relevant to showing compliance with the standards.

In other words, the stack test data on which the standards are based reflect operation during a narrow, limited, and optimum set of conditions. Thus, CO CEMS data that are taken during periods of operation that do not reflect those conditions are not relevant to determining whether an affected source is in compliance with the standard.

2. For Sources Opting For The Stack-Test CO Limit, EPA Could Establish A Performance Standard Applicable To Periods Between Tests

As another alternative compliance method for the stack test CO limits, EPA could establish a performance standard that would apply during the periods between stack tests. Such a standard could consist of a numeric value indicative of good combustion – such as oxygen or CO levels in the furnace or stack. Under this approach, EPA would also specify appropriate monitoring methods, such as oxygen meters or CO CEMS. But, if parametric monitoring indicated an exceedance of the performance standard, such an exceedance would not constitute a violation if appropriate corrective action were taken within a reasonable time after the exceedance was measured.

In concept, such an approach would be analogous to bag leak detection systems on baghouses, which EPA routinely requires in its standards. When a leaking bag is detected, EPA's rules typically do not define such an event as a violation. Instead, the affected source is required to replace the leaking bag and only might be found in violation if this corrective action is not taken within a specified period. So, there is clear precedent for applying this concept to the IB MACT stack test CO standards.

EPA would have ample justification to adopt this approach as a work practice under § 112(h). Among other things, EPA is authorized to adopt work practices under § 112(h) when "the application of measurement methodology to a class of sources is not practicable due to technological and economic limitations." That is clearly the case with the IB MACT stack-test-based CO emissions limitations. While it is true that certain relevant constituents such as oxygen and CO can be measured, the "application" of such methods is not technologically practicable because the data that are collected cannot reasonably be used to show compliance with a stack test CO limit. As explained above, the data largely would be taken during periods when the affected source was not operating under the same conditions as existed during the stack tests used to set the standards (again, creating an irreconcilable "apples to oranges" problem).

Available methods such as oxygen or CO monitoring are not economically practicable because the "apples to oranges" problem cannot be solved merely by spending more money refining the methods.
Thus, EPA has authority and justification to set performance standards for the periods between periodic stack tests.

3. EPA Should Determine That A Standard No Lower Than 100 ppm CO Is Adequate To Assure Complete Control Of Volatile HAPs

It is well established that CO is harder to combust than the volatile HAPs that might be emitted by industrial boilers and other similar combustion sources. In this respect, CO actually is a conservative surrogate for volatile HAPs from industrial boilers because measured CO emissions can rise up to a certain point without a corresponding increase in volatile HAP emissions. As mentioned in the previous section, studies have shown that volatile HAP emissions remain extremely low at measured CO levels of up to about 100 ppm.

Thus, while it is certainly possible to reliably measure CO to levels well below 100 ppm, EPA would be justified in setting the IB MACT CO limits at no lower than 100 ppm because lower values would not result in demonstrably lower volatile HAP emissions. This squares with DC Circuit precedent on the use of surrogates because the court has held that EPA may use surrogates as long as the Agency can establish a necessary relationship between emissions of the surrogate and emissions of the underlying HAPs. There is nothing in that precedent that demands that the relationship must be <u>linear</u>. In the case of CO and volatile HAP emissions from industrial boilers, credible data show that the relationship is highly nonlinear at low levels. It would be rational and in keeping with court precedent for EPA to set a CO standard that reflects this nonlinear relationship.

4. EPA could endorse a petition process for unit-specific CO limits for units that cannot implement cost-effective modifications to comply

EPA could allow for a petition to the permitting authority for determination of a unit-specific CO emission limit if it is determined that a boiler or process heater cannot attain the final rule CO emission limit without major unit redesign, oxidation catalyst addition with associated stack gas reheat and increased fuel usage, exceedance of an applicable NOx standard, or derating the unit. As EPA has monetized benefits for only PM2.5 and its precursors (NOx and SO2) it is apparent that requiring drastic reductions in CO emissions to the detriment of NOx emissions is not the desired outcome. Further, units close to Class I areas will be sensitive not only to increases in NOx emissions but also to implementation of NOx controls that might result in ammonia slip.
The process of determining a unit-specific CO limit could include:

- performing a tune-up according to a standard industry protocol (e.g., ASME PTC 4-2008, Fired Steam Generators, which provides rules and instructions for conducting performance tests of fuel fired steam generators)
- inspection and maintenance of the boiler/process heater and its fuel supply system to ensure they are in good operating condition,

- testing for CO emissions over the range of operating conditions to determine a site-specific CO limit and appropriate operating parameter limits, and
- establishment of a protocol for ongoing unit operation to ensure good combustion practices.

5. At a Minimum, EPA Should use the 99.9 UPL to set Stack Test-Based CO Limits

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

> *"In the final rule, the EPA selected the use of a 99.9 percent confidence interval for calculating the MACT floor for CO emissions. A petitioner requested reconsideration of this selection given the fact that the EPA used a 99 percent confidence interval for all of the other emission limits in the final rule. The petitioner pointed out that if the data are highly variable, the 99 percent confidence interval should adequately reflect the variability of emissions as well as for the data sets for other pollutants. In the development of the final rule, the 99.9 percent confidence interval was selected in part because the standards covered periods of startup and shutdown, while the data did not reflect CO emissions during those periods. While the EPA finalized work practice standards for startup and shutdown periods, the selection of the confidence interval was not revisited due to time constraints. The EPA is now proposing to use a 99 percent confidence interval in order to maintain a consistent methodology with the development of the MACT floors for other pollutants, and because optional CO CEMS-based limits are being proposed that would allow sources additional flexibility in meeting the requirements of the rule."*

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

The reasons for using a 99.9 UPL for setting the CO MACT floor cited in the preamble to the March 2011 Boiler MACT rule remain valid:

> *"For CO, EPA considered several comments from industry and States, which provided both quantitative and qualitative comments on how CO emissions vary with load, fuel mixes and other routine operating conditions. After considering these comments EPA determined that a 99.9 percent confidence level for CO would better account for some of these fluctuations. While a good deal of CO data are available, at least for some of the*

subcategories, the data show highly variable emissions that can result from situations beyond the control of the operator, such as fuel moisture content after a rain event, elevated moisture in the air, and fuel feed issues or inconsistency in the fuel. The higher confidence level selected for CO is intended to reflect the high degree of variability in the emissions." 76 Fed. Reg. 15628.

Therefore, EPA should retain the use of the 99.9 UPL for calculating CO limits.

H. Total Hydrocarbon Alternative to CO Limit

A total hydrocarbon alternative (THC) standard is needed for coal-fired boilers unable to meet the CO limit. Although EPA has not elected to reconsider (this issue was included in CIBO's petition for reconsideration) its decision to not include a THC option, we are aware that the Agency will be getting significant comment from the regulated community that the proposed CO limits for coal-fired boilers will prove to be problematic. THC is an alternate surrogate to EPA's proposed CO surrogate for non-dioxin organic HAPs. However, EPA, in its response to comments on the June 4, 2010 proposed rule, stated that its Office of Research and Development does not support the use of THC as a surrogate for organic HAP from industrial boilers. No other explanation is given and EPA has failed to respond adequately to a significant comment that goes to the issue of sources' ability to comply with the rule. Some coal boilers have high (>100 ppm) CO levels but very low (<1 ppm) THC. To avoid forcing owners of these boilers to make large expenditures to the combustor to reduce CO and then add post-combustion control to reduce co-laterally increased NOx emissions, EPA should set an alternative THC limit. Sources, would then conduct stack tests to demonstrate compliance with the THC limit and operate O2 trim systems as an operating parameter.

I. Total selected metals

1. Solid fuel units

CIBO supports EPA's decision to include a total selected metals (TSM) option for solid fuels into the Propose Reconsideration Rule. In its Petition for Reconsideration, CIBO stated that the "TSM option would offer the opportunity for sources to achieve low metal HAP emissions similar to those achieved with the use of PM as a surrogate for HAP metals, but potentially at a lower cost." Furthermore, CIBO noted that a TSM option provides for additional flexibility for Boiler MACT compliance.

EPA has proposed "TSM limits for each subcategory of units that combust solid fuels or Gas 2 fuels." 76 Fed. Reg. 80,606. Sources will also have the compliance option of meeting PM emission limits as well. EPA noted "the TSM measurement, which directly quantifies the HAP metals rather than relying on a surrogate, is a more direct measurement of HAP than PM and is, therefore, appropriate as a pollutant group for regulation with numeric emission limits." *Id.* Furthermore, EPA will include 8 (excluding cobalt and antimony), as opposed to 10, metals for measurement because more test data are available for the eight metals. *Id.*

The TSM option for solid fuels preserves flexibility and may lower compliance costs for sources. TSM does not provide any less environmental protection, but is simply another way for sources to measure compliance with non-mercury metals emission limits.

2. Liquid fuel units

EPA did not provide a TSM option for liquid fuels. "For the light liquid, heavy liquid and non-continental liquid units subcategories, we are not proposing alternative TSM emission limits. Instead, we are proposing that these units meet the filterable PM emission limits in all instances." 76 Fed. Reg. 80,606. EPA determined that the emission data were too limited for TSM in this subcategory, but added that if it receives sufficient data indicating that TSM is appropriate, it would consider adopting a TSM option for liquid fuels as well. *Id*.

CIBO supports EPA's efforts to gather additional data to evaluate the possibility of a TSM option for liquid fuels. However, based on the analysis and conclusion EPA reached for solid fuel fired units, CIBO would expect that liquid fired units would lead to the same conclusions, based on logical conclusions with respect to these fuels and their typical emissions characteristics.

III. START-UP, SHUTDOWN, MALFUNCTION

A. Start-up/Shutdown

In the Final Boiler MACT Rule, EPA finalized work practice standards for periods of startup and shutdown. 76 Fed. Reg. 80,602. As stated in our comments on the Final Boiler MACT Rule, EPA has the authority to authorize work practices. Furthermore, as EPA indicated in the preamble to the Final Boiler MACT Rule, work practices are appropriate standards for periods of startup and shutdown. See 76 Fed. Reg. 15,642.

1. Good combustion practices

In the Reconsidered Boiler MACT Rule, EPA is proposing to expand work practice standards for periods of startup and shutdown. Specifically, among other requirements, EPA is proposing that sources employ good combustion practices. 76 Fed. Reg. 80,602. CIBO supports the good combustion practices as proposed, but EPA should make clear that safety must be of central importance, and should include this critical caveat in its requires practices. consistent with safe operation

> These practices require these actions: You must employ good combustion practices and demonstrate thatgood combustion practices are maintained by monitoring O2 concentrationsand optimizing those concentrations as specified by theboiler manufacturer; you must ensure that boiler operators aretrained in startup and shutdown procedures, including maintenanceand cleaning, safety, control device startup, and procedures to minimizeemissions; and you must maintain records during periods ofstartup and shutdown and include in your compliance reports the

O2conditions/data for each event, length of startup/shutdown and reasonfor the startup/shutdown (i.e., normal/routine, problem/malfunction,outage).

76 Fed. Reg. 80,602.

2. Minimal stable operating load

In the Reconsidered Boiler MACT Rule, EPA is also proposing definitions for "startup" and "shutdown." 76 Fed. Reg. 80,541. (2012 Reconsidered Rule). EPA is proposing to define ''startup'' as "the period between the state of no combustion in the boiler to the period where the boiler first achieves 25 percent load (i.e., a cold start)." 76 Fed. Reg. 80,654. EPA is proposing to define ''shutdown'' as "the period that begins when a boiler last operates at 25 percent load and ending with a state of no fuel combustion in the boiler." 76 Fed. Reg. 80,654. EPA notes in the Reconsidered Major Source Rule, that the proposed definitions of "startup" and "shutdown" are intended to ensure that units cannot cycle in and out of startup or shutdown." 76 Fed. Reg. 80,615. (Reconsidered Boiler MACT Rule) Furthermore, EPA indicates that the definitions should provide "clarity regarding which periods of operation are subject to the work practice standards rather than numeric emission limits and the associated requirements." 76 Fed. Reg. 80,615. (Reconsidered Boiler MACT Rule) EPA is soliciting comment on the proposed definitions.

The proposed revision attempts to place all boilers into the same basket in specifying a 25% load threshold. This is not technically correct or practical on many fronts. How boilers "behave" is a function of fuel type, furnace and boiler design (combustion method), and operating methodologies. For example, some boilers have a minimum stable operating load that is higher than 25 percent, (e.g., stable operation for a stoker boiler may not be reached until 60 percent load). Additional examples include the fact that:

- Most solid fuel boilers do not reach stable operations until 50% load or higher while some oil and gas burners can function as low as 20% load for long duration.
- In facilities with solid fuel boilers that have significant steam load fluctuations (say between night and day), a boiler in hot standby is required to be ready to take on the added load within a short period of time. This standby boiler is "banked", which means the bed of fuel is hot and burning slowly, but no steam is being produced. No combustion air is being supplied. All that it then takes to bring the boiler on line is to initiate the input of combustion air to increase the combustion rate. Depending upon conditions, boilers can be in "banked" mode for hours to several days.
- Solid fuel units, particularly older anthracite units, will have a fire on the grate for several days to allow for slow heat-up of the refractory and other critical metal components. The slow heat up rate is necessary to prevent material damage to the unit. No steam is being produced during the warm-up period.
- Some facilities may have oil fired boilers that are sized correctly for winter heating loads, but are too big summer steam loads. Often, the unit may cycle on and off on the high pressure cutout because the facility steam load is below minimum firing rate for the unit.

- As previously mentioned, some oil boilers have burners that can function reliably down to 20% firing rate and do so for extended periods. In the case of low summer loads as noted above, these units may operate for extended periods between 20% and 25% load.
- Oil fired units in wet layup may use burner heat to generate natural circulation to mix up and circulate boiler water chemicals. No steam is generated during these events. The burner is operated at minimum firing rate which, as noted above, could be below 25%. The time of operation depends upon the size of the boiler and the burner rating at minimum fire.

Considering this, EPA should revise the startup definition to allow facilities to determine the minimum stable operating load on a unit-specific basis and include the minimum stable operating load that defines startup and shutdown and the proper procedures to follow during startup and shutdown in a site-specific plan. Establishment of the minimum stable operating load on a site-specific basis is analogous to setting other boiler and control device operating parameter limits on a site-specific basis.

We believe the following types of concepts could be used as being indicative of a boiler reaching the end of a startup period (the beginning of a startup would occur with first introduction of fuel with combustion in the furnace):

- Boiler firing its primary fuel for a period of time adequate to provide stable and non-interrupted fuel flow, stable and controlled air flows, and adequate operating temperatures to allow proper fuel drying and air preheat as applicable.
- Emissions controls in service with operating parameters such as flow rates and temperatures being controlled and stable.
- Boiler supplying steam to a common header system or energy user(s) at normal operating conditions including pressure, temperature, and above minimum operational output flow rate, as applicable to the unit.

Similarly, we believe the following types of concepts could be used as being indicative of a boiler beginning a shutdown period (the end of a shutdown would occur with the cessation of combustion of any fuel in the furnace):

- Cessation of introduction of the last remaining primary fuel to the furnace, whether or not a supplemental support fuel is being used.
- Cessation of emissions control system sorbent or other reagent injection.
- Lowering the fuel firing rate to the point that automatic control is no longer effective or possible.
- Lowering of operating rates to the point that emissions control systems no longer can be controlled or be effective due to low flow rates, low temperatures, or other issues.
- Lowering boiler output to the point that steam no longer meets operational required conditions of pressure, temperature, or flow.

Boiler owners/operators should establish specific operating conditions and parameters defining startup and shutdown in standard operating procedures for each affected unit so that it is clear when each unit is in either startup or shutdown mode. Procedures should also be used to guide operations purposely through startup or shutdown periods so that protracted periods in startup or shutdown mode beyond that envisioned in the procedures are avoided. Each startup and shutdown should be documented relative to elapsed time and timing of actions prescribed in the procedure so that problems are effectively identified and corrected in a timely manner.

EPA should not include a maximum time in the startup and shutdown definitions. Sources covered by the rule are highly variable and the amount of time needed for startup and shutdown are different depending on the specific unit. EPA has adopted a source-specific approach in other programs, such as Part 75 (40 CFR Part 75 Appendix A 6.5.2.1). If EPA does include definitions for startup and shutdown based on a load threshold, it would be appropriate to institute a source specific approach much like in Part 75.

B. Malfunction

Unlike startup and shutdown periods, EPA has determined that malfunctions should not have work practice standards and has instead provided for an affirmative defense. 76 Fed. Reg. 80,629.

Given that malfunctions are essentially the same as periods of startup and shutdown, work practice standards should also apply. As CIBO points out in its Petition, EPA recognizes in both the Boiler MACT and Area Source rule, "that it is not feasible to require stack testing – in particular, to complete the multiple required test runs – during periods of startup and shutdown due to physical limitations and the short duration of startup and shutdown periods. Operating in startup and shutdown mode for sufficient time to conduct the required test runs could result in higher emissions than would otherwise occur." 76 Fed. Reg. 15577, 15642. It is irrational to view malfunctions any different than startup/shutdown periods. As such, EPA should establish work practice standards for malfunctions. The rule is unreasonable as it is and subjects sources to the risk of noncompliance especially given the fact that malfunctions are unavoidable and unpredictable.

In doing so, EPA has inappropriately placed the burden on the source to prove that excess emissions were caused by a malfunction. As CIBO asserted in earlier comments, malfunctions are in all material respects the same as startup and shutdown and therefore clearly meet the CAA definition for when work practice standards are appropriate. CAA §112(h). EPA should establish a work practice standard that requires pre-determined malfunction plans with practices and procedures for potential malfunctions; require reporting of any malfunctions; address any malfunctions not contemplated and add to the plan and address as appropriate.

Alternatively, if EPA rejects such work practice standards and, instead, includes an affirmative defense for malfunctions, the terms of the defense need to be changed. First, a source should not have to prove it meets every criterion to successfully claim the affirmative defense. Rather, the different criteria should be factored in evaluating whether the excess emissions should be excused.

The proposed criteria in the Reconsideration Rule for establishing an affirmative defense, which did not change from the Final Rule, are poorly defined and do not reflect on whether a malfunction actually occurred. For example, the requirement that sources rely on overtime workers to address the malfunction, 76 Fed. Reg. 80,629, objectively proves nothing. The personnel onsite at the time of the malfunction event may not be the personnel with the expertise to resolve the malfunction, yet if they do not remain onsite as overtime personnel, under EPA's structure, that source fails to meet one of the indicia of a malfunction. Moreover, the affirmative defense criteria in some cases impose draconian obligations on malfunctioning sources without any regard for their cost-effectiveness. For example, the source must show "[r]epairs were made as expeditiously as possible . . . excess emissions (including any bypass) were minimized to the maximum extent practicable . . . [a]ll possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment and human health." 76 Fed. Reg. 80,629 (emphasis added). This could lead to the EPA or a court imposing extreme MACT regulations on sources during malfunctions. Overall, the provisions impose vague obligations on malfunctioning sources which will lead to inconsistent interpretations in different jurisdictions, and lack precision that is fundamental to an adequate defense in an enforcement proceeding.

IV. FUEL SWITCHING

A. Fuel switching is not a MACT control technology

In the Proposed Boiler MACT Rule, EPA considered and rejected the use of fuel switching as a control technology for determining MACT floors. EPA explained:

"We first considered whether fuel switching would be an appropriate control option for sources in each subcategory. We considered the feasibility of fuel switching to other fuels used in the subcategory and to fuels from other subcategories. This consideration included determining whether switching fuels would achieve lower HAP emissions. A second consideration was whether fuel switching could be technically achieved by boilers and process heaters in the subcategory considering the existing design of boilers and process heaters. We also considered the availability of various types of fuel." 75 Fed. Reg. 32,019.

In concluding that fuel switching was not appropriate, EPA stated that "[a]fter considering these factors, we determined that fuel switching was not an appropriate control technology for purposes of determining the MACT floor level of control for any subcategory. This decision was based on the overall effect of fuel switching on HAP emissions, technical and design considerations discussed previously in this preamble, and concerns about fuel availability." 75 Fed. Reg. 32,019.

EPA made a similar determination when considering fuel switching within subcategories, concluding that while some pollutants may be reduced by switching fuels, other pollutants might increase. 75 Fed. Reg. 32,019. Overall, EPA noted that "fuel switching to cleaner solid fuels or to liquid or gaseous fuels is not an appropriate criteria for identifying the MACT floor emission levels for units in the boilers and process heaters category." 75 Fed. Reg. 32,019.

While EPA indicated that "[f]uel switching to natural gas is a potential regulatory option beyond the new source floor level of control that would reduce HAP emissions from non gas-fired units," the agency concluded it would not be appropriate. 75 Fed. Reg. 32,030. EPA noted that fuel switching to natural gas would reduce HAP emissions, but was not an appropriate beyond-the-floor option. 76 Fed. Reg. 32,026. EPA reasoned that switching to natural gas was not appropriate beyond –the-floor option because (1) natural gas supplies are not available in some areas; (2) "[t]he cost for fuel switching is over double the cost of the floor approach while the emission reductions associated with fuel switching are approximately the same." 76 Fed. Reg. 32,026.

EPA noted that some petitions it received for reconsideration of the Final Boiler MACT Rule, suggested that EPA continue to allow averaging across subcategories in cases where fuel switching has been used to achieve compliance because such an approach would encourage fuel switching to cleaner fuels. In the 2012 Reconsidered Boiler MACT Rule, EPA has requested comment on the "potential benefit of this suggested approach, and how such an approach could be justified and incorporated into the rule." 76 Fed. Reg. 80,617

B. Emissions Averaging for Repowered Boilers

The emissions averaging provisions should allow owners or operators of a solid fuel or liquid fuel boiler to repower (convert) that boiler to natural gas (gas 1) within the averaging process.

EPA, in response to input from stakeholders, solicits comment on a suggested approach to allow an existing unit that is converted to natural gas to be included in an emissions average with other similar existing units. EPA's request for comment is shown below:

> *Stakeholders asked the EPA to consider, for units that are retrofitted to switch to natural gas as a compliance option, allowing those units to average emissions with units of the original unit design. These parties suggested that continuing to allow such averaging would be consistent with EPA's general approach of specifying emission standards for affected facilities, but otherwise allowing the facilities to comply however they see fit. They also pointed out that this may allow for more effective controls overall. For example, they suggested that without allowing for averaging of units that switch to cleaner fuels as a compliance option, natural gas conversion is a less attractive option than if such averaging was allowed, because a facility would not have the ability to offset emissions using that unit. In this case, these stakeholders believe that installing controls that result in fewer emissions reductions than switching to natural gas may be a perverse outcome. They suggested that continuing to allow averaging across subcategories in cases where fuel switching has been used to achieve compliance would instead encourage fuel switching to cleaner fuels, which is environmentally beneficial. The EPA is requesting comment on the potential benefit of this suggested approach, and how such an approach could be justified and incorporated into the rule.*

76 Fed. Reg. 80617. CIBO strongly supports allowing companies to convert coal-fired units to cleaner-burning gas fuels without revoking that unit's eligibility for emissions averaging with remaining coal-fired units. For some companies, switching boilers from coal to cleaner-burning natural gas will offer the best environmental and business outcome because it will (1) result in greater emission reductions than what will be achieved through a standard end-of-stack control option and (2) it will allow facilities to implement a more cost-effective solution, conserving

their capital for productive use in growth projects that may assist with the nation's economic recovery.

Moreover, this approach is fully consistent with both the express language of §112, which gives EPA considerable discretion in establishing source subcategories, and §112's underlying intent, which is to promote a "maximum degree of reduction in emissions of the hazardous air pollutants while "taking into consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements." 42 U.S.C. §7412(d). Given EPA's support for emissions averaging between coal-fired units where operators elect to invest in capital-intensive pollution control technologies, EPA should support emissions averaging where operators select fuel switching as the most effective compliance strategy. While natural gas conversion is not available to every facility in every region, where it is technically and economically feasible, it offers the ability to reduce emissions far below the levels available with end-of-stack controls alone. [12]

EPA's policy should not discourage or penalize companies that adopt fuel switching as a voluntary compliance strategy. Yet, EPA's proposed rule does just that. Currently, the rule would restrict emissions averaging to boilers in the same subcategory (*see* §63.7522(b)). Under our understanding of the proposed rule, a solid or liquid fuel boiler converted to natural gas could not be part of an emissions average with other solid or liquid fuel boilers at a site because that boiler would no longer belong to the same subcategory of boilers with which it would be averaged. This situation is further complicated by EPA's proposal to subcategorize solid and liquid fuel boilers even more narrowly, a step that will reduce the opportunities for averaging and decreases compliance options with little environmental benefit.

Such bureaucratic limits and distinctions put form over substance and are nonsensical from both a legal and policy perspective. EPA's mandate under §112 is to promote a maximum degree of reduction in emissions of the hazardous air pollutants "taking into consideration compliance costs, and any non-air quality health and environmental impacts and energy requirements." EPA should not mandate which technologies companies select to lower their net emissions from

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[12] Here, it is important to distinguish between a mandatory fuel switching policy, as would occur if EPA presumed fuel switching to be a universal option for the purpose of setting MACT floor and beyond-the-floor standards, and voluntary fuel switching as a compliance strategy option. EPA has correctly recognized that it would be inappropriate to consider fuel switching as a universally-available factor for the purposes of setting MACT floor and beyond-the-floor standards. Specifically, EPA's 2010 proposed rule included a lengthy discussion of the pros and cons of fuel switching as a basis for setting floor and beyond the floor standard, ultimately dismissing the approach based on: 1) uncertainties regarding whether such a strategy would result in a net reduction of HAP emissions on a category-wide basis; 2) whether fuel switching would be technically achievable on a category wide basis; and 3) whether alternative fuels like natural gas would be reasonably available to all units within a category. See 75 Fed. Reg. 32,019 ("After considering these factors, we determined that fuel switching was not an appropriate control technology for purposes of determining the MACT floor level of control for any subcategory. This decision was based on the overall effect of fuel switching on HAP emissions, technical and design considerations discussed previously in this preamble, and concerns about fuel availability"). EPA's conclusion remains sound with respect to setting subcategory-wide standards. As numerous commenters have noted in the administrative record, the significant diversity of engineering, technological, and fuel-availability infrastructure available to units within any given subcategory make fuel substitution an impractical, if not arbitrary and capricious, basis for setting industry-wide floor or beyond-the-floor standards.

existing sources, particularly where EPA's policy results in *less* pollution control. EPA should eliminate the restriction on averaging across subcategories and focus on reducing emissions.

Alternatively, EPA can eliminate the unintended impact of its cross-subcategory policy by using its considerable statutory authority to develop subcategories that allow fuel switching and other innovative emissions reduction strategies. As the Agency itself has acknowledged, EPA has broad discretion to establish such categories and subcategories as it deems appropriate, *Id.* §7412(c)(5), and to distinguish among classes, types, and sizes of sources within a category or subcategory in establishing standards. *Id.* §7412(d)(1). There is nothing in the statute, or in ensuing case law interpreting EPA's discretion, that would prevent the Agency from setting categories and subcategories based on their operational characteristics at a specific point in time. *See, e.g.*, Utility MACT at 411; *Northeast Maryland Waste Disposal Authority v. EPA*, 358 F.3d 936, (D.C. Cir. 2004) ("[The Clean Air Act] gives the EPA broad discretion to differentiate among units in a category. . . , provided the EPA indicated why such a subcategorization was appropriate."); *Davis County Solid Waste Mgmt. v. EPA*, 101 F.3d 1395, 1411 (D.C. Cir. 1996) ("Class is an ambiguous term. It is not defined in the Clean Air Act, and the dictionary definition -- "a group, set, or kind marked by common attributes" -- could hardly be more flexible.").

Using this flexibility, EPA should revise the subcategories used for the MACT rule to establish that, for purposes of emissions averaging, an existing unit belongs to the subcategory within which it fits as of the rule proposal date (December 23, 2011). Suggested regulatory language is shown below:[13]

> §63.7522(a): As an alternative to meeting the requirements of 63.7500 for particulate matter, hydrogen chloride, or mercury on a boiler or process heater-specific basis, if you have more than one existing boiler or process heater in any subcategory, you may demonstrate compliance by emissions averaging, if your averaged emissions are not more than 90 percent of the applicable emission limit, according to the procedures of this section. <u>For purposes of this section, an existing boiler or process heater that is part of any *subcategory listed in Table 2 to this subpart* as of December 23, 2011 may be included in an emissions average group with other existing units within these subcategories even if the boiler or process heater is converted to be part of the *unit designed to burn gas 1 subcategory* after December 23, 2011. Such a converted boiler or process heater shall not be required to conduct subsequent annual performance tests as required by §63.7515(b) but such a unit shall be subject to the other applicable requirements in this subpart for units designed to burn gas 1.</u> You may not include new boilers or process heaters in an emissions average.

Heretofore, the Agency has expressed its concern that it may lack authority to allow averaging across subcategories or that such allowance would be inconsistent with its policy in providing emissions averaging options in other rules., However, as discussed in the preamble to the HON (Hazardous Organic NESHAP for the Synthetic Organic Chemicals Manufacturing Industry (SOCMI) (Federal Register, April 22, 1994, starting on page 19425)), the rule EPA cites as

[13] As reflected in the recommended language, an existing natural gas unit should not be able to convert to a solid fuel boiler (burning at least 10 percent solid fuel) and using this as a strategy for compliance.

precedent for emissions averaging, EPA has itself acknowledged its wide discretion to define "source" broadly. Indeed, in the case of the HON, EPA defined the source category to include all emission points relating to SOCMI production at a facility – a range of emission points and technologies far more diverse than the differences between coal-fired and converted coal-to- gas boilers. The HON allows all emission points that have numerical emission standards to participate in an emissions average. Process vents, storage vessels, transfer rack, and wastewater streams are all allowed in the emissions average and they all have differing emission standards. Only equipment leaks, which have no defined allowable emission level, are excluded.

To be clear, CIBO proposes that units sub-categorized as solid or liquid fuel boilers or process heaters on December 23, 2011, and thereafter converted to fire gas 1 fuels, will remain sub-categorized as solid or liquid fuel boilers or process heaters, only for purposes of emissions averaging. While the conversion of a solid or liquid fuel boiler or process heater to gas 1 will not change the unit's sub-categorization for purposes of emissions averaging, the boiler or process heater would be required to comply with work practice standards and other recordkeeping and reporting requirements applicable to gas 1 boilers or process heaters.

EPA's decision to propose work practice standards for gas 1 units is based on its determination that the application of measurement technology to this particular class of sources is not practicable due to technological and economic limitations (*see* §112(h)(2)(B) of the Act). This decision was driven, in part, by the extremely low numerical emission limits that EPA would have proposed if it had made MACT floor determinations. The measurement methods are technically limited such that some of the detection limits are above the numerical standards that would have been applicable. There was also an element of cost as many of the sources in this class of units have no means to obtain a representative sample for the measurement methodologies. Concerns about how to characterize the emissions profile from a converted boiler could be addressed by using a default value equal to three times the detection limit of the reference test method (3xDL) for use in the emissions averaging calculation. This would enable sources to realize the environmental benefits of converting to natural gas (gas 1) without trying to test for pollutants with very low emission rates. However, if an owner/operator determined it to be feasible and desirable, they could alternatively conduct one time emissions testing with the natural gas/other gas 1 fuels to determine actual emission rates and use those if they are above detection levels. Further, as we have stated, such a converted unit would otherwise comply with the requirements for a gas 1 boiler or process heater.

As both the case law and prior EPA precedent demonstrate, EPA has all the latitude it needs under the Clean Air Act to allow emissions averaging across <u>all units</u> at a given facility that are subject to Subpart DDDDD, so long as they have an applicable numeric emission limit. Our suggested revisions would establish the numeric emission limit for an existing solid or liquid fired unit converted to gas 1 based on the emission limit applicable to the unit <u>prior to conversion</u>.

In reality, choosing to convert a solid- or liquid-fired unit to fire natural gas/gas1 fuels is one among many control technologies that a source could evaluate as it seeks to find the most cost-effective approach to comply with the rule. Some member companies have already invested a considerable amount of resources into studying exactly that question: What is the most cost-effective compliance strategy? One member company performed in-depth engineering evaluations of a wide variety of technologies to identify the most rational approach for the simultaneous control of HAPs, SO2 (for the NAAQS), NOx (for ozone season controls), and greenhouse gases from its coal fired units. If that company concluded that co-firing 50% natural gas with 50% coal was the optimal MACT control technology for some of its boilers, EPA would allow that company to average the emissions from those 50/50 units along with the emissions of similar units firing 100% coal. Likewise, if it concluded that co-firing 90% natural gas with 10% coal was the optimal MACT control technology for some of its boilers, EPA would allow it to average the emissions of those 90/10 units with similar units firing 100% coal. It is inconceivable why EPA would not then allow that company to convert a coal unit to fire 100% natural gas and average with similar units firing coal provided that the company demonstrated to its own satisfaction that such co-firing and full conversion approaches are technically feasible and commercially advantaged. Yet EPA's arbitrarily narrow interpretation of emissions averaging stands as the greatest impediment to such a solution.

Converting a solid- or liquid-fired unit to natural gas should be treated by EPA as one among the many control technologies that a source may elect to adopt to comply with the rule. Such a reading would not require that a converted unit be "re-subcategorized"; rather, EPA should only require that the unit use a default three times the detection limit of the applicable reference method (3xDL) for use in emissions averaging calculations to demonstrate its emissions profile (or actual test results if feasible and above detection limits at the owner/operators discretion). This would allow EPA to maintain the integrity of its original Gas 1 subcategory and the legal precedents which resulted in its reasonable conclusion to require work practice standards for units in that subcategory. But it would also allow sources the flexibility to adopt, if the source so chooses, to install a firing system technology to comply with the rule, rather than a back-end equipment technology.

V. TREATMENT OF PROCESS GAS STREAMS DIRECTED TO BOILERS

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

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

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

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

> or other gas 1 fuels are cofired with other fuels and those gaseous fuels are subject to another subpart of this part, **to part 60, or to part 61** you are not required to conduct a fuel analysis of those fuels according to § 63.7521 and Table 6 to this subpart.
>
> §63.7521(f)(2) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for gaseous fuels that are subject to another subpart of this part, **to part 60, or to part 61**."

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

In addition, §63.7510(a)(2)(iii) appears to require mercury fuel analysis for natural gas:

> §63.7510(a)(2)(iii) You are not required to conduct a chlorine fuel analysis for any gaseous fuels. You must still conduct a fuel analysis for mercury on gaseous fuels unless the fuel is exempted in paragraphs (a)(2)(i) through (iii) of this section.

EPA needs to clarify this paragraph to indicate that mercury analysis is also not required for natural gas or refinery gas.

VI. NATURAL GAS CURTAILMENT

CIBO commented on EPA's earlier definition of natural gas curtailment and explained its legal and factual deficiencies. In response to comments and in the Proposed Reconsidered rule, EPA did not address the critical compliance obstacle that this definition creates.

EPA's Proposed Reconsideration makes these amendments to the definition in the Final March 2011 Rule of period of natural gas curtailment:

> Period of gas curtailment or supply interruption means a period of time during which the supply of ~~natural gas~~gaseous fuel to an affected facility is halted for reasons beyond the control of the facility. The act of entering into a contractual agreement with a supplier of natural gas established for curtailment purposes does not constitute a reason that is under the control of a facility for the purposes of this definition. An increase in the cost or unit price of natural gas due to normal market fluctuations not during periods of supplier delivery restriction does not constitute a period of natural gas curtailment or supply interruption. On-site gaseous fuel system emergencies or equipment failures may qualify as periods of supply interruption when the emergency or failure is beyond the control of the facility.

76 Fed. Reg. 80653 (redline edits indicate changes to the Final Rule). EPA's revisions on reconsideration do not address the significant concerns raised by sources. This definition continues to present a major compliance concern for industry because the term "halted" is too restrictive and may be interpreted to interfere with existing contractual obligations. The bottom line for sources is that under this narrow definition of curtailment, ordinary gas supply

circumstances will result in Gas 1 sources being re-defined out of the Gas 1 category, if they make sensible market-based decisions regarding fuel availability and pricing impacts.

This definition is apparently written to protect firms whose supply is downstream of a Local Distribution Company (LDC). Users downstream of a LDC can indeed have their supply restricted or halted when the needs of users exceed the LDC's available supply. In such a scenario, residential users, hospitals and others would be given priority and an industrial company would be shut off. In that simple case, the industrial source must burn its alternate fuel. However, most curtailments are not that simple, and instead reflect complex supply and demand circumstances that EPA does not account for in its simplistic approach to curtailments.

The proposed definition does not address the range of gas supply arrangements and would likely create confusion and eliminate routine cost-effective use of gas purchase contract arrangements. Such impacts would extend beyond EPA authority and implicate state and FERC regulatory authority. The range of gas supply arrangements can include purchase from an LDC under state jurisdiction or purchase from a gas supplier that transports the supply on a interstate/intrastate gas pipeline system under FERC jurisdiction. Purchased transportation can be firm (a consumer contracts for a specific amount of transport capacity) or interruptible (a consumer can be interrupted by the transporting entity at the transporting entity's will), or a combination of firm and interruptible. Because a site must pay a cost for firm transportation whether the gas is actually purchased or not, many large natural gas consumers utilize contracts that incorporate a combination of firm and interruptible supply contracts to optimize transportation costs in light of variation in natural gas demand.

Normally, with purchase of firm transportation, the risk of curtailment limits a firm's delivery amount to the firm transport capacity purchased (or the firm's daily nomination, whichever is less). Curtailment typically occurs when demand is unusually high, for example, with very cold weather.

Firm transport customers are normally only subject to curtailment to less than their firm capacity when the transporter suffers a force majeure situation (e.g., a compressor station failure, pipe failure), or the supply is significantly disrupted (e.g. a major hurricane in the Gulf of Mexico).

In the case of interstate/intrastate gas transportation contracts, there are provisions under which a customer hypothetically could buy natural gas in excess of its contractual firm transportation amount during a curtailment. However, penalties in pipeline tariff agreements, regulated by FERC, can be significant and are intended to make the a violation of curtailment so painful as effectively to prohibit a consumer from attempting to defy the curtailment order. As examples, one interstate pipeline tariff cites a $15 per Dekatherm penalty on top of Henry Hub prices, effectively quadrupling the cost of natural gas and another interruptible user reports an even higher $30 per Dekatherm penalty. The penalties of unauthorized natural gas usage during a curtailment are imposed to ensure pipeline system integrity and are not considered a unit cost increase for the price of natural gas. In contrast, for firms purchasing gas from a LDC there is little or no ability to buy supply as customers are required to honor the curtailment order. If they do not, the customer is subject to huge penalties for amounts taken above the contract quantity and pipeline system integrity can be compromised.

For interruptible service, or for that portion of a supply contract that is interruptible, transportation of natural gas on both interstate/intrastate pipelines and local distribution systems would be “halted” or “restricted” under Operational Flow Order (OFO) conditions (or pre-OFO conditions). Because many large consumers of natural gas utilize contracts that combine firm and interruptible transportation, an OFO represents an unpredictable constraint on a firm’s ability to operate its plant at optimal levels. For those firms whose natural gas supply contracts consist entirely of firm delivery, this would be an infrequent event such as a Force Majeure. Many small manufacturing sites such as those subject to GACT also operate under purely interruptible service contracts. Frequency of curtailment under an OFO varies but on system’s that are supply/capacity limited curtailment may run from zero to multiple events per year based on actual overall supply/distribution capacity versus actual overall demand.

In certain regions of the country, firm service contracts are no longer available and interruptible service is the only option for small manufacturing sites. When disparity between overall supply and overall demand threatens the integrity of the pipeline supply system, interruptible supply contracts are curtailed generally by Operational Flow Orders (or similar contractual requirements by another name) issued to users under their supply contract terms. These orders do not generally involve physically blocking the supply pipeline[14], but rather an evaluation after the fact of possible non-contractually compliant use during the curtailment period and the institution of a fine or penalty that can be assessed as high as 10 or so times the contract gas sales price. Payment of a penalty due to unauthorized natural gas usage during an OFO is not considered an increase in the cost or unit price of natural gas or a surcharge due to market supply/demand fluctuations. The contracts and user requirements are to protect the physical integrity of the system and allow its operation in compliance with FERC or state regulations.

Example contract language from actual contracts for supply reinforce these points and should be helpful in understanding curtailment scenarios.[15]

The current definition could be interpreted to mean that if a company contracts for interruptible natural gas supply, where the interruption could either mean the supply is halted by the utility/FERC regulated pipeline or the facility must switch fuels to avoid contractual fines, the

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[14] More drastic response such as blocking service lines generally is not considered unless more drastic curtailment situations warrant. This is not typical practice in the experience of many small manufacturers. In limited supply areas, Operational Flow Order restrictions and curtailment may happen multiple times a year for interruptible supply users. In some regions even this level of curtailment is infrequent.

[15] Examples of gas supply contract language: Curtailment “- a critical period in which natural gas transportation service provider issues an Operational Flow Order (OFO). The OFO is required to prevent physical damage to or to maintain the integrity and safe operations of the provider’s natural gas pipeline system. ***If a penalty for ignoring an OFO is assessed***…… The payment or increase in cost or unit price of natural gas for unauthorized gas usage during an OFO shall under no circumstances be considered as giving the buyer the right to violate OFOs nor shall such payment be considered a substitute for any other supply remedy available. This increase in cost or unit price of natural gas is not considered a surcharge.” Moreover, helpful websites include: http://www.ferc.gov/industries/gas/gen-info.asp - FERC website on natural gas regulations http://www.ingaa.org/cms/143.aspx - Link explaining how natural gas pipelines are regulated.

use of backup liquid fuel during periods of high residential/critical infrastructure demand would not constitute curtailment unless the utility/FERC regulated pipeline actually physically halts the entire supply of gas to the facility.

Most LDC's/FERC regulated pipelines do not have automatic shutoff capability, but rather they rely on customers taking appropriate action to reduce gas use when needed for meeting high demand or for system integrity requirements. Therefore, due to the inclusion of the word "halted" in the current definition, we are concerned that the only conditions that would meet the definition are those where the gas supply to the facility is completely stopped beyond the control of the facility. Contracts for interruptible service and the inaccessibility of firm service in some regions leave a user only a limited choice – "either use backup liquid fuel during periods of natural gas curtailment, manufacturing operations cease or violate contractual restrictions under strict penalties".

If the definition of curtailment is not revised to include contractual orders whose supply is halted or restricted due to an OFO (Operational Flow Order), interruptible supply users have but no option other than to cease operations during periods of gas curtailment and suffer the economic consequences. If that is EPA's intent, the extremely high cost to manufacturers from this result has not been assessed. Such a cost impact would have severe effects on the US economy, with its harshest effects falling on smaller manufacturers. EPA did and directly affect small It is our belief that such

We request that EPA clarify that the Agency does not intend to restrict the ability of natural gas consumers to obtain the most appropriate gas purchasing arrangement for their purposes, while at the same time complying with FERC or State regulations. In addition, EPA should clarify that EPA will allow use of backup liquid fuel firing under those situations where the supply of natural gas is restricted to affected facilities under a purchase contract arrangement.

The revised text does not account for the many contractual arrangements possible, and the definition should be amended so that it does not restrict the ability of natural gas-fired units to obtain the most appropriate gas purchasing contract arrangement for their purposes. In addition, EPA should revise the text to allow use of backup liquid fuel firing under situations where the supply of natural gas is restricted to affected facilities under a purchase contract arrangement to the extent that a very high cost or penalty would be involved for continued natural gas use at pre-restriction levels.

We suggest the following revisions to the definition in the Proposed Reconsideration Rule:

> "Period of gas curtailment or supply interruption means a period of time during which the supply of gaseous fuel to an affected facility is halted or restricted for reasons beyond the control of the facility~~. The act of entering into~~ or due to the terms of a contractual agreement with a supplier of natural gas ~~established for curtailment purposes does not constitute a reason that is under the control of a facility for the purposes of this definition.~~that allows gas curtailment or supply interruption or due to the terms and conditions of a tariff or supply rate offered by the local utility provider that allows curtailment or supply interruption. Restriction of supply by a natural gas supplier under a contractual order (e.g.,

operational flow order under an interruptible supply contract) does constitute a period of natural gas curtailment or supply interruption. An increase in the cost or unit price of natural gas due to normal market fluctuations ~~not~~that does not occur during periods of supplier delivery restriction does not constitute a period of natural gas curtailment or supply interruption. On-site gaseous fuel system emergencies or equipment failures ~~may~~ also qualify as periods of supply interruption when the emergency or failure is beyond the control of the facility."

VII. MONITORING AND COMPLIANCE

A. O2 Monitoring

In the Final Boiler MACT Rule, EPA required continuous oxygen monitoring for boilers subject to CO numeric emission limits. 76 Fed. Reg. 15,671-73. (2011 Final Rule). EPA finalized this approach as an alternative to requiring the use of CO CEMS. While EPA maintained this approach in the 2012 Reconsidered Boiler MACT Rule, EPA did modify the rule to provide more flexibility. EPA's oxygen monitoring approach and decision to increase flexibility is appropriate, however additional clarification is needed.

EPA concluded that, instead of requiring monitoring of oxygen levels in the stack, "a better way to ensure good combustion is by requiring the installation, calibration, monitoring and use of oxygen trim systems to optimize air to fuel ratio and combustion efficiency." 76 Fed. Reg. 80,609. (2012 Reconsidered Boiler MACT Rule). EPA reasoned that "the data from such devices is not only an appropriate control for efficient combustion and a less burdensome alternative to monitoring stack oxygen concentration but also is a better system for many types of units that experience significant load swings and operate with high levels of excess air." 76 Fed. Reg. 80,609. (2012 Reconsidered Boiler MACT Rule). As set forth in comments CIBO's Petition for Reconsideration of the Final Boiler MACT Rule, EPA's proposed oxygen monitoring requirements are appropriate and the EPA was justified in increasing the flexibility.

1. The change from O2 CEMS to O2 trim is appropriate and supportable, but O2 trim system clarifications are required.

In the March 21, 2011 final rule, EPA included continuous oxygen monitoring as the compliance method for sources with a CO limit, instead of mandating the use of CO CEMS. EPA now proposes to amend the oxygen monitoring requirements (76 FR 80609, Dec. 23, 2011) to allow for the use of continuous oxygen trim analyzer systems instead of oxygen CEMS. EPA is also removing the requirement that the oxygen monitor be located at the outlet of the boiler, so that it can be located either within the combustion zone or at the outlet as a flue gas oxygen monitor. We support EPA's proposal to add flexibility and reduce the cost and burden of the continuous oxygen monitoring requirements, as these changes allow facilities to utilize existing oxygen trim systems rather than installing CEMS.

Many existing boilers already utilize flue gas oxygen analyzers for indication, alarm, and O_2 trim control, where the fuel/air ratio is automatically controlled for optimum combustion conditions. The sensing location for existing O_2 monitors is typically in the optimum location to sense flue gas composition as reliably as possible, because sensing of oxygen in these cases maintains proper excess air levels and helps prevent unsafe operating conditions. For many types of combustion units, that location is near the boiler furnace outlet in a position upstream of any potential air inleakage points to avoid erroneous excess air indications which would drive controls in an erroneous direction. This location is also upstream of air preheaters where utilized, thus avoiding the erroneous (high O_2) indications due to inherent leakage across regenerative air preheater seals or potential tube leakage in recuperative air preheaters. For those units equipped with existing O_2 sensors and O_2 trim control systems, flue gas composition at those locations would already be used for combustion tuning and control characterization. Therefore, if O_2 monitoring is desired for continuous compliance under the Boiler MACT rule, sensing O_2 at that current location would be logical and proper from a technical perspective.

However, CIBO recommends the following changes to the regulatory language so that clarity is provided and operability is not negatively impacted. These clarifications are discussed below:

Oxygen sensing location

The Oxygen analyzer system is defined in §63.7575 in part as follows:

> *Oxygen analyzer system means all equipment required to determine the oxygen content of a gas stream and used to monitor oxygen in the boiler flue gas or firebox.*

The optimum location of the sensor or sampling point is dependent on the specific boiler design. In different applications, that location might be at the furnace exit, in the convection pass, at the boiler outlet, or at another downstream location. We recommend that this language be modified as follows to allow latitude in the exact location of the sensing point:

> *Oxygen analyzer system means all equipment required to determine the oxygen content of a gas stream and used to monitor oxygen in the boiler or process heater flue gas, boiler/process heater ~~or~~ firebox, or other appropriate intermediate location.*

Oxygen trim system set point

Paragraph 63.7525(a)(2) states:

> *"You must operate the oxygen trim system with the oxygen level set at the minimum percent oxygen by volume that is established as the operating limit for oxygen according to Table 4 to this subpart."*

First, we believe this paragraph should reference Table 7, not Table 4, since that is the table with the requirements for establishing operating limits. Second, the wording of §63.7525(a)(2) above is more restrictive than the wording in Table 8, item 9 (c) as shown below:

> *"Maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen level measured during the most recent carbon monoxide performance test."*

The Table 8 language allows operation with the 30-day rolling average oxygen level at or above (no lower than) the lowest 1-hour average oxygen level measured in the most recent performance test whereas the §63.7525(a)(2) wording requires continuous operation at the minimum oxygen percent established during the prior test. Innate boiler operating characteristics require operation with higher excess air (higher oxygen) at lower operating rates simply due to lower fuel and air velocities, degraded mixing of fuel and air as those flow rates decrease, and lower furnace temperatures. Therefore, it is necessary for the actual oxygen trim system set point to vary over load, with the lowest set point typically occurring at or near full load operation. The Table 8 language accommodates this operating requirement and Table 4 and §63.7525(a)(2) need to be revised to provide similar operating latitude.

In addition, solid or liquid fuel fired boilers and process heaters subject to the CO limits in this rule may also be equipped to fire other liquid or gas fuels that may be able to allow the unit to operate at lower oxygen levels for improved boiler efficiency. Alternatively, they may also fire biomass or other traditional fuels that require higher excess air for improved combustion. Operators may also need to modify the oxygen setpoint or trim system to accommodate boiler or fuel quality issues. EPA needs to recognize that oxygen trim systems not only provide a means for energy efficiency, but they also are integral to furnace combustion control and furnace safety. While use of a 30-day rolling average does provide some operating latitude, this rule should not needlessly restrict operator latitude relative to safety or operating efficiency. The real value for operations is to have an indication of excess oxygen available to operators, along with appropriate alarms so that corrective actions can be taken in a timely manner. Therefore, considering all of the above, it is recommended that the paragraph 63.7525(a)(2) wording be revised to read as follows (suggested inserts in italics):

> *(2)* You must operate the oxygen analyzer ***and trim*** system with the oxygen level set at ***or above*** the minimum percent oxygen by volume that is established as the operating limit for oxygen according to Table 7 to this subpart ***when firing the fuel or fuel mixture utilized during the most recent CO performance stack test. Operation of oxygen trim control systems to meet these requirements shall not be done in a manner which compromises furnace safety.***

B. SO2 CEMS for HCl compliance

In the 2012 Reconsidered Boiler MACT Rule, EPA is soliciting comment on "the use of SO2 CEMS for demonstrating continuous compliance with the HCl emission limits." 76 Fed. Reg. 80610. EPA has indicated that it is a "reasonable approach" to allow the use of SO2 CEMS to demonstrate compliance with the HCl standard if there is a "correlation between SO2 control and control of other acid gases emitted from each specific unit that chooses to use SO2 CEMS." 76 Fed. Reg. 80610. As stated in our comments on the Proposed Boiler MACT Rule, SO2 CEMS is a good indicator of HCl removal and EPA should allow its use in demonstrating compliance with the HCl standard.

A proposed approach to the use of SO2 CEMS for demonstration of continuous compliance with the HCl limit is to determine the SO2 emission rate (in lb/MMBTU) at the time of the HCl stack test for Boiler MACT compliance. Compliance with SO2 emission rate determined during the HCl stack test is proposed to be calculated on a 30-day rolling average.

1. Continuous compliance with HCl limit by scaling sorbent injection rate at time of test is unworkable.

In the Final Boiler MACT Rule, EPA required continuous monitoring of sorbent injection for continuous compliance purposes. 76 Fed. Reg. 15,615. In addition to the comment below, CIBO asks that EPA confirm that the use of limestone for SO2 control in a CFB is a form of sorbent injection and could be included in this compliance strategy. As stated in our comments on the Proposed Boiler MACT Rule, which were filed on August 20, 2010, monitoring sorbent injection rates is problematic and unreasonable. Although the reproposed rule improved on the proposed Boiler MACT by allowing scaling of injection rate to account for load changes, in some applications this linearization of a system that is not linear in nature causes not only a potentially large amount of sorbent to be wasted but in the case of the CFB utilizing limestone in the furnace for SO2 control, will cause operational issue for the boiler itself. CIBO suggests that alternative methodologies be considered, such as tracking of the calcium to sulfur ratio of the fuel and the sorbent. This approach allows the source to more closely tune the sorbent injection to the fuel quality and is based upon the presumption that So2 control correlates to HCl control.

2. EPA's claims for SO2 removal co-benefits are grossly exaggerated.

EPA states that the presumed technology for controlling acid gases, Duct Sorbent Injection (DSI), will achieve significant control of SO_2 simultaneously to the control of HCl. EPA further states that reduction in HCl will produce a co-beneficial reduction in SO_2 of 558,400 tons per year from existing sources. This reduction is based on EPA's assumptions of an overall HCl removal efficiency of 71% and corresponding overall SO_2 reduction of 57%. EPA did not address the co-beneficial removal of SO_2 relationship in this rule, but did address the technology basis in the preamble to the Utility MACT (MATS) rule (pp. 592-602). In that discussion, EPA references multiple sources to support its application of DSI as a reasonable approach to control of HCl. Unfortunately, EPA's citations present a biased and incomplete view of the technology's efficacy for SO_2 removal.

First, EPA cites the BART analysis submitted for Dominion Energy's Kincaid Power Plant (http://www.epa/state/il.us/air/drafts/regional-haze/bart-kincaid.pdf). The source concludes on that DSI with Trona would achieve approximately 60% SO_2 reduction on a 30-day rolling average basis. On its surface, this would appear to support EPA's assumptions for SO_2 removal efficiency for industrial boilers. However, the SO_2 removal efficiency expected at Dominion's Kincaid Power Plant is based on the assumption that the unit will fire PRB coal with 0.3% sulfur. Because most industrial coal fired units use bituminous coals which have sulfur and chlorine contents several times higher than PRB coals, it is impossible to extrapolate any conclusions from a PRB unit to units firing bituminous coals. This BART analysis serves merely to demonstrate what one power plant with one variety of coal can achieve, but fails as a predictive tool for units firing other types of fuels.

Second, EPA cites literature published by Babcock and Wilcox, an OEM with deep experience in coal-fired power generation and the installation and retrofit of advanced emission controls. In PS-451 (http://www.babcock.com/library/pdf/ps-451.pdf), Babcock and Wilcox holds that Dry Sorbent Injection systems can provide "up to 80 percent SO_2 removal efficiency," which again appears to support EPA's general approach to estimating SO_2 co-benefits. However, that same document also states that in a typical DSI application, an "oversized electrostatic precipitator or new baghouse [is] required." Very few industrial units have the luxury of oversized particulate collectors, which calls into question whether a more typical unit with a correctly-sized or under-sized particulate collector would be able to achieve high rates of SO_2 removal efficiency. In short, this paper confirms that high co-benefits are possible, but it fails to provide a predictive tool to evaluate the probability or extent of those co-benefits.

A further review of Babcock and Wilcox's published literature on DSI reveals helpful additional information correlating the technology's removal efficiency of HCl with SO_2. In BR-1851 (http://www.babcock.com/library/pdf/BR-1851.pdf), figure 3 shows simultaneous removal efficiencies of both HCl and SO_2 for a pilot unit configured with a pulse jet fabric filter (PJFF) firing bituminous coal. Using EPA's metric of approximately 70% HCl removal as the benchmark, a curve fitting analysis shows that the OEM's own data predicts a 30% SO_2 removal efficiency, or less than half what EPA's assumes when it calculates co-benefits.

Babcock and Wilcox also gives valuable insight into the significant variability of predicting SO_2 co-benefits in its BR-1866 (http://www.babcock.com/library/pdf/BR-1866.pdf). In that paper, figure 11 shows how SO_2 removal efficiency is highly dependent upon the selection of reagent. EPA rightly assumes that most sources will adopt the most cost-effective approach to controlling acid gases, which in many cases would be Trona. However, curve fitting analysis of figure 11 shows that while achieving EPA's benchmark of 57% SO_2 removal efficiency can be achieved with relatively low normalized stoichiometric ratios using Milled Sodium Bicarbonate, achieving that same level of SO_2 removal efficiency requires substantially more reagent if Milled Trona or Trona is used instead. Sources will optimize their DSI systems to control HCl, and both EPA and the OEM's acknowledge that DSI systems will preferentially treat HCl before SO_2. Thus, when a source optimizes a DSI system to satisfy the HCl requirement of this rule, it will be using significantly less reagent than required to achieve aggeressive SO_2 removal efficiency. It is evident that EPA's assumptions for SO_2 co-benefits are optimistic, rather than realistic.

EPA references results published by another long-established OEM (United Conveyor Corporation) in its preamble to the Utility MACT (MATS) on page 597 (http://unitedconveyor.com/uploadedFiles/Systems/Systems_Sub/McIlvaine%20Multipollutant%20Removal%20Oct%202011.pdf). That reference shows that the SO_2 removal efficiency can vary between 30% and 70% for a HCl removal efficiency over 90% when firing eastern bituminous coal. With such a broad range of possible SO_2 removal efficiencies, it is clear that predicting a single representative value for the co-benefit is extremely challenging. EPA also describes the pilot testing of fine-milled trona at EERC's pilot facility in the preamble on page 596, stating that "fine-milled trona . . . provides 90 percent HCl removal at a SO_2 removal rate of less than 20 percent....” This comment was intended to demonstrate the selectivity of trona to target HCl rather than SO_2, but it serves to illustrate that not only is EPA’s assumption of 57% SO_2 removal unrealistic, but also that EPA was aware of data that showed much smaller co-benefits than it claimed in its analysis of the benefits of the rule.

These conclusions are supported by other sources as well. Notably, Solvay Chemicals reports data substantially less optimistic than EPA’s assumptions for SO_2 removal co-benefits. The slide deck by Solvay in the docket includes, on Slide 13, test data showing the simultaneous control of HCl and SO_2 compared to the total stoichiometric ratio. In this test, Solvay shows that while substantial SO_2 removal is technically achievable, approximately 35% SO_2 removal efficiency would be expected if the source controlled HCl removal efficiency to approximately 80%. In Solvay’s whitepaper http://www.powermag.com/whitepapers/dry_sorbent_injection_with_trona_or_sodium_bicarbonate/dl/, Figure 7 predicts that when 80% HCl removal efficiency is achieved, the simultaneous SO_2 removal efficiency would be between 10% and 25%. All of these results cast doubt on the amount of credit EPA takes in its analysis of co-benefits.

Taken together, the balance of published knowledge strongly indicates that EPA’s assumptions when calculating co-benefits due to SO_2 removal is grossly optimistic:

Source	HCl Removal Efficiency	Co-beneficial SO2 Removal Efficiency
EPA: MACT for Major Sources	71%	57%
EPA: MATS Preamble, EERC Pilot Testing	90%	20%
Babcock and Wilcox: BR-1851	~ 70%	~ 30%
United Conveyor Corporation: Multipollutant Removal	~ 70%	30% – 70%
Solvay Chemicals: Whitepaper	~ 80%	10% - 25%

CIBO agrees that some SO_2 removal co-benefit will occur with DSI systems installed to control HCl. However, experience shows that the amount of co-benefit will depend on the type of fuel being fired (e.g. bituminous, PRB, oil, etc.), the concentration of chlorine and sulfur in a given units particular fuel, the reagent selected (trona, milled trona, sodium bicarbonate, etc.), the temperature and residence time available for the reagent to react with the HCl and SO_2, and the particulate collector type and size. These variables mean the actual co-benefit will be highly site specific. Based on a review of published results (summarized in the table above), it is clear that EPA has overstated the co-beneficial removal of SO_2 by at least a factor of two, and perhaps as much as a factor of five or six. EPA’s total claimed monetized benefit of $27 billion to $67 billion, of which $25 billion to $65 billion is due to the co-beneficial removal of SO_2 rather than the control of HAPs, should be reduced commensurately. Reducing the co-benefit attributable to

SO_2 by a factor of between two and six would produce a more realistic monetized benefit of between $4 billion and $33 billion.

C. Alternative for HCl and Hg CEMS

EPA has proposed to allow HCl and Hg CEMS as an alternate to complying with fuel analysis or stack testing and continuous parameter monitoring. 76 Fed. Reg. 80,610. CIBO members support the flexibility provided by this option, as facilities that have these monitors installed should be able to take advantage of their use in order to comply with this rule and should not be required to perform additional stack testing or parameter monitoring. As mentioned above, and for the reasons set forth in prior comments, emissions averaging with no 10% penalty should be allowed if CEMS are used.

In addition, we support EPA's decision not to require Hg CEMS on industrial boilers and process heaters. This support is based on the findings of a study carried out by the International Paper Company and NCASI on a biomass boiler that was co-firing coal at the time of the study and was equipped with a wet scrubber for PM control. The results of the study showed that the response of the Hg CEMS could not be correlated with the EPA Method 29-measured mercury concentrations in the stack gas. NCASI is preparing a detailed report on this study which will be submitted to EPA.

VIII. PARAMETRIC MONITORING PROVISIONS FO ADDITIONAL CONTROL DEVICE TYPES

Parametric monitoring provisions are needed for acid gas controls including dry sorbent injection. Also, an option to use SO2 emission rate and a SO2 continuous monitoring system correlated to HCl emissions is needed. On page 80464 of the reconsideration proposal preamble, EPA, in response to Petitioners' requests, is soliciting comment on the need to specify monitoring provisions for dry sorbent injection and any other control devices not already addressed.

Dry sorbent injection or spray dryer absorbers (using hydrated lime) are two technologies that could be used to reduce HCl and/or SO2 emissions. We suggest a similar approach as in the Boiler MACT – see Table 7 on page 80668 of the December 23, 2011 Federal Register.

We take this opportunity to also request an alternative CPMS utilizing SO2 continuous monitoring. On page 80610 of the reconsideration proposal for the Boiler MACT, EPA solicits comment on petitioners' request to allow use of SO2 CEMS for demonstration of continuous compliance with the HCl emission limits for sources that are equipped with acid gas controls:

> While the EPA does not have enough information to propose specific requirements, we believe that a reasonable approach would be to allow for the use of SO2 CEMS provided that the source demonstrates a correlation between SO2 control and control of other acid gases emitted from each specific unit that chooses to use SO2 CEMS. Such a relationship is expected because the available add-on controls for acid gases would provide better control efficiencies for the acid gas HAP than for SO2, and, therefore, demonstration of SO2 control using

> CEMS would provide assurance that the acid gas HAP are being controlled. Therefore, the EPA is soliciting comment on the use of SO2 CEMS for demonstrating continuous compliance with the HCl emission limits with the condition noted above.

We agree with EPA's conclusions that acid gas HAP control efficiencies would be better than SO2 control efficiency (for a given acid gas control device) and that it should be possible to demonstrate a correlation between the two control efficiencies and then to rely on an SO2 CEMS to demonstrate continuous compliance. EPA drew this same conclusion in the recently finalized Utility MACT and set alternative SO2 emission limits.

In this case, we agree there is not enough information to set an alternative SO2 limit that correlates with the HCl emission standard, such as was done in Utility MATS. One key difference is that the Utility MATS HCl emission limit (0.002 lb/mmBtu) is about ten times lower than the proposed Boiler MACT HCl limit for solid-fuel boilers (0.022 lb/mmBtu).

We would suggest in both the Boiler MACT and the CISWI rule that SO2 continuous monitoring be allowed as a continuous parametric monitoring system (CPMS) and that the maximum 30 day rolling average SO2 operating parameter limit to be set during a 3-run performance test where HCl emissions are demonstrated to comply with the final HCl emission limit. This method of continuous compliance should be allowed on any unit that utilizes an acid-gas control technology including wet scrubber, dry scrubbers, and duct sorbent injection.

If this option is incorporated into the final rule, we request that the SO2 CEMS be allowed to select either Part 60 or Part 75 for compliance procedures as many of the existing SO2 CEMS already use Part 75 quality assurance procedures.

A. CO CEMS MACT

In the Reconsidered Boiler MACT Rule, EPA has solicited comments on a variety of topics related to the CO CEMS-Based Alternative Emission Limits and Monitoring. EPA has requested comment on the most appropriate averaging time, the length of rolling period to use when calculating the CO CEMS MACT floors, the approach used to calculate the UPL based MACT floors, the ranking methodology which should be used, and whether it was appropriate for EPA to adjust the limit in certain circumstances to reflect the actual level that was demonstrated to be achieved at all times by those units. 76 Fed. Reg. 80,611-613.

EPA has proposed an "Alternate MACT Floor Calculation Methodology" where the highest maximum 10-day rolling average from the top half of the best performers for each subcategory was selected as a MACT floor option. Setting an alternative standard for data collected using CEMS is necessary because MACT floors must be "achieved by the best performers at all times, even during large CO swings." EPA's current approach would eliminate the possibility of a boiler in the best performing floor being in violation of the CEMS-based limit. Nothing in the CAA prohibits EPA from establishing alternative requirements for data gathered using CEMS. In fact, CAA § 112(d) provides EPA with broad authority to "distinguish among classes, types, and sizes of sources within a category or subcategory in establishing such standards." Boilers with CEMS are easily distinguishable from those that do not have CEMS.

EPA is currently proposing a 10-day averaging period. CIBO is aware that additional data will be submitted and that EPA will be justified in proposing longer averaging times. It would be appropriate for EPA to establish the longest averaging period that can be justified by the available data.

Based on the information contained in the 2011 Reconsidered BMACT Rule, it is not clear how the 10-day rolling average for the CO CEMS limit is calculated. EPA needs to clarify that valid data excludes hours during startup and shutdown and unit down time. EPA should specify the minimum number of readings, which will assure that the 10-day average concept is not undermined in cases of long outages.

B. PM CEMS/CPMS

PM CEMS have not been demonstrated for use on biomass or on other installations where fuel type, production rate or other characteristics of the emissions are changing. CIBO appreciates the fact that EPA recognizes that PM CEMS cannot effectively be used to measure particulate emissions accurately. However, EPA is proposing use of this instrument as a PM CPMS. However, for the same reasons that a PM CEMS is not practical for use in measuring PM, the PM CPMS will not provide any meaningful correlation to emissions or control device effectiveness and therefore is a technically inappropriate choice. In addition to the fact that a PM CPMS will not correlate with emissions and cannot be used effectively in a PM CPMS, it is much more costly than devices that can perform the same function. Thus, EPA must abandon its proposal to require PM CEMS technology for a PM CPMS.

1. Boiler size clarification

CIBO asks EPA to confirm that the boiler size threshold for determination of whether or not a PM CPMS must be installed is the average annual heat input, i.e., annual heat input divided by the number of actual operating hours in the year. Similar to the Utility MACT, CIBO suggests that this value be determined using three consecutive years beginning after the compliance date to determine average annual heat input.

2. CPMS are not necessary

In the proposed Reconsidered Rule, PM CPMS has replaced the requirement of a PM CEMS. CPMS is not optional for sources >250 MMbtu. Although EPA altered the monitoring requirement, it is still onerous and not necessary to demonstrate compliance. The CPMS equipment is the same as the prior CEMS requirement, which is a major capital installation not justified by any additional environmental or compliance benefit beyond other PM monitoring systems.

The PM limits for solid fuel boilers range from 0.028 lbs/mmbtu for stoker boilers to 0.088 lbs/mmbtu for fluidized bed boilers. Almost all fluidized bed boilers in the country have been permitted since the effective date of the 40 CFR Part 60 Subpart Db NSPS and will have allowable limits for PM no higher than 0.05 lbs/mmbtu. Also, since most new solid fuel boilers would also have been permitted under PSD or non-attainment NSR, their allowable limits are likely more in the range of 0.02 – 0.03 lbs/mmbtu. As such, COMs supplemented with bag leak detectors and pressure drop monitoring are perfectly adequate to prevent any exceedance of the existing allowable standards much less, the 0.088 lbs/mmbtu proposed for the MACT. The addition of a CPMS will be a needless expense and will offer no benefit. Likewise, stoker and PC boilers can be, and are in practice, adequately monitored by COMs and parametric monitoring.

3. PM CEMS have not been demonstrated on biomass-fired boilers or units that operate with variable fuel types and production loads.

PM CEMS have been demonstrated in practice on coal-fired utility boilers and at least one coal-fired industrial boiler. They have not been demonstrated on biomass-burning boilers. A review of all the types of PM CEMs and potential suitability for use on biomass-fired boilers is problematic for a number of reasons.

PM CEMS do not measure mass. Because PM monitors do not measure mass directly, they must be calibrated against some manual, PM reference method measurement procedure like EPA Methods 5, 5i or 17. The fundamental problem arises when the characteristics of the emitted PM exhibit significant variability and this variability in the particulate properties translates into a shift or alteration in the instrument's calibration curve.

Biomass, as well as CISWI units, which combust a mixture of fuels and which operate at variable loadings pose significant challenges in establishing meaningful correlations. In order to establish a calibration curve, one needs to source test the emissions from the stack and correlate those to specific instrument readings.

As fuel and fuel mixes vary, particle size distributions generated vary significantly. Biomass combustion emission distributions are characterized by a bimodal particulate distribution.[16]

[16] "BIO-AEROSOLS – Aerosols in Fixed Bed Biomass Combustion," Presented by Professor Ingewald Oberberger, Ph.D., Graz University of Technology, Budapest, October 2003.

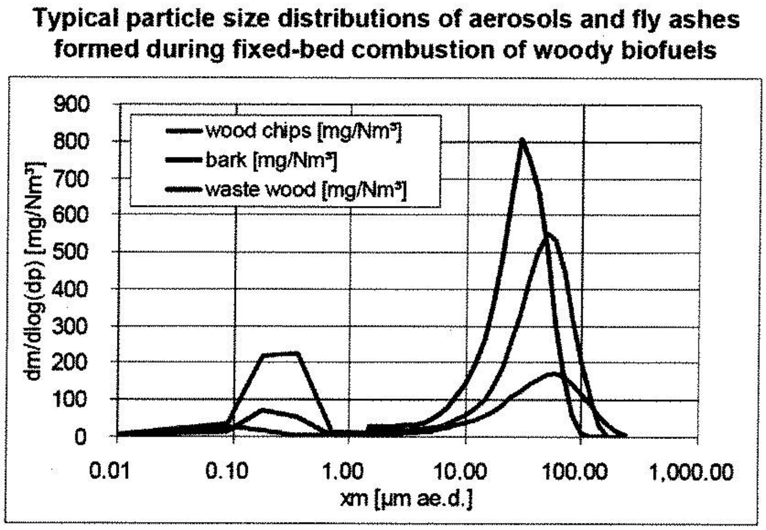

Figure 1. Typical Biomass Fly Ash Particle Size Distribution[4]
Note: Fly-ash means products of combustion

This is due to the vaporization of volatile ash species in the wood-like potassium and sodium biomass ash that yields a bimodal characteristic with peaks of nominally 0.5 and 20 to 40 microns. Coal ash, on the other hand, tends to exhibit a more mono modal distribution without the submicron peak. Data available for PM CEMs effective is primarily limited to coal, and data on how PM CEMS will respond to monitoring biomass emissions is expected to be problematic.

In addition to the variability of the fuels and fuel mixtures the operating load (firing rate) of the boiler will produce varying particulate loading which will challenge the robustness of any PM CEM correlation and calibration. This has been demonstrated during a study conducted by the Electric Power Research Institute (EPRI) of PM CEMS. The results of the study indicate that when inlet loading to ESP's are changed due to different fuel mixtures, the exhaust emissions have a different particle size and distributions. Therefore, a single or even a few correlation curves cannot be used to provide representative compliance correlations over an extensive range of fuels, fuel mixtures and loads. The results of the EPRI Study indicate that when a protocol is developed to simulate varying particle sizes and loads it results in inaccurate mass emissions estimates[17].

For units such as biomass units, which may use a variety of biomass materials and vary production, or for CISWI units, which combust a varying mixture of materials, testing every possible fuel mixture to develop calibration curves for each is infeasible, given the extensive range of possible fuel mixtures.

In practice, changing the fuel mix for the purpose of correlation testing may alter the loadings; however, it would be difficult to do in a systematic way, and in order to gather the reference data needed to develop an acceptable correlation. Thus, for variable fuel and production rate units with variable emission characteristics in the stack where the PM CEMs is being used as a

[17] The Varying Load Simulations in the EPRI study consisted of turning off fields in the ESP

monitor, we conclude that establishing meaningful curves, figuring out how to match those to the fuel and production mixes and finally correlating these with emissions in any meaningful way is impractical. Basically, for each fuel mix that may be used, one would need to be able to establish a correlation curve. Then, the instrument would need to use the right calibration curve for the proper fuel mixture in order for any meaningful correlation with particulate to be established. This solution is not technically feasible.

Beyond this, there are a number of correlation issues. For instance, the PM response to the light scattering instruments are very dependent on particle size, shape and even color. Other technologies have other limitations.

4. PM CPMS based on PM CEMS technology will not produce meaningful results.

For the same reasons that it is not feasible to develop a meaningful correlation between the emissions being monitored by the PM CEMS instrument and particulate emissions in the stack, using the PM CEMS instrument technology as a PM CPMS will produce no repeatable and no meaningful results in situations where the characteristics of the stack emissions change due to changes in fuel mixtures, production rates and instrument correlation issues.

The output from a PM CPMS based on a PM CEMS instrument will simply be meaningless. Any time the fuel mixture changes, the instrument will go out of range even with no change to control device effectiveness or any meaningful change to emissions. This means that requiring use of a PM CPMS would be a very expensive waste of capital resources and would send both the regulated industry and the regulatory agencies on meaningless goose chases. Put quite simply, this technology will not work for its intended purposes.

5. Other cost effective methods ensure control technology is operating as designed.

PM CEMS are not technically effective across a range of conditions as discussed above and are a very expensive method for achieving EPA's objective of assuring ongoing compliance with Boiler MACT and CISWI requirements. Costs[18] for the light scattering PM CEMS, which is lower operating and maintenance costs vs the Beta Attenuation technology was estimated by EPA contractor data to cost between $103,000 to 133,000 in 2004, with substantial annual operating costs as shown below:

[18] **Status of Particulate Matter Continuous Emission Monitoring Systems for Application to Electric Utility Steam Generating Units,** Prepared for:

Emission Standards Division Office of Air Quality Planning and Standards U.S. Environmental Protection Agency, September 7, 2004

Table 3. Approximate Costs for Light Scattering PM CEMS [a]

	Cost Component	Cost	Total Cost
Initial Costs	Planning	$3,600	
	Select equipment	$10,400	
	Provide support facilities	$1,000 to $8,200	
	Purchase CEMS	$36,300 to $47,500	
	Install and check CEMS	$10,000	
	Initial correlation test	$25,200 to $37,100	
	Prepare QA Plan	$17,000	
	Total Capital Investment		$103,500 to $133,800
Annual Costs	Operation and maintenance	$13,000	
	Annual RATA (O_2 monitor)	$0 to $5,900	
	Quarterly absolute correlation audit (ACA)	$1,000 to $7,100	
	Recordkeeping	$7,600	
	Annual review and update	$1,000 to $4,500	
	Capital recovery	$14,800 to $19,100	
	Response correlation audit (RCA) [b]	$15,100 to $26,500	
	Total Annualized Cost		$52,500 to $83,700

a. Costs reported in year 2004 dollars by adjusting the year 2000 costs reported in Reference 1 using the *Chemical Engineering* Plant Cost Index for process instruments.
b. Cost estimate assumes one RCA performed each year. If less frequent RCA are required by the applicable rule (e.g., once every 18 months, once every 3 years), then annual costs for the PM CEMS will be lower.

The above costs are high in and of itself. However, these costs do not include what might be required to establish correlation curves for multiple fuel and work to try to find a way to make this technology work effectively in scenarios it has never been successfully applied. Given the range of fuels, production rates and other variables in a given installation that would have to be accounted for, this cost is believed to be a small fraction of the true cost for applying this technology.

There are much more effective tried and true technologies that are currently used for assuring compliance that have been demonstrated to be effective in a variety of situations. For example, bag leak detection systems, baghouse pressure drop and many other technologies which EPA has included in their Compliance Assurance Monitoring Guidance would be much more effective and accurate indicators of problems with control technology. These tried and true and less costly approaches should be adopted to assure compliance. EPA should not force industry to use an unproven technology which is unlikely to be effective in a variety of situations when a simpler more elegant technological solution is already at hand.

For the above reasons, EPA must abandon its proposal to use PM CPMS as an indicator of effective operation.

6. Bag leak detectors

As an alternative to the extremely expensive particulate matter CEMS installation EPA proposes, EPA should allow the installation and operation of bag leak detection systems in accordance with the proposed rule's §63.7525(j)(1) through (8) in addition to the existing opacity monitors and pressure drop monitoring. The bag leak detection system provides ongoing monitoring of the bag house component performance and provides for continuous compliance demonstration.

Method 5 stack testing is performed at the rated capacity of the boiler. At this rated capacity, all systems for particulate control are maximized as well (e.g., the air/cloth ratio in the baghouse, the ID fan output, ductwork losses, etc.). Hence, for particulate matter, stack testing conditions are the worst case operating conditions. At lower loads, the basic design parameters for the particulate collection system and for the combustion air management are not as taxed so it would be reasonable to expect that at lower loads, particulate emissions on a lb/MMBTU basis would be lower than the stack test. If all systems that were operating during the stack test continue to operate properly during normal operation, continuous compliance with the stack test can be determined due to the nature of particulate matter emissions behavior. One CIBO member already operates and maintains PS1 certified opacity monitors on all three units as well as monitoring baghouse pressure drop.

C. Liquid HCl Emission Limit Compliance Alternative

EPA should provide the same compliance flexibility to ICI fuel oil fired sources for compliance with the Subpart DDDDD HCl emission limit as EPA has provided in the utility MATS final rule. While Subpart DDDDD liquid HCl emission limit is also applicable to other liquid fuels, there is no rational reason to not provide the above alternative limited to fuel oils fired in ICI boilers and process heaters. With such an alternative, the same ASTM test methods should also be incorporated by reference in Subpart DDDDD.

All of the reasoning described below, and the approach provided by EPA for the utility MATS final rule, are equally applicable to fuel oils utilized by boilers and process heaters subject to 40 CFR 63, Subpart DDDDD. Fuel oil utilized by ICI boilers and process heaters is the same commercial grade fuel oil as that used by electric utility units, so that there is no differentiation between those oil fuels relative to the potential for chloride content due to water.

In the final Utility MATS rule, 40 CFR Part 63, Subpart UUUUU -- National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units, EPA provided the following alternative to measure oil fuel moisture for ongoing compliance with HCl and HF emission limits for liquid fired units:

63.10005…
(i) Liquid-oil fuel moisture measurement. If your EGU combusts liquid fuels, if your fuel moisture content is no greater than 1.0 percent by weight, and if you would like to demonstrate initial and ongoing compliance with HCl and HF emissions limits, you must meet the requirements of paragraph (i)(1)-(5) of this section.
(1) Measure fuel moisture content of each shipment of fuel if your fuel arrives on a batch basis; or
(2) Measure fuel moisture content daily if your fuel arrives on a continuous basis; or
(3) Obtain and maintain a fuel moisture certification from your fuel supplier.
(4) Use one of the following methods to determine fuel moisture content:
(A) ASTM D95-05 (Reapproved 2010), "Standard Test Method for Water in Petroleum Products and Bituminous Materials by Distillation," or
(B) ASTM D4006-11, "Standard Test Method for Water in Crude Oil by Distillation," or
(C) ASTM D4177-95 (Reapproved 2010), "Standard Practice for Automatic Sampling of Petroleum and Petroleum Products," or
(D) ASTM D4057-06 (Reapproved 2011) "Standard Practice for Manual Sampling of Petroleum and Petroleum Products."
(5) Should the moisture in your liquid fuel be more than 1.0 percent by weight, you must
(A) Conduct HCl and HF emissions testing quarterly (and monitor site-specific operating parameters as provided in §63.10000(c)(2)(iii) or
(B) Use an HCl CEMS and/or HF CEMS.

EPA also incorporated by reference in the final Subpart UUUUU the following ASTM test methods applicable to the above compliance alternative:

§63.14 Incorporation by Reference.
* * * * *
(b) * * *

(69) ASTM D95-05 (Reapproved 2010), Standard Test Method for Water in Petroleum Products and Bituminous Materials by Distillation, approved May 1, 2010, IBR approved for §63.10005(i)(4)(A).
(70) ASTM D4006-11, Standard Test Method for Water in Crude Oil by Distillation, approved June 1, 2011, IBR approved for §63.10005(i)(4)(B).
(71) ASTM D4057-06 (Reapproved 2011), Standard Practice for Manual Sampling of Petroleum and Petroleum Products, approved June 1, 2011, IBR approved for §63.10005(i)(4)(C).

(72) ASTM D4177-95 (Reapproved 2010), Standard Practice for Automatic Sampling of Petroleum and Petroleum Products, approved May 1, 2010, IBR approved for §63.10005(j).

EPA discussed inclusion of the above alternative in the Preamble as follows:

2. Moisture Content of Oil

Comment: A number of commenters stated that studies suggest that chloride in fuel oil can result from contamination during transportation and processing of crude oils and then be emitted as HCl during combustion. For example, the commenters asserted that the chloride contamination of crude oils can occur as a result of the ballasting of tanker ships with seawater. However, the Oil Pollution Act of 1990 requires all new oil tankers to be double hulled and establishes a phase out schedule (by the middle of the decade) for existing single hulled tankers with un-segregated ballasts. Because of the role of seawater contamination in introducing contaminants into the oil, the commenters suggest that the EPA set a percent water content limit for fuel oil at a level of 1.0 percent, rather than setting HCl and HF emissions limits. This would encourage handling and transport practices to limit salt water contamination. One commenter recommended a standard of 1.0 percent water because several of the lowest HCl and HF emitting units currently require percent water (or water and sediment) specifications between 0.5 percent and 1.0 percent.

Response: The EPA is providing the alternative compliance assurance approaches in the final rule for liquid oil-fired EGUs of demonstrating compliance through either specific HCl or HF measurements or by demonstrating that the moisture content in the fuel oil remains at a level no more than 1.0 percent.

The EPA is not aware of any FGD systems installed on oil fired EGUs. Thus, it is only the quality of the oil, and the level of HAP constituents contained therein, that can be relied upon for ensuring compliance.

In the proposal preamble, we stated:

> We believe that chlorine may not be a compound generally expected to be present in oil. The ICR data that we have received suggests that in at least some oil, it is in fact present. EPA requests comment on whether chlorine would be expected to be a contaminant in oil and if not, why it is appearing in the ICR data. To the extent it would not be expected, we are taking comment on the appropriateness of an HCl limit. See 76 FR 25045.

> Commenters refer to certain studies that provide a plausible reason for the chloride/fluoride contamination of fueloils. We found this reason persuasive and accordingly areproviding alternative compliance approaches in the final rule to demonstrate compliance with the acid gas HAP standards. Specifically, sources can demonstrate compliance through either specific HCl or HF measurements or by demonstrating that the moisture content in the fuel oil remains at a level no more than percent.

In addition, the EPA provided further similar support and discussion of the compliance alternative in the Response to Comments documents for the final MATS rule:

> EPA's Responses to Public Comments on EPA's National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-Fired Electric Utility Steam Generating Units December 2011 Volume 1 of 2, p. 609-610, 726; EPA's Responses to Public Comments on EPA's National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-Fired Electric Utility Steam Generating Units December 2011 Volume 2 of 2, p. 60-61, 254.

The data from the liquid units setting HCl floors (below) shows the compliance alternative is equally appropriate for these units. As with the MATS units, liquid units setting HCl floors for IB MACT have no acid gas controls, and therefore emission limits are achieved due to the fuels combusted.

EPA DATA: Liquid Fuel Units Used to Set HCl floors

FacilityID	UnitID	Pollutant	90% Fuel Category	Total Control	Minimum Test Average	Number of Tests	Data Type	Rank	In Top 12%?
SCMilliken-Dewey	D30	Hydrogen Chloride (HCl)	Liquid	No HAP APCD Control	1.00E-04	1	ET	1	YES
TNInvistaChattanooga	EU003 - Vaporizer #2	Hydrogen Chloride (HCl)	Liquid	No HAP APCD Control	1.77E-04	2	ET	2	YES
MIConsumerEnergyCo-Campbell	EUKEWANEEBOILER	Hydrogen Chloride (HCl)	Liquid	No HAP APCD Control	1.78E-04	1	FA	3	YES
OKIPValliant	Power Boiler EUG-D2	Hydrogen Chloride (HCl)	Liquid	No HAP APCD Control	2.90E-04	1	FA	4	YES
PABoeingRidleyPark	033	Hydrogen Chloride (HCl)	Liquid	No HAP APCD Control	4.21E-04	1	ET	5	YES
CTElectric Boat	EMU 17	Hydrogen Chloride (HCl)	Liquid	No HAP APCD Control	4.21E-04	1	ET	6	YES
SCDAKAmericas	P8F	Hydrogen Chloride (HCl)	Liquid	No HAP APCD Control	4.23E-04	1	ET	7	YES
MEFPLEnergyWyman	Unit #5	Hydrogen Chloride (HCl)	Liquid	No HAP APCD Control	4.89E-04	1	ET	8	YES
NCMCASCherryPoint	CP-152-BOIL-03	Hydrogen Chloride (HCl)	Liquid	No HAP APCD Control	7.00E-04	1	ET	9	YES
MNGPDuluth	EU33 Boiler #3	Hydrogen Chloride (HCl)	Liquid	Electrostatic Precipitator	7.42E-04	1	ET	10	YES
MIConsumerEnergyCo-Campbell	EUAUXBLR12	Hydrogen Chloride (HCl)	Liquid	No HAP APCD Control	7.78E-04	1	ET	11	YES

D. Emission Testing Consistency with 5-Year Title V Permit Review Cycle

EPA should modify the finalized emission testing requirements so that they are consistent with the 5 year Title V permit review cycle. Annual compliance testing is extremely expensive and the benefits of conducting emission tests more frequently then every 5 years do not justify the costs. In addition, as noted in CIBO's Petition for Reconsideration, there is likely to be a shortage of testing and laboratory resources under the current emission testing schedule.

CIBO appreciates the change in the frequency of performance testing from annually in the final rule to once every three years in the reconsideration rule. However, requiring a performance test once every five years, as is required in many Title V Permit renewals, will still accomplish the same assurance of compliance at a reduced cost to the regulated source.

A significant amount of testing will be required by sources to determine the compliance status with respect to the rule and to evaluate and select available control strategies. Capital projects to install necessary control equipment cannot proceed until the testing and evaluation is complete. Due to the high number of sources affected by the rule that have the same concerns, it is likely that availability of stack testing personnel and laboratory facilities to conduct tests will be limited, adding to the time required to complete this essential first step. As outlined below, annual compliance testing requiring multiple test runs for purposes of compliance will further reduce the availability of testing and laboratory resources.

EPA acknowledges that the cost of testing small boilers and process heaters is prohibitive. While the cost of emissions testing larger units is less prohibitive, EPA must consider these costs when establishing the frequency of testing.

The benefits of testing more frequently than every 5 years do not justify the costs. HAP emissions change only when operating parameters change (e.g., firing rate, maximum contaminant input limits for chloride and mercury, type of fuel, combustion efficiency, oxygen content, etc.) or when design changes occur. Absent these changes to an affected source, operating parameters established by implementation of Boiler MACT are more than sufficient to ensure that emissions will not significantly change over time. Furthermore, the Boiler MACT provisions require owners and operators to measure and monitor prescriptive operating limits, as well as monitor, measure, and keep records of each type of fuel on a continuous basis to verify compliance with limits established during the compliance test. The Boiler MACT regulations also stipulate that sources must perform testing under a representative operating load and require sources to maintain within 110% of the average operating load observed during testing. Based on these stringent monitoring requirements, the operating parameters established during testing are sufficient for a source to demonstrate compliance for a 5-year period. Modifications will be tested under the provisions for new and modified sources, and do not need to be considered in ongoing test requirements.

EPA has underestimated the cost of emissions testing necessary to comply with Boiler MACT. Typical industrial boilers combust a variety types of fuels. This practice is necessary for industry to maintain competitive fuel pricing. In the preamble to the rule, EPA cites, industry average costs per compliance test ranging from \$60,000 to \$90,000 per test. In many cases, however, sources may be required to perform 2 to 3 or even more tests to provide data on the range of fuels being combusted. These annual compliance testing costs of $60,000 to $270,000 are unreasonable and do not take into consideration the monetary impact associated with the identification and investigation of new fuel sources. In addition, testing annually requires an exorbitant amount of company resources to plan, schedule, and perform the required testing which have not been included in the above mentioned cost estimates.

Other regulations support a 5-year testing cycle. For example, 40 CFR §75 requires low mass emissions units to establish NOx emissions curves based on testing conducted every 5 years. Several states require that testing be conducted upon each 5-year Title V permit renewal. All affected major sources subject to Boiler MACT are required to have Title V Permits. The Title V permitting program provides the appropriate vehicle to implement a 5-year test requirement.

E. CEMS QA/QC Requirements

The CEMS QA/QC requirements established by EPA are confusing and extremely burdensome to sources. For example, many industrial boilers and process heaters are subject to a variety of federal and state regulations. The federal and state regulations often require slightly different data reduction requirements and QA/QC for CEMS systems. Another issue is the practical matter of needing to train personnel how to address a data signal, which can be different depending what rule is applicable. CIBO restates by reference here its position set forth in the Petition for Reconsideration, which includes a detailed discussion of the burdens associated with the CEMS QA/QC requirements and a description of a more reasonable and defensible methodology.

F. Fuel analysis

1. Fuel Analysis Requirements for Gases Should be Further Revised

We agree with EPA's determination that no fuel analysis for chloride is required for gases and that operators are not required to conduct the mercury fuel specification analyses for gaseous fuels that are natural gas, refinery gas, or otherwise subject to another subpart of part 63.[19] EPA also should exempt those sources using process gases that otherwise are regulated under Parts 60 and 61 from conducting a fuel specification analysis. Specifically, §63.7521(f)(2) should be amended with the addition of the bold language noted to read:

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

EPA has already extended the exemption for boilers serving as control devices to those controlling gaseous streams subject to Parts 60 and 61.

In addition, §63.7510(a)(2)(iii) appears to require mercury fuel analysis for natural gas:

[19] 76 Fed. Reg. at 80633, to be codified at § 63.7521(f)(1)-(2).

> "You are not required to conduct a chlorine fuel analysis for any gaseous fuels. You must still conduct a fuel analysis for mercury on gaseous fuels unless the fuel is exempted in paragraphs (a)(2)(i) through (iii) of this section."

EPA should clarify this paragraph to indicate that mercury analysis is also not required for natural gas or refinery gas.

2. Facilities Should not Have to Conduct Monthly Fuel Analysis if no New Shipments Have Been Received Since the Last Fuel Analysis was Conducted

Section 63.7515(f) requires monthly fuel analysis if a facility is complying with numeric emission limits using fuel analysis rather than stack testing:

> "If you demonstrate compliance with the mercury, hydrogen chloride, or total selected metals based on fuel analysis, you must conduct a monthly fuel analysis according to § 63.7521 for each type of fuel burned that is subject to an emission limit in Table 1 or 2 to this subpart."

Some facilities may burn certain fuels subject to numeric emission standards only part of the year, and burn natural gas at other times. These facilities should not have to conduct monthly fuel analysis if they have not received additional fuel shipments since the last fuel analysis was performed.

IX. ADDITIONAL ISSUES

A. Additional Flexibility is Needed for Determining Appropriate Sorbent Injection Rates

The proposed rule requires development of operating parameter limits (OPLs) based on the values achieved during the performance test. In many cases, these levels will be appropriate only for certain modes of operation. For example, the absolute sorbent injection rate observed during the performance test conducted under full load and using the worst case fuel mix will not correlate to the sorbent injection rate necessary during startup or periods of lower load. Frequently, sorbent injection rates are set using a feedback loop from a CEMS or CPMS to avoid wasting sorbent. EPA has acknowledged that the sorbent injection rate will vary with load in Table 7, which allows sources to adjust the sorbent injection rate by a load fraction. However, as EPA requires sources to test at the worst case fuel mix for chloride and mercury and this fuel mix may differ from the typical day to day fuel mix, EPA should also allow adjustments to sorbent injection rates based on fuel mix. For example, if a boiler is capable of burning both coal and biomass and tested at 100% coal firing for the mercury performance test, the carbon injection rate for periods of normal operation should not only be adjusted based on load but also by the percentage of coal being fired. If a boiler is burning natural gas or other clean fuel during a certain operational period, sorbent injection is not necessary.

B. Additional Flexibility is Needed for Other Operating Parameters

In Table 7, EPA only allows for operating parameter limit variation due to boiler/process heater load fraction to be applied to sorbent and activated carbon injection rates. However, variations with load and other operating conditions also occur for the other operating parameters- wet scrubber pressure drop, pH, and liquid flow rate, ESP voltage and secondary amperage. Flue gas flow rate and characteristics vary over load and with other operating variables such as fuel quality, to the extent that the single hourly average value determined during the high load steady state performance test will not apply to other conditions if overall performance is optimized. EPA should provide an allowance for any operating parameters to vary with unit load fraction as applicable to the operating parameter and specific affected source, and recognize that those operating parameters do not necessary vary in a linear relationship with load, e.g., pressure drop typically varies with the (flow).

C. 30-day Averaging Periods are Appropriate for Operating Parameter Limits

The industrial boilers and process heaters that will be subject to this rule often burn multiple types of fuels and are subject to frequent load swings. Therefore, the emissions from these units vary over the course of a day, depending on the fuel burned and the required production. EPA acknowledged during the Phase 2 ICR test program that emissions from industrial boilers and process heaters are variable by requesting multi-year historical stack test data and conducting 30-day fuel and emissions monitoring studies.

The court reviewing the Brick MACT authorized EPA to consider intra-unit variability and EPA's work on the Hazardous Waste Combustion MACT confirmed the importance of considering variability. Therefore, we believe it is inappropriate for EPA to set limits under the Boiler MACT that cannot be met consistently by a top performing unit overall operating conditions. One way to consider a unit's variability in emissions is to set a longer averaging time for compliance with an emission limit.

There are factors beyond the boiler operator's control that can cause emissions to vary over a period of days, not hours. For example, the weather will impact moisture content of solid fuels, which will affect how the fuels combust over a period of days. For all types of boilers, the pollutant content of the fuel will vary over a period of days, as evidenced by the range of results obtained during the 30-day fuel sampling required by EPA for many ICR Phase 2 participants. Therefore, we support a 30-day rolling average period to account for operational and emissions variability.

We also request that EPA add a 30-day averaging period to the operating load requirement. Table 4 (item 8) and Table 8 (item 11) require operators to maintain the operating load of each unit such that it does not exceed 110 percent of the average operating load recorded during the most recent performance test. For the same reasons provided above for the other operating parameters, EPA should allow a 30-day averaging period for operating load so short term high load periods that are more than 10 percent above the tested load do not result in deviations. Facilities make every attempt to schedule stack tests during periods of high utilization, but sometimes need to operate at more than 100 percent of the load achieved during the stack test for short periods of time in order to meet operational demands. The way the requirement is currently written implies that the 110 percent load limitation is instantaneous. CIBO recommends that both Table 4 (item 8) and Table 8 (item 11) be modified to include a stipulation that the operating limit is on a 30-day rolling average basis. For comparison, 40 CFR 63 Subpart JJJJJJ Table 7 (item 9) does include the 30-day rolling average basis for the operating load limit.

X. PARAMETRIC MONITORING DATA SUBMISSION TO WEBFIRE

The Proposed rule requires sources, within 60 days after the reporting periods ending on March 31, June 30, September 30, and December 31, to transmit quarterly reports to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (www.epa.gov/cdx). 40 CFR sec. 7550 (j)(proposed); 76 Fed. Reg. 32015. For each reporting period, the quarterly reports must include all of the calculated 30-day rolling average values based on the daily CEMS (CO and Hg) and CPMS (PM CPMS output, scrubber pH, scrubber liquid flow rate, scrubber pressure drop) data. 40 CFR §§63.7750(b) and 63.7550 (j).

EPA offers multiple unavailing reasons for imposing this never-before required submission of data. This quarterly requirement of data submission is not reasonable given the increased burden on sources and its lack of utility in ensuring compliance with the standards in this rule or improving environmental protection. EPA does not even attempt to assess the burden on sources, and the benefits it describes relate to the usefulness to EPA for future rulemaking efforts.

Among the reasons EPA propounds for this new reporting requirement is that by collecting performance test data now, the agency may not need to issue as many or as substantial CAA Section 114 information requests to obtain this data in the future. 75 Fed. Reg. 32,016. By mandating the perpetual submission of vast amounts of data to EPA, EPA subverts the intent of Congress in the Paperwork Reduction Act (PRA), which requires EPA and other agencies to obtain advance approval from the Office of Management and Budget (OMB) before imposing information production burdens on regulated sources. This information collection request approval process ensures that the burdens on regulated sources are assessed in advance and minimized whenever possible. EPA cannot avoid this requirement by requiring the piecemeal submission of "test data already collected for other purposes" on a perpetual basis.

Before mandating such a requirement, EPA must assess the additional burden that EPA thereby shifts to sources. Sources already must submit in many cases multiple MACT semi-annual compliance reports . With each report, a corporate officer or designee must certify the authenticity and accuracy of the submission. There is no rational need for sources to undertake another time-consuming reporting procedure, four times per year, and assume the additional substantial compliance risk that comes with this new requirement. EPA does not even attempt to assess the substantial additional burden of this requirement. Instead, with absolutely no record support, EPA claims that imposing this requirement will help EPA develop future regulations and thereby "save industry, State/local/Tribal agencies, and EPA time and money and work. . ." 76 Fed. Reg. 32016.

EPA describes as "easy" the use of its electronic reporting tool (ERT) and enhanced data management tools. 76 Fed. Reg. 32016. Yet data submission via the ERT will take a substantial amount of time and requires that multiple judgments be made by personnel entering and editing the data, and will require review and clearance by officers who are ultimately responsible for its accuracy. The aggregated number of labor hours across all the thousands of covered sources is absent from the record and would not be justified by EPA's rationales.

In addition to burden, EPA should also assess thoroughly the volume of data it will receive each quarter vis-à-vis the functionality and dependability of its computer server. The tremendous volumes of electronic data that EPA will receive on the same day, four times per year, has not been quantified, nor has EPA apparently thought out how much of its computer server this will consume, the cost of the data management and storage, and potential risk to system stability.

In addition, to make use of this data, EPA staff must be prepared to sort through the volumes of information, ensuring the data has been properly quality assured in order to make the submissions useful to the Agency. The information collection and quality assurance associated with development of the Boiler MACT itself is an excellent example of the effort required to ensure reliable data goes into a database. The alternative to manually quality assuring data is to develop data checking software. This has been done in EPA's Part 75 reporting program, but the effort on the part of sources to ensure data is uploaded in an acceptable format with the monitoring associated plans is costly and an unnecessary burden on sources. One CIBO member having four units in the NOx Budget Trading program spends $25,000/year just to support the data QA and submission requirement of this Part 75 program.

By imposing this data submission requirement on sources that have a State regulator, EPA illegally supersedes the authority of the States. Once a State has adopted the boiler MACT into its SIP, sources have no ongoing data submission requirements to EPA, and EPA does not thereafter oversee their compliance with the standards. To impose this requirement on sources in States with delegated programs defeats the structure of the Clean Air Act and makes sources responsible not only to the State regulator but also to EPA in a manner not contemplated by the Act.

Finally, the rule should make clear that sources in delegated States should not submit this high-volume data to States, which are not likely to want to gather and store the data.

XI. ENERGY ASSESSMENT

In the 2011 Final Boiler MACT Rule, EPA grounded its authority to require sources to conduct an energy assessment in CAA §112: "the energy assessment will generate emission reductions through the reduction in fuel use beyond those required by the floor" and that "the requirement to perform the energy audit is, of course, a requirement that can be enforced and thus a standard." 76 Fed. Reg. 15,632-33.

CIBO challenged that basis of authority in prior comments on these rules and reasserts those positions here. In short, an energy assessment does not purport to limit emissions, nor impose more stringent standards than the MACT floor and is, therefore, not a beyond-the-floor standard consistent with the text of the Clean Air Act. Furthermore, even if efficiency measures identified in the energy assessment were actually implemented, the reduced demand for the output of a regulated source is not an "emission control" technology to limit emissions from the regulated source. CAA §112(c)(2); 42 U.S.C. § 7412(d)(3). In addition, by defining the energy assessment as a control, with the goal of reducing energy use, EPA illegally attempts to reduce demand for the product of the regulated source, in this case, the boiler. The scope of the energy assessment is illegally broad, and the proposed amendments to the scope in the Proposed Reconsidered rule do not cure the illegality. The energy assessment lacks a relationship to HAP reduction, and EPA provides no record basis demonstrating such a relationship. The rule irrationally assumes cost savings from projects that may (or may not) be identified or ever implemented by sources.

Section 114. Even as EPA proposes to not require sources to submit the energy assessment report to EPA under §112, EPA asserts in the proposed reconsidered Area Source rule, "the authority to obtain the energy assessment as authorized by section 114," 76 Fed. Reg. 80,540.

As CIBO has noted in earlier comments, the scope of the assessment is illegally broad. As proposed in the Reconsidered Rule, it remains as such, requiring sources to consider, inter alia, the "operating characteristics of the facility, energy system specifications, operating and maintenance procedures, and unusual operating constraints . . .;" "major energy consuming systems;" "available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage . . .;" and to identify "major energy conservation measures." 76 Fed. Reg. 32,014; *see also* 76 Fed. Reg. 80,664. EPA's authority under §112 is limited to setting emission limits for the affected combustion unit and does not extend to non-§ 112 sources, or generally to the entire "facility." What EPA requires goes far beyond its §112 authority.

In addition, EPA makes clear in the proposed Reconsidered Rule that the definition of "energy use system" is a non-exclusive list of examples of systems that a source may be required to include in its energy assessment. 76 Fed. Reg. 80,651. EPA emphasizes the open-endedness of this requirement in response to a comment, stating that the definition of "energy use system" is "intended only to list examples of potential systems that may use the energy generated by affected boilers and process heaters." 76 Fed. Reg. 80,615. Therefore, as broadly as "energy use system" is already defined, as applied to specific sites, the assessment requirement could be even broader.

The definition of energy assessment is too broad because it appears to establish obligations beyond the boiler or process heater source. The rule in relevant part states that an energy assessment, or audit, is an in-depth energy study identifying all energy conservation measures appropriate for a facility given its operating parameters. It leads to the reduction of emissions of pollutants through process changes and other efficiency modifications. The purpose of an energy assessment is to identify energy conservation measures (such as, process changes or other modifications to the facility) that can be implemented to reduce the facility energy demand which would result in reduced fuel use.[20] EPA is requiring that the energy assessment be conducted by energy professionals and/or engineers that have expertise that covers all energy using systems, processes, and equipment.[21]

[20] See 76 Fed. Reg. 80624, "To further address POM and Hg emissions, this final rule also includes an energy assessment provision that encourage modifications to the facility to reduce energy demand that leads to these emissions."
[21] See Table 3 to Subpart DDDDD and the definition of qualified energy assessor in 63.7575.

The broad definition of the scope of an energy assessment is unreasonable. The language attempts to include equipment and systems far beyond the intent of the "Industrial, Commercial and Institutional Boilers and Process Heaters" rule. In its definitions, EPA correctly defines a "boiler" and a "process heater" to refer to enclosed devices containing a controlled flame that are used to recover heat. However, EPA attempts to vastly expand the scope of this rule in its definition of a "boiler system" by including the term "energy use systems". This expansion in scope is reinforced in EPA's choice of language describing the scope of energy assessments to include modifications to the facility. The expansion in scope is further reinforced by implication that those conducting the energy assessments should have expertise that covers all energy using systems.[22]

Energy usage within most manufacturing facilities is directly and inextricably related to the processes being used and the qualities of the specific products being produced. The sweeping language EPA has proposed to modify manufacturing processes out of concern for HAP and non-HAP emissions would grant EPA the authority to redesign proprietary and confidential manufacturing systems at industrial sites across the country. This would require many, if not most, industrial facilities to grant third-party auditors and EPA access to a highly Confidential Business Information (CBI). Giving EPA the authority to mandate changes to manufacturing processes would put at risk competitive advantages that many manufacturers have secured for their products through careful technical and commercial analysis. Neither third-party auditors nor EPA fully understand the myriad technical and commercial analyses developed over years, or in some cases decades, by companies to optimize energy consumption, product performance and quality, and safety. This would paradoxically create a regulatory vehicle that would allow EPA the authority to mandate changes in energy-consuming manufacturing processes without first developing the in-house expertise to understand the full breadth of the processes, and with it the impact of potential changes to the safety of employees, competitive advantage of the product, or upstream and downstream processing activities at integrated sites.

EPA has authority to regulate HAP emissions from major sources under section 112(d) of the Clean Air Act. This attempt to further regulate the way major sources consume energy under this rule is beyond EPA's authority. EPA should eliminate its definitions of "boiler system" and "energy use system". EPA should further limit the scope of energy assessments to "boiler(s)" and "process heater(s)" as currently defined.

A. Amendment to Scope

The Reconsidered Rule amendment to the scope of the assessment does not cure its illegality, and is arbitrary. In the Preamble, EPA asserts that it revised the requirement to address comments that the scope of the assessment was too broad. However, EPA pared back the scope of the assessment in one minor respect, which does not cure the problem. The assessment as re-proposed in the Reconsideration Rule remains illegally broad. The rule still defines "energy use system(s)" to include without limitation, process heating & cooling, in addition to boiler systems, machine drives, HVAC, and lighting. Further, the proposed amendment creates a division among affected sources that arbitrarily imposes a greater burden on facilities with peripheral

[22] See Table 3 to Subpart DDDDD for the requirements of the energy assessment and the definitions of boiler, process heater, boiler system, energy use system, and energy assessment at 63.7575.

power demand supplied by energy made onsite than on facilities that rely more heavily on purchased power.

The rule continues to define energy assessment to include “energy use system(s).” 76 FR 80651. EPA now proposes to cover only “energy use systems that are under the control of the owner/operator.” 76 Fed. Reg. 80664.

EPA proposes to amend this definition because, as EPA explains, it did not intend the scope of energy assessments to include “energy use systems using electricity purchased from an off-site source” nor “energy use systems located off-site.” 76 Fed. Reg. 80664. EPA excludes them because EPA concludes they are inconsistent with its intent to cover systems that are directly related to the emissions of the regulated boiler. CIBO agrees they should not be covered by this rule, nor should any of the other energy using systems that continue to be covered by the rule.

Energy use systems located off-site and systems that run on purchased power should never have been covered by the rule, because the source category and emission source is the boiler. Although EPA appears to concur that scope is a concern, in fact EPA selectively addresses the comments, focusing only on the systems off-site and running on purchased power. EPA does not address the other more fundamental concern, relating to all other systems still covered by the rule.

While the scope of the covered energy use systems should certainly be narrowed, EPA’s proposed exclusion of systems that run on purchased power creates an arbitrary distinction among efficiency measures at a facility based on the source of power. There is no logic to requiring a more reaching assessment of energy systems by sources that depend more heavily power produced onsite than by sources that purchase power. EPA’s logic – the sole basis of this regulatory requirement – is that reduced energy demand = less fuel used = lower emissions from the combustion source. It matters little whether the power is produced by a utility or by an industrial boiler, if EPA rationally applies its reasoning to regulatory requirements. In addition, it is not always apparent what the source of the power is for any individual energy-consuming system at a facility. As EPA has made clear, the goal is "to reduce the facility energy demand which would result in reduced fuel use." 76 Fed. Reg. 15,573. While CIBO supports EPA’s narrowing the scope of the energy assessment, the current definition remains over-broad and lacking in record support and legal authority.

B. Percent of affected boilers.

However, if EPA continues with this broad scope of coverage for the energy assessment, further clarification is required to limit the scope of effort relative to the percent of affected boiler(s) and process heater(s) energy output for different size facilities. Specifically, it is unclear how the percentages in the Energy assessment definition are to be applied. CIBO believes that EPA’s intentions are to limit the scope of assessment based on energy use by discrete segments of a facility, and not by a total aggregation of all individual energy using elements of a facility, because the latter would be disjointed and unwieldy at best. The applicable discrete segments of a facility could vary significantly depending on the site and its complexity. However, CIBO believes the following addition to the Energy assessment definition in 63.7575 would help resolve current problems and allow for more streamlined assessments:

"(4) *the on-site energy use systems serving as the basis for the percent of affected boiler(s) and process heater(s) energy output in (1), (2), and (3) above may be segmented by production area or energy use area as most logical and applicable to the specific facility being assessed (e.g., product X manufacturing area; product Y drying area; building Z).*"

C. Maximum time of assessment.

If EPA imposes an energy assessment, it should include the proposed change to the maximum time of the assessment. In the Reconsidered Boiler MACT Rule, EPA clarified that the time to conduct the energy assessment may be extended "at the discretion of the owner or operator of the affected source." 76 Fed. Reg. 80,651. CIBO supports this approach regarding the timing to conduct energy assessments.

In the Final Boiler MACT Rule, EPA included "stated 'maximum time'" language in the definition of energy assessment, 76 Fed. Reg. 80,615, which could have implied that a deviation or a potential violation would occur if the energy assessment effort exceeded the listed time limits. CIBO supports EPA's new approach because it recognizes that actual times for conducting the assessment can exceed stated maximum times depending on site-specific conditions. A clear statement is critical so that deviations or enforcement is not applicable to the elapsed times expended on energy assessments.

D. Data submission and collection.

If EPA imposes an energy assessment, it should not be submitted to EPA and additional CBI protections are needed. In the Reconsidered Rule, EPA proposes to remove the requirement that sources submit their energy assessments upon a request from EPA. 76 Fed. Reg. 80,641; 40 C.F.R. § 63.7530(e). EPA notes that it recognizes the sensitivity of confidential business information (CBI) contained in energy assessments. EPA's Response to Public Comments on EPA's National Emission Standards for Hazardous Air Pollutants for Major Source Industrial Commercial Institutional Boilers and Process Heaters - Volume 1 of 2 (Response to Comment Excerpt Number 215). CIBO supports protecting CBI to the fullest extent allowed. As CIBO stated in its Petition for Reconsideration of the Final Area Source Rule, EPA should provide the same level of CBI protection for area sources as it does for major sources. Submission of energy assessments is not required under the Final Boiler MACT Rule. CBI is equally an issue for companies operating area source boilers as it is for major source boilers and process heaters. As such, a similar approach in both rules is justified.

Here, EPA is exercising its authority under §112. *See, e.g.,* 76 Fed. Reg. 80,625. As EPA acknowledges, §112 directs the agency "to develop NESHAP which require existing and new major sources to control emissions of HAP using MACT based standards." *Id.* An energy assessment is not an emission standard; therefore, if EPA would like to collect this information for policy purposes or to inform other rulemaking efforts, it must comply with the procedural requirements to issue a §114 request.

As explained above, EPA must comply with the PRA, which requires that the agency receive approval from OMB before issuing similar §114 requests to ten (10) or more respondents collecting substantially similar information in any 12-month period. 5 C.F.R § 1340.3(c). The OMB's approval is in the form of an Information Collection Request ("ICR"), which must go through public notice and comment. Courts have determined that compliance with an information request is not required where "the demand for information or documents is arbitrary and capricious, an abuse of discretion, or otherwise not in accordance with law." *U.S. v. Pretty Prod., Inc.*, 780 F. Supp. 1488, 1506 n.23 (S.D. Ohio 1991).

The regulatory text of the Reconsidered Boiler MACT Rule indicates that sources must demonstrate compliance with the energy assessment requirement by including in their Compliance Status Report a certification that the facility has completed an energy assessment consistent with the regulatory requirements:

> (e) You must include with the Notification of Compliance Status a signed certification that the energy assessment was completed according to Table 3 to this subpart and is an accurate depiction of your facility.

Section 63.7530(d), 76 Fed. Reg. 80,641.

However, the Preamble of the Reconsidered Boiler MACT Rule appears to indicate that in addition to the foregoing certification, sources must also submit documentation of cost effective energy conservation measures:

> Further, all owners or operators of major source facilities having boilers and process heaters subject to this final rule are required to submit to the delegated authority or the EPA, as appropriate, documentation that an energy assessment was performed by a qualified energy assessor and documentation of the cost-effective energy conservation measures identified by the energy assessment.

76 Fed. Reg. 80,603.

As CIBO asserted in its comments on the Proposed Rule, much of the analysis of cost-effective efficiency measures will be CBI, and sources should not be required to submit that information to EPA. EPA's regulations provide that information must be protected from disclosure to protect trade secrets and a business' right to limit the use or disclosure of information "by others in order that the business may obtain or retain business advantages it derives from its rights in the information." 40 C.F.R. § 2.201(e). Commercial or financial information involuntarily submitted by a company to EPA is entitled to confidentiality if "disclosure of the information is likely to . . . cause substantial harm to the competitive position of the person from whom the information was obtained." *Nat'l Parks & Conservation Ass'n v. Morton*, 498 F.2d 765, 770 (D.C. Cir. 1974); *Critical Mass Energy Project v. Nuclear Regulatory Comm'n*, 975 F.2d 871, 879 (D.C. Cir. 1992) (reaffirming the *National Parks* test for determining whether information submitted under compulsion is confidential); *see also* 40 C.F.R. § 2.208(e)(1). Parties claiming confidentiality need only show "competition and a likelihood of substantial competitive injury." *CNA Fin. Corp. v. Donovan*, 830 F.2d 1132, 1152 (D.C. Cir. 1987).

EPA's regulations provide that emissions data cannot be protected from disclosure as CBI. 40 C.F.R. § 2.301(e). "Emission data" is "any source of emission of any substance into the air" that is "necessary to determine the identity, amount, frequency. . . of any emission. . . emitted by the source." 40 C.F.R. § 2.301(a)(2)(i); *see also RSR Corp. v. EPA*, 588 F. Supp. 1251, 1255 (N.D Tex. 1984).

However, the information collected to comply with the energy assessment requirement is not "emissions data." 40 C.F.R. § 2.301(e). It is not "necessary" to determine emissions emitted by a source. *Id.* Rather, the energy assessment includes:

- An evaluation of operating characteristics of the facility, specifications of energy using systems, operating and maintenance procedures, and unusual operating constraints;
- An inventory of major energy consuming systems;
- A review of available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage;
- A review of the facility's energy management practices and recommendations for improvements;
- A list of major energy conservation measures and their energy savings potential;
- A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments.

The foregoing information is commercially valuable because its release would potentially provide competitors with a window into the reporter's current operations, operating costs, and expansion plans. For EPA to require the public disclosure of information of this nature (including engineering plans or the costs of energy savings projects), ignores the competitiveness implications of such disclosure. A company that develops a method to significantly reduce its energy costs – whether through improved maintenance practices or new projects - will not want its competitors to be aware of such proprietary information. Similarly, that company would not want to make its competitors aware of any operating constraints that might highlight weaknesses within a facility. If energy assessments are made publically available, competitors that took a minimalist approach in conducting their own energy assessments could benefit from the disclosures of others without incurring the time and expense to independently develop those plans. *See Webb v. Dep't of Health & Human Serv*., 696 F.2d 101, 103 (D.C. Cir. 1982). As a result, reporters that prepare more comprehensive and detailed energy assessments would suffer irreparable harm. EPA is not authorized under the CAA or its implementing regulations to cause companies such injuries by mandating the disclosure of proprietary information. 42 U.S.C. § 7414(c); 40 C.F.R. § 2.301(b)(i).

The lapse of time would not diminish the sensitivity of disclosing this information. There is no time after which this information could be released that would avoid these potential competitive harms. Given these concerns, it would not be appropriate to impose a time limit on the confidentiality of the energy assessment information.

CIBO objects to requiring sources to submit their energy assessments even if they are afforded CBI status because those protections are not necessarily complete or permanent. Such protections are insufficient because EPA CBI determinations are subject to reevaluation. 40 C.F.R. § 2.205(h). EPA has the discretion to modify prior CBI determinations and conclude that CBI is no longer entitled to confidential treatment because of a change in applicable law or newly discovered or changed facts. *Id.*

For the foregoing reasons, EPA should amend the Preamble to remove this statement about submitting such documentation so that the Preamble is consistent with the rule text, which only requires entities to submit a certification that the energy assessment was conducted.