American Chemistry Council

February 21, 2012

EPA Docket Center
U.S. Environmental Protection Agency
Mail Code 2822T
1200 Pennsylvania Avenue, NW
Washington, DC 20460

RE: Docket ID No. EPA–HQ–OAR–2002-0058, National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters (76 Fed. Reg. 80598, December 23, 2011)

The American Chemistry Council (ACC)[1] appreciates the opportunity to comment on U.S. Environmental Protection Agency's (EPA or the Agency) Proposed Reconsideration Rule National Emissions Standards for Hazardous Air Pollutants; Industrial/Commercial/Institutional Boilers and Process Heaters, (76 Fed. Reg. 80598, December 23, 2011) (hereinafter "Reconsideration Proposal") which proposes to modify certain portions of the Agency's March 21, 2011 final NESHAP for these major sources (Final Boiler Rule). ACC represents the leading companies engaged in the business of chemistry and its member companies own and operate many boilers and process heaters that will be subject to the Final Rule and the final provisions resulting from this Reconsideration Proposal.

EPA's modifications are based on the Agency's May 18, 2011 Notice of Reconsideration (Docket No. EPA-HQ-OAR-2006-0790) and administrative petitions for reconsideration that EPA received from ACC and other interested parties. ACC submitted extensive comments EPA on the June 4, 2010 proposed NESHAP for Major Sources (2010 Proposed Boiler Rule). ACC also submitted, pursuant to § 307 of the Clean Air Act, a petition asking the Agency to reconsider certain provisions in the Final Rule. ACC appreciates that EPA has incorporated several of our recommended changes from these previous submissions into this Reconsideration Proposal as we believe that they would help maximize emissions reduction while minimizing

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[1] *The American Chemistry Council (ACC) represents the leading companies engaged in the business of chemistry. ACC members apply the science of chemistry to make innovative products and services that make people's lives better, healthier and safer. ACC is committed to improved environmental, health and safety performance through Responsible Care®, common sense advocacy designed to address major public policy issues, and health and environmental research and product testing. The business of chemistry is a $720 billion enterprise and a key element of the nation's economy. It is one of the nation's largest exporters, accounting for ten cents out of every dollar in U.S. exports. Chemistry companies are among the largest investors in research and development. Safety and security have always been primary concerns of ACC members, and they have intensified their efforts, working closely with government agencies to improve security and to defend against any threat to the nation's critical infrastructure.*

regulatory burden. ACC further believes that EPA could further improve the implementability and efficacy of this rule by incorporating the recommendations described in our attached comments.

If you would like to discuss any of the comments in more detail, please contact me at (202) 249-6411 or Lorraine_Gershman@americanchemistry.com.

Sincerely,

Lorraine Krupa Gersh

Lorraine Krupa Gershman
Director, American Chemistry Council

Attachment

Comments on
EPA's Proposed Reconsidered Rule
National Emissions Standards for
Hazardous Air Pollutants;
Industrial/Commercial/ Institutional
Boilers and Process Heaters
76 Federal Register 80598, December 23, 2011
Docket EPA–HQ–OAR–2002-0058

Submitted by
The American Chemistry Council

I. EXECUTIVE SUMMARY

The American Chemistry Council (ACC) is pleased to submit comments on the Environmental Protection Agency's (EPA or Agency) proposed reconsidered National Emission Standards for Hazardous Air Pollutants (NESHAP) for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters (Reconsideration Proposal). As described in detail in these comments, it is imperative that EPA craft a rule that protects public health and the environment without requiring significant financial expenditures that result in no added environmental benefit. In this time of severe economic hardship and fierce competition from overseas manufacturers, it is critical that the Nation's regulatory construct protect jobs and American manufacturing.

ACC strongly supports EPA's conclusion that work practices are appropriate for gas-fired boilers, for dioxin/furan emissions, and for periods of startup and shutdown. In each of these cases EPA determined it was not feasible to prescribe or enforce a numeric emission limit and properly exercised the authority provided in Clean Air Act §112(h) to establish work practice standards.

ACC also supports EPA's proposal to move to 30-day rolling averages in lieu of 12-hour block averages. A 30-day rolling average period accounts for the variability in emissions and operations from ICI boilers.

ACC supports EPA's additional of a subcategory in the Final Boiler Rule for limited use units. However, EPA should add an annual capacity factor to the definition of such units.

ACC supports some of EPA's changes to the monitoring requirements. It is appropriate for EPA to allow the use of a continuous oxygen trim analyzer system instead of oxygen continuous emission monitoring system (CEMS). We also support the monitoring flexibility provided by EPA by allowing the use of hydrogen chloride (HCl) and mercury (Hg) CEMS for those facilities that already have such monitors. However, EPA should remove the requirement for large industrial, commercial, and institutional (ICI) boilers to install particulate matter (PM) continuous parameter monitoring system (CPMS), as such technology has not yet been field-tested on such boilers.

ACC supports EPA's efforts to review and consider additional emissions data submitted from ICI boilers. We remain concerned that, in many proposed subcategories, EPA continues to use only a select set of data to determine the maximum achievable control technology (MACT) floor. In some cases, this results in unachievable emission limits. We are particularly concerned about the proposed subcategories and emission limits for solid fuels, which need to be revised to reflect the differences between coal-fired, biomass, and combined coal/biomass units. Rather than subcategorizing coal boilers by design for PM, EPA should combine all coal boilers into one subcategory with one set of PM and alternative total selective metals (TSM) emission limits. Furthermore, EPA should establish separate subcategories for Hg and HCl for coal, biomass, and combination boilers, to reflect the differences in boiler design.

ACC questions why EPA continues to require annual performance stack testing for facilities that utilize emissions averaging, in conjunction with extensive monitoring and recordkeeping provisions. EPA has not demonstrated why it is necessary for these ICI boilers to undergo such frequent stack testing.

ACC believes EPA should also allow owners/operators to include existing coal-fired boilers that are repowered to fire Gas 1 in the emissions averaging approach for coal-fired boilers.

ACC remains concerned that the reconsidered carbon monoxide (CO) limit is unachievable. Studies have demonstrated that setting strict CO levels for ICI boilers does not directly correlate to the reduction of emissions of other organic compounds, and there were concerns with the reliability of the test methods. Instead, EPA should set a work practice standard for CO for coal-fired units, as was done in the February 2012 final Mercury and Air Toxics Standards (MATS) rule.

ACC believes that EPA should abandon the approach it is taking to addressing malfunctions, that is, offering an affirmative defense, and instead should use its statutory authority in §112(h) to establish a work practice or operational standard that would reduce emissions during a malfunction event.

EPA's reconsidered definition of energy assessment is improved from the Final Boiler Rule, but is still impermissibly broad, and should be further narrowed to comport with the requirements of § 112 of the Clean Air Act and to avoid placing unnecessary burdens on facilities. The scope of the energy assessment should focus solely on the boiler and process heater units.

Finally, there are a number of proposed definitions that need further clarification and revision, including "natural gas curtailment," "hot water heater," and "liquid fuel."

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II. DISCUSSION OF ISSUES FOR RECONSIDERATION

A. SURROGATES AND SELECTED REGULATED POLLUTANTS

1. Alternative Total Selected Metals Limit

a. ACC supports the inclusion of alternate TSM limits

ACC believes inclusion of a total selected metals (TSM) emission limitation as an alternative to the particulate matter (PM) emission limits in the Final Boiler Rule is appropriate, since the emissions of these non-mercury metals are the hazardous air pollutants (HAPs) the standard targets for regulation and reduction. We believe that a TSM option will provide greater flexibility for sources while still reducing the emissions of non-mercury HAP metals. This will offer the opportunity for sources to achieve low metal HAP emissions similar to those achieved with PM, but potentially at a lower cost. As the implementation of the Final Boiler Rule will be extremely costly for industry, the use of the TSM alternative could help provide some cost savings by avoiding the installation and operation of PM continuous parameter monitoring system (CPMS) for units >250 MMBtu where the TSM limits are viable.

For purposes of the final Boiler rule, TSM would be defined as the sum of 8 non-mercury HAP metals. It would not be practical or necessary for EPA to set emission limits for each of these individual metals due to the fact that so many of them are present below detectable levels. The use of a TSM alternative is therefore appropriate, and TSM emissions can be calculated using available metals emission data for each fuel type and subcategory. EPA should indicate in the final Boiler rule that when calculating TSM emissions based on Method 29 test results or fuel analysis data, if individual metals are non-detect for all 3 test runs or fuel samples, emissions of those metals should be counted as zero.

b. EPA should establish TSM limits for liquid units

There is no compelling reason to establish TSM limits for solid and gas 2 boilers and not for liquid boilers. EPA's final Mercury and Air Toxics Standards (MATS)[2] provides a choice between complying with a PM or a TSM standard for liquid electric generating units (EGUs). If EPA is concerned that the limited amount of data available makes the Maximum Achievable Control Technology (MACT) floor based on the top 12 percent of units for which data are available might be unrepresentative of what the true top performing units should be achieving, then EPA could set TSM emission limits based on the top performing units in each of the PM subcategories.

c. EPA should allow emissions averaging if sources comply with the TSM alternative

Emissions averaging should be allowed for units complying with TSM emission limits, as it is allowed in the final MATS rule (§63.10009). Section 63.7522 of the Reconsideration Proposal

[2] 77 Fed. Reg. 9304, February 16, 2012

does not include emissions averaging for TSM. However, the compliance provisions (either stack testing or fuel sampling and analysis) are virtually identical as those for hydrogen chloride (HCl) and mercury (Hg) for which emissions averaging is allowed. EPA provides no explanation in the preamble to the Reconsideration Proposal for not including emissions averaging for TSM, and since emissions averaging is allowed for PM, there is no reason not to include it for facilities choosing to comply with the TSM limits.

2. WORK PRACTICE FOR DIOXIN/FURAN EMISSIONS

Based on the record supporting the Final Boiler Rule, EPA has very little data on dioxin/furan emissions from industrial boilers and process heaters since the majority of emission measurements are below the level that can be accurately measured using Method 23. Furthermore, the science is still uncertain on how dioxin/furan emissions are formed and could be controlled from industrial boilers and process heaters. An extensive discussion on the subject can be found in the Docket.[3] Industry has experience controlling dioxin/furan emissions from sources such as municipal waste combustors where dioxin/furan emissions occur at much higher levels than those reported by boiler/process heater sources in the industrial boiler MACT ICR testing program. There is no data showing that dioxin/furan emissions at ultra-low levels can be controlled using add-on control technology. The comments submitted by the National Council for Air and Stream Improvement (NCASI) on the 2010 Proposed Boiler Rule, provided significant support on this point.[4] Their comments specifically focused on method detection and quantitation limit issues, and demonstrated that the proposed standards are below the 95th percentile of practical quantitation limits achieved over all tests. Comments submitted by the Dow Chemical Company, also provided technical support on this issue.[5]

Quantifying the actual, extremely low or non-existent dioxin emission levels for the industrial, commercial, and institutional (ICI) Boiler MACT floor units is technologically impracticable (as well as economically impracticable, given that the technological problems cannot be overcome by investing reasonable resources into the problem), and thus, it is not feasible to prescribe or enforce an emission standard for dioxin/furan emissions for these units. Furthermore, on February 17, 2012, EPA released its final non-cancer science assessment for dioxins and noted that "*As a result of efforts by EPA, state governments and industry, known and measurable air emissions of dioxins in the United States have been reduced by 90 percent from 1987 levels. The largest remaining source of dioxin emissions is backyard burning of household trash.*" Additionally, the Agency also noted that *"generally, over a person's lifetime, current exposure to dioxins does not pose a significant health risk."*

The EPA's findings further support the Agency's justification under Clean Air Act § 112(h)(1) to establish a work practice standard for dioxin/furan in the Boiler MACT, as was done in the

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[3] Docket ID EPA-HQ-OAR-2002-0058-0287 Chlorinated Dioxin and Furan Formation, Control, and Monitoring, Presented at an ICCR Meeting, September 17, 1997.

[4] Docket ID EPA-HQ-OAR-2002-0058-2804

[5] Docket ID EPA-HQ-OAR-2002-0058-2632

MATS.[6] The required tune-ups and other emissions reductions in the final Boiler MACT will result in improved combustion and minimize conditions conducive to dioxin/furan formation without establishing a numerical emission standard.

Several sets of comments have been submitted that provide more detail on these points. We incorporate those comments by reference:

- AF&PA Comments at EPA-HQ-OAR-2002-0058-3213, reconsideration petition (see in particular Appendix A) at EPA-HQ-OAR-2002-0058-3293, and EPA-HQ-OAR-2002-0058-3366
- CIBO Comments at EPA-HQ-OAR-2002-0058-2702
- ACC Comments at EPA-HQ-OAR-2002-0058-2792
- API/NPRA Comments at EPA-HQ-OAR-2002-0058-2935
- CRWI Comments at EPA-HQ-OAR-2002-0058-2824
- NCASI Comments at EPA-HQ-OAR-2002-0058-2804 and EPA-HQ-OAR-2002-0058-3360
- Analytical Perspectives comments at EPA-HQ-OAR-2002-0058-3301
- ENVIRON Comments at EPA-HQ-OAR-2002-0058-2809

Therefore, ACC continues to strongly support a work practice approach for dioxin/furan emissions from industrial boilers, as these emissions cannot be reliably measured and there is no technically feasible means of ensuring continuous control of these emissions and EPA has stated that current exposures to dioxins do not pose a health risk.

B. OUTPUT BASED EMISSION LIMITS

ACC supports the flexibility provided by the output based emission limits and EPA's acknowledgement of credit that should be provided to sources that improve their energy efficiency and reduce emissions using a pollution prevention-type approach.

C. SUBCATEGORIZATION

1. Solid Fuel

a. There is Not a Strong Technical Basis for Subcategorization of Coal Boilers for PM

Coal-fired boilers should not be subcategorized by boiler design to set PM or TSM emission limits. EPA added a solid fuel subcategory to the Final Boiler Rule that replaced previously proposed separate subcategories for units designed to burn solid fossil-based fuels and units designed to burn solid bio-based fuels. The solid fuel subcategory applied to pollutants identified in the final rule as fuel-based pollutants (PM, HCl, and Hg). Standards for combustion-based

[6] 77 Fed. Reg. 9369, February 16, 2012 ("We are finalizing work practice standards [for organic HAP, including dioxins and furans] because the significant majority of data for measured organic HAP emissions from EGUs are below the detection levels of the EPA test methods….").

pollutants (carbon monoxide (CO)), however, were based on specific subcategories for the various types and designs of combustion units, including the specific primary fuel types the units were designed to combust.

In response to two petitioners' requests for separate subcategories for PM, EPA established a separate PM emission limit for the subcategory "hybrid suspension grate units designed to burn biomass/bio-based solid," which is defined by fuel with moisture content of at least 40 percent. However, in responding to these two petitioners, whose arguments appear to be strongly in support of separate subcategories for biomass units, EPA went a step further by setting separate PM standards for both biomass and coal design subcategories. EPA has no basis for applying the arguments presented to subcategorize *biomass* boilers to now subcategorize *coal* boilers.

Of particular interest to ACC is the decision by EPA to subcategorize the coal-fired boilers into three groups by boiler type (stokers, pulverized coal, and fluidized bed). We agree that PM/TSM limits should be set separately for coal boilers apart from biomass boilers, but we disagree that coal units should be further subdivided. The results of EPA MACT floor determinations for PM by coal design type are counter-intuitive. The limit for coal fluidized bed boilers is highest and the limit for coal stoker boilers is lowest.

There are not enough differences in levels of uncontrolled PM or TSM from these three types of coal-fired boilers to justify subcategorization. A review of EPA's database on controlled emissions does not reveal significant differences. This is evident from Appendices B and C of the ERG MACT floor memorandum found in the docket.[7] Shown below are comparisons of the average of all test runs for top performers in the three coal subcategories compared to the two abovementioned biomass subcategories:

Subcategory	**PM (lb/mmBtu)***
Stoker (coal)	0.007
Pulverized coal	0.0099
Fluidized bed (coal)	0.0088
Stokers burning dry biomass	0.23
Hybrid suspension	0.065

*Average of top performer test runs (Appendix C)

Here it can be observed that the two biomass subcategories differ substantially from the coal subcategories and would seem to merit their own subcategories as described in their petitions. However, there are relatively minor differences in the three coal subcategories.

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[7] EPA-HQ-OAR-2002-0058-3387

The emissions data for coal units do not indicate there is a substantial difference in PM emission rates between stokers, pulverized coal, and fluidized bed coal boilers. Finally, either electrostatic precipitators (ESPs) or fabric filters can be deployed to effectively control PM/TSM emissions from any of these three boiler types. In conclusion, EPA should combine all coal boilers into one subcategory with one set of PM and alternative TSM emission limits.

b. EPA Should Establish Separate Subcategories for Hg and HCl for Coal and Biomass

In the preamble to this Reconsideration Proposal, EPA solicited comments on its decision in the Final Boiler Rule to combine biomass and coal-fired units into one subcategory for the fuel-based HAPs (PM (as a surrogate for non-Hg metals), HCl, and Hg). 76 Fed. Reg. 80607. Previously, in the 2010 Proposed Boiler Rule, EPA had proposed separate standards for biomass and coal-fired units. To establish CO standards, EPA further subdivided coal into stoker, pulverized coal, and fluidized bed, and subdivided biomass into stokers, fluidized beds, suspension burners/Dutch ovens, and fuel cells. The 2010 Proposed Boiler Rule placed certain combination-type units designed to burn both biomass and coal in the coal subcategory if they burned at least 10 percent coal on a heat input basis as an annual average. In justifying these subcategories, EPA recognized the differences between biomass and coal-fired units. *See* 75 Fed. Reg. 32017 (June 4, 2010).

In the Final Boiler Rule, EPA grouped coal-fired boilers with biomass-fired boilers for fuel-based pollutants (Hg, HCl and PM) into a single solid fuel subcategory. *See* 76 Fed. Reg. 15612, Table 1. In neither the Final Boiler Rule MACT Floor memo nor the Final Boiler Rule preamble explaining its rationale for selecting the recommended approach (one solid fuel subcategory) over the alternative approach (to subcategorize coal and biomass) for fuel based pollutants has EPA discussed its approach. Finally, no mention is made of this alternative in the Reconsideration Proposal. The solid fuel grouping is ripe for reconsideration because it appeared for the first time in the Final Boiler Rule, and hence the public did not have an opportunity to comment on it. EPA has offered no further explanation of its decision in the record to the reconsideration proposal.

Coal-fired boilers are fundamentally different than biomass units. For example, a boiler designed to burn coal as its primary fuel cannot burn biomass without experiencing unacceptable performance degradation, including fouling and loss of fan capacity. This is due to the differing chemical constituents of the ash, which influence fouling characteristics (increased fouling potential with biomass), and the significantly higher moisture in biomass versus coal, which increases volumetric flow rate and thereby limits fan capacity with biomass. A pulverized coal boiler with no grate will not be able to accommodate other solid fuels. Additionally, the boiler backpass (convection section) configuration is designed specifically for the fuel type. This is another reason a coal boiler cannot burn significant amounts of biomass, and vice-versa. The Council of Industrial Boiler Owners (CIBO), an organization that represents both designers and manufacturers of boilers as well as boiler owners/operators, produced a document in 2003 entitled "Energy Efficiency and Industrial Boiler Efficiency: An Industry Perspective." The following excerpts from that document provide further evidence that coal and biomass boilers truly are different types of boilers:

> *Wood and biomass are solid fuels with both high hydrogen to carbon and high moisture content (greater than 40%). Because of energy loss due to moisture from the combustion of hydrogen and conversion of moisture to vapor (1000 Btu per pound), it is very difficult to obtain efficiencies, either MCR or annual average, equal to or approaching those of natural gas, never mind, oil or coal. A very good annual average efficiency for a wood or biomass unit may be in the 60% range. While fuel property variations may be better than coal, these variations usually occur in the moisture content with a direct and major impact on boiler efficiency. (page 3)*
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> *Fuel characteristics determine the design of a particular unit. Fuel changes, especially in hydrogen and moisture content outside the range of 1 or 2% for natural gas, 3 to 5% for oil and 10% for coal and other solid fuels, will have an impact on efficiency, both MCR and annual average. When fuels are switched, the interaction of the new fuel and the boiler often produces negative impacts on either the load or the boiler efficiency. These effects often are amplified because of limitations encountered in specific areas of the boiler where these adverse interactions occur. (page 3)*
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> *Fuel type and availability has a major effect. Fuels with high heating values, high carbon to hydrogen ratios, and low moisture content can yield efficiencies up to 25% higher than fuels that have low heating values, low carbon to hydrogen ratios, and high moisture contents. A rule of thumb for the efficiency hierarchy in descending order is coal, heavy fuel oil, light fuel oil, natural gas, and biomass. From these rankings, it is obvious that fuel availability plays a major role. (page 11)*

ACC notes that EPA acknowledged boiler design considerations driven by fuel type in a similar source category MACT standard – the final MATS Rule. In the MATS, EPA observed significant differences in mercury emissions between boilers burning high-rank and low-rank coals and concluded that the different mercury emission standards were appropriate for these two different fuel types. In the final rule preamble, EPA states:

> *"…we believed at proposal that the boiler size was the cause of the different Hg emissions characteristics that led us to propose subcategorization, but many commenters indicated that it was not the boiler size but the fact that the EGUs burned a nonagglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of less than 19,305 kJ/kg (8,300 Btu/lb) (low rank virgin coal) that causes the disparity in Hg emissions." (77 Fed. Reg. 9378, February 16, 2012)*

EPA goes on to explain that it has the latitude under the Clean Air Act (CAA) to base subcategorization on fuel type:

> *"We recognize that some commenters have taken the position that it is unlawful to subcategorize based on factors such as fuel type but nothing in the statute prohibits such an approach and the case law supports this approach to the extent courts have considered subcategorization based on such factors. See Sierra Club v. Costle, 657 F. 2d 298, 318-19 (D.C. Cir. 1981) (differing pollutant content of input material can justify a different standard based on subcategorization authority to "distinguish among classes, types and sizes within categories of new sources"). Furthermore, we believe had*

> *Congress intended to prohibit the EPA from subcategorizing based on an EGU being designed to use and using a certain material input (e.g., fuel) it would have clearly stated such intent in the CAA. However, we believe the Agency could decline to exercise its discretion to subcategorize even if the potential result would be the prohibition of the use of some materials if the circumstances warranted." Id.*

Similar logic applies in the boiler rulemaking, and should be followed to create separate subcategories for biomass and coal. A boiler designed to burn coal cannot fire biomass and meet its operational requirements, and the resulting HCl, Hg, and PM emissions are dictated by boiler design.

ACC understands that there are certain "combination" units that are designed to be able to burn both biomass and coal. If EPA does separate coal boilers from biomass boilers to set PM, Hg, and HCl emission limits, as ACC strongly urges the Agency to do, a problem will surface concerning certain combination boilers specifically designed to burn varying percentages of coal, biomass, and other solid fuels such as tire-derived fuel and biomass residuals. The current biomass subcategory definition includes any such unit that burns greater than 10 percent biomass on an annual heat input basis as a "unit designed to burn biomass/bio-based solids." EPA did this so that the combination units would be subject to CO limits derived from pure biomass units, since combustion of biomass produces a CO emissions profile that is different from combustion of coal. As EPA describes in the Final Boiler Rule preamble, it attempts to resolve the combination boiler dilemma by combining all solid fuel boilers into one subcategory for fuel based pollutants:

> *"For combined fuel units that combust solid fuels, due to the many potential combinations and percentages of solid fuels that are or can be combusted, for the fuel-based pollutants, EPA selected the option of combining the subcategories for solid fuels into a single solid fuel subcategory. For the fuel-based pollutants, this alleviates the concerns regarding changes in fuel mixtures, promotion of combustion of dirtier fuels, and the implementation and compliance concerns."(76 Fed. Reg. 15636)*

ACC maintains that this change in subcategories, designed primarily to address combination units, is inappropriate for coal only-fired units because, as discussed above, coal-fired boilers are different types of boilers than biomass boilers and have very different emission profiles due both to their design and the fuels they are designed to combust.

For regulation of PM, HCl, and Hg, EPA should place any solid fuel boiler that burns at least 10 percent coal on an annual heat input basis in the "unit designed to burn coal/solid fuel" subcategory. Since combination boilers are specifically designed to burn a variety of materials (coal, bark, TDF, biomass residuals, etc.) that do have significant and varying chlorine and mercury contents, such classification may be appropriate for these units. This affords them compliance options to either: (1) shift to a cleaner relative mix of feeds (e.g., less coal and more biomass); or (2) install control technology to meet the emission standards. Just as with coal boilers, it would not be fair or appropriate to require these combination units to meet emission standards set by boilers burning at least 90 percent biomass, the top performers of which have very low levels of mercury and chlorine in their feeds and therefore do not have add-on controls for these pollutants. EPA should allow combination units to remain subject to the CO standards for the applicable biomass design subcategory as long as they burn at least 10 percent biomass. CO emissions from combination units are influenced more by the biomass burned than the coal.

c. The Application of Some Fuel Variability Factors (FVFs) May Be Appropriate for HCl and Hg Emission Limits Once EPA Establishes Separate Subcategories for Coal and Biomass Boilers

In the MACT Floor Memos for both the Final Boiler Rule[8] and the Reconsideration Proposal[9], EPA made the following statement:

> *For existing solid fuel units, EPA reviewed the fuel variability in the UPL calculations prior to multiplying the results by the FVF. In the case of the solid fuel subcategory the fuels used in the top performing boilers varied widely, including coal, petroleum coke, tire-derived fuel, as well as several types of biomass fuel. Based on the heterogeneous make up of the best performing units, we determined that the UPL calculation alone considered sufficient variability in fuel types from best performing units and it was unnecessary to incorporate additional fuel variability through the use of a FVF.*

Once EPA separates biomass and coal units into subcategories, it needs to re-evaluate the variability represented by the upper prediction limit (UPL) calculation. It should follow the procedures from the Final Boiler Rule MACT Floor Memo where both the recommended (combined solid units) and the alternative (separate coal and biomass) datasets are evaluated and determine whether or not FVFs should be applied. What EPA will find is that the datasets have significantly less heterogeneity and FVFs may be appropriate.

Many of the new source limits are set using one 3-run stack test. EPA could further consider variability by using the upper limit (UL) instead of the UPL statistical calculation, and using a 99.9 percent confidence level instead of a 99 percent confidence level, since sources will be required to meet the new source limits at all times. In addition, fuel variability data should be collected for all units setting new source floors and factored into the calculated emission limits. Industrial boilers operate over a variety of conditions and fire a variety of fuels, so adequate consideration of variability is important in setting achievable emission limits. EPA continues to use a pollutant-by-pollutant approach instead of a source-based approach to setting new unit limits, so maximum consideration of variability is imperative.

2. UNITS DESIGNED TO COMBUST LIQUID FUELS

a. EPA Has Appropriately Subcategorized Light-Liquid and Heavy-Liquid Fuels.

From the available data, there is a difference in emissions of PM and CO from heavy and light liquid units. Residual fuel oils typically contain higher levels of ash and somewhat higher levels

[8] EPA-HQ-OAR-2002-0058-3273
[9] EPA-HQ-OAR-2002-0058-3387

of metals[10] than do distillate fuel oils. The combination of these characteristics means that residual fuel oil-fired boilers and process heaters have higher emissions of metal HAPs and PM than boilers and process heaters burning distillate fuel oils (light liquid fuels).

Residual fuel oils also have significantly different firing properties than do distillate fuel oils. The combustion characteristics of light and heavy liquids are different, because these fuels have very different flow/viscosity and atomization characteristics and different energy contents. Per AP-42, typical residual fuel has about 7% more energy per gallon than a distillate fuel oil. As a result of these property differences, at a minimum, heavy fuel oil firing requires different burner tips than are needed when firing lighter fuel oils. The heating value and flame height differences between these fuels may also impose unit design and operating constraints.

In addition, residual fuel-fired boilers must operate a soot blowing cycle on a periodic basis to maintain their heat transfer efficiency, during which opacity and PM levels increase. While the liquids database does not appear to include any data characterizing soot blowing emissions, the proposed emission limits would apply during that time and thus these emissions must be considered. It is, therefore, clear that metal HAP and PM emissions distinguish residual fuel-fired units from distillate-fired units. Indeed, EPA has recognized this fact by creating an implicit subcategory for residual-fuel fired units in the rule by requiring in §63.7525 that residual oil-fired process heaters and boilers (but not distillate units) >250 MMBtu/hr install a PM CPMS.

Thus, from an equipment design and operations standpoint as well as an emissions standpoint, there is a clear distinction between boilers and process heaters firing light liquids versus those that fire heavy liquids. EPA has appropriately subcategorized these units.

b. EPA Should Provide a Liquid HCl Emission Limit Compliance Alternative Similar to that in the MATS Rule

In the final MATS rule, EPA provided the following alternative to measure oil fuel moisture for ongoing compliance with HCl and hydrogen fluoride (HF) emission limits for liquid fired units at §63.10005:

> *(i) Liquid-oil fuel moisture measurement. If your EGU combusts liquid fuels, if your fuel moisture content is no greater than 1.0 percent by weight, and if you would like to demonstrate initial and ongoing compliance with HCl and HF emissions limits, you must meet the requirements of paragraph (i)(1)-(5) of this section.*
>
> > *(1) Measure fuel moisture content of each shipment of fuel if your fuel arrives on a batch basis; or*
> >
> > *(2) Measure fuel moisture content daily if your fuel arrives on a continuous basis; or*

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[10] See AP-42 factors for oil firing, Section 1.3.1. However, HAP metals content in residual fuel oil is strongly influenced by crude oil processed at a given refinery, because these metals volatilize only at very high temperatures and thus typically stay in the bottoms in crude units or in Vacuum units. Thus, the level of metals in a crude oil will be directly related to the metals in residual fuel oil.

(3) Obtain and maintain a fuel moisture certification from your fuel supplier.

(4) Use one of the following methods to determine fuel moisture content:

(A) ASTM D95-05 (Reapproved 2010), "Standard Test Method for Water in Petroleum Products and Bituminous Materials by Distillation," or

(B) ASTM D4006-11, "Standard Test Method for Water in Crude Oil by Distillation," or

(C) ASTM D4177-95 (Reapproved 2010), "Standard Practice for Automatic Sampling of Petroleum and Petroleum Products," or

(D) ASTM D4057-06 (Reapproved 2011) "Standard Practice for Manual Sampling of Petroleum and Petroleum Products."

(5) Should the moisture in your liquid fuel be more than 1.0 percent by weight, you must

(A) Conduct HCl and HF emissions testing quarterly (and monitor site-specific operating parameters as provided in §63.10000(c)(2)(iii) or

(B) Use an HCl CEMS and/or HF CEMS.

EPA discussed inclusion of the above alternative in the preamble to the MATS rule as follows:

The EPA is providing the alternative compliance assurance approaches in the final rule for liquid oil-fired EGUs of demonstrating compliance through either specific HCl or HF measurements or by demonstrating that the moisture content in the fuel oil remains at a level no more than 1.0 percent. The EPA is not aware of any FGD systems installed on oil fired EGUs. Thus, it is only the quality of the oil, and the level of HAP constituents contained therein, that can be relied upon for ensuring compliance.

Commenters refer to certain studies that provide a plausible reason for the chloride/fluoride contamination of fuel oils. We found this reason persuasive and accordingly are providing alternative compliance approaches in the final rule to demonstrate compliance with the acid gas HAP standards. Specifically, sources can demonstrate compliance through either specific HCl or HF measurements or by demonstrating that the moisture content in the fuel oil remains at a level no more than 1.0 percent. (77 Fed. Reg. 9402, February 16, 2012)

In addition, EPA provided further similar support and discussion of the compliance alternative in the Response to Comments documents for the final MATS rule in the document.[11]

All of the above reasoning and the approach provided by EPA for the MATS final rule are equally applicable to fuel oils utilized by boilers and process heaters subject to 40 CFR 63, Subpart DDDDD. Fuel oil utilized by industrial, commercial, and institutional (ICI) boilers and process heaters is the same commercial grade fuel oil as that used by electric generating units (EGUs), and there is no difference between those oil fuels relative to the potential for chloride content due to water. In addition, none of the Subpart DDDDD liquid subcategory HCl MACT floor units utilize acid gas controls. ACC strongly urges EPA to provide the same compliance flexibility to ICI fuel oil fired sources relative to compliance with the Subpart DDDDD HCl emission limit. With such a compliance alternative for HCl, the same ASTM test methods referenced in the MATS rule should also be incorporated by reference in Subpart DDDDD.

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

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

3. *GASEOUS FUEL SPECIFICATION*

ACC and its members strongly support the use of work practices as MACT for gas-fired boilers and process heaters. The following points summarize the arguments presented by ACC and others in previous comments and petitions for reconsideration.

- HAP emissions from gas-fired boilers and process heaters are extremely low and cannot be reliably measured at these low levels due to deficiencies in both laboratory analysis methods and stack sampling methods.

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

- Detection limits reported in the test reports received by EPA during the boiler MACT data collection efforts varied greatly, pointing to the lack of repeatability of measurements at these very low levels.
- As the majority of source emissions are below the reference method quantitation limits, the standard is appropriately set as a work practice standard and not an emission standard, since sources would not be able to accurately measure emissions against any numerical standard
- ACC is not aware of any data that shows a correlation between a reduction in CO concentration and a corresponding reduction in organic HAP emissions below a CO concentration of approximately 100 ppmv for gas fueled (other Gas 1 fueled or Gas 2 fueled) sources. Thus, setting a very low standard for CO does not ensure a proportional reduction in the organic HAP emissions, and may have the unintended consequence of increasing emissions of other pollutants such as nitrogen oxides due to the combustion of additional fuel and suboptimal operating conditions.
- Good combustion practices and periodic tune-ups as work practices will ensure proper operation of gas-fired units and continuous minimization of emissions. In fact, for gas-fired sources, these types of practices serve as MACT currently for minimizing organic HAP emissions.
- Many gas-fired boilers and process heaters do not have vents or stacks to which EPA measurement methods can be applied, and to significantly modify the stacks would be technically infeasible in some applications and would be economically infeasible in many others.
- Measurement infeasibility and control cost issues serve to justify the technical and economic feasibility criteria under §112(h) of the CAA for establishing work practices in lieu of numeric emission standards.

The technical infeasibility of measuring the ultra-low HAP emissions from Gas 1 boilers was highlighted in several sets of comments submitted on the 2010 Proposed Boiler Rule, as identified in the table below.

Docket ID	**Commenter**	**Page Reference**
EPA-HQ-OAR-2002-0058-2792	American Chemistry Council	76-78
EPA-HQ-OAR-2002-0058-0851	American Petroleum Institute and National Petroleum Refiners Association	34-91, appendices
EPA-HQ-OAR-2002-0058-2809	Glenn England, Environ	1-8
EPA-HQ-OAR-2002-0058-2968	ExxonMobil	1-7
EPA-HQ-OAR-2002-0058-2632	Dow Chemical Company	13
EPA-HQ-OAR-2002-0058-3137	Eastman Chemical Company	16
EPA-HQ-OAR-2002-0058-2793	DuPont Engineering Research and Technology	2

Docket ID	Commenter	Page Reference
EPA-HQ-OAR-2002-0058-2702	Council of Industrial Boiler Owners	38-41
EPA-HQ-OAR-2002-0058-3213	American Forest and Paper Association	131-134, 192-193
EPA-HQ-OAR-2002-0058-2775	Automobile Manufacturers ad hoc Group	3-9
EPA-HQ-OAR-2002-0058-2804	NCASI	1-16, appendices B and C

ACC members support the Gas 1 opt-in provision for gases other than natural gas and refinery gas proposed by EPA. We agree with EPA's proposed definition of "other gas 1 fuel" and the mercury content criteria. Additionally, ACC believes that additional criteria such as Btu content and organic HAP content are not needed or appropriate since some process gases have lower Btu content than natural gas (e.g., hydrogen), or higher organic HAP than natural gas (e.g., some chemical process gases), but are still clean burning (i.e., result in HAP emissions that are not feasible to measure).

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

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

For all of the reasons above, ACC believes work practices are also appropriate as MACT for Gas 2 units. The following commenters on the 2010 Proposed Boiler Rule were among those supporting work practices for Gas 2 units based on the fact that these units burning clean process gases that will have low emissions like Gas 1 units.

Docket ID	Commenter	Page Reference
EPA-HQ-OAR-2002-0058-2792	American Chemistry Council	78-83
EPA-HQ-OAR-2002-0058-0851	American Petroleum Institute and National Petroleum Refiners Association	24-26
EPA-HQ-OAR-2002-0058-2968	ExxonMobil	7-11, 15-17
EPA-HQ-OAR-2002-0058-2632	Dow Chemical Company	4-6
EPA-HQ-OAR-2002-0058-3137	Eastman Chemical Company	17-19
EPA-HQ-OAR-2002-0058-2793	DuPont Engineering Research and Technology	2-4
EPA-HQ-OAR-2002-0058-2702	Council of Industrial Boiler Owners	42-47
EPA-HQ-OAR-2002-0058-3213	American Forest and Paper Association	131, 194
EPA-HQ-OAR-2002-0058-2775	Automobile Manufacturers ad hoc Group	21-25

4. *Work Practices for Limited-Use Units*

EPA has appropriately established a subcategory for "limited use" units. Limited use sources operate intermittently and for shorter periods of time (*e.g.*, small package boilers that are only used during plant outages, a backup boiler that runs when other units are being fixed, a peaking unit used to supplement electric generation during particularly hot summer days, a process heater that operates for a few hours at a time to warm up a heat transfer fluid for use in a chemical process, or a process heater that only operates intermittently in order to maintain the temperature of a process fluid in the desired range). Compared to most boilers and process heaters, these units spend a relatively greater percentage of their time starting up and shutting down. As a result, their emissions profiles differ from sources which operate for long periods of time in efficient steady-state manners. For example, the limited-use units are likely to experience higher CO levels as the boiler or process heater heats up during startup due to incomplete combustion. Similarly, many pollution control technologies are either difficult to use or ineffective during startup and shutdown periods and would be cost prohibitive to install and use for only short periods of time during a year. These are just the sort of "class" and "type" distinctions that merit consideration for subcategorization under §112(d)(2).

Because limited use boilers and process heaters do not operate on a regular schedule and typically operate for only short periods of time, emissions profiles for these boilers and process heaters can vary significantly from those of a similar boiler or process heater operating in a steady state. "Combustion units operate most efficiently when operated at or near their design capacity. The combustion efficiency tends to decrease as the unit's load (steam production) decreases."[12] Given their short run times, there are also technological limitations on how effectively emissions from these units can be controlled, particularly for organic HAP emissions.

EPA indicated the following in the responses to comments on the final 2004 Boiler MACT rule: "[W]e could not identify any control technologies that would reduce organic HAP emissions [for limited use boilers]. Therefore, while larger units may emit more than smaller units, ACC has not identified any appropriate technology or method that could be used to reduce organic HAP emissions." [13] Finally, since "limited use boilers, when called upon to operate, must respond without failure and without lengthy periods of startup,"[14] a significantly larger percentage of their annual operation will be devoted to maintenance and readiness testing than other commercial, industrial, or institutional boilers. These differences noted in the 2004 boiler rule remain valid today and justify the creation of a subcategory for limited use boilers and process heaters.

In the Final Boiler Rule, EPA reiterates its support for a limited use subcategory, noting that limited use units are a unique class of units and that forcing them to start up solely to conduct emissions testing would be impractical and lead to increased emissions:

> *"The fact that the nature of these units is such that they operate for unpredictable periods of time, limited hours, and at less than full load in many cases has lead EPA to determine that limited use units are a unique class of unit based on the unique way in which they are used and EPA is including a subcategory for these units in the final rule. The unpredictable operation of this class of units makes emission testing for the suite of pollutants being regulated impracticable. In order to test the units, they would need to be operated specifically to conduct the emissions testing because the nature and duration of their use does not allow for the required emissions testing. As commenters noted, such testing and operation of the unit when it is not needed is also economically impracticable, and would lead to increased emissions and combustion of fuel that would not otherwise be combusted. Therefore, we are regulating these units with a work practice standard that requires a biennial tuneup, which will limit HAP by ensuring that these units operate at peak efficiency during the limited hours that they do operate." 76 Fed. Reg. 15634.*

However, ACC believes that units operating at less than 10 percent of their annual capacity factor or less than 10 percent of the annual operating hours should qualify as limited use units. A capacity utilization factor of 10 percent was chosen for the vacated 2004 boiler MACT final rule as the best means of defining a limited use unit.[15] This definition is equally appropriate for the current rule. EPA has taken a capacity factor approach in the final MATS rule, establishing a subcategory for limited use liquid-fired units with an 8 percent capacity factor (limited-use liquid

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[12] 75 Fed. Reg. 32023 (June 4, 2010)
[13] *See* Response to Public Comments on Proposed Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP EPA-HQ-OAR-2002-0058-0649
[14] National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters; Final Rule, 69 FR 55218, 55232 (September 13, 2004).
[15] *See* National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters; Final Rule, 69 Fed. Reg. at 55223.

oil-fired subcategory means an oil-fired electric utility steam generating unit with an annual capacity factor of less than 8 percent of its maximum or nameplate heat input, whichever is greater, averaged over a 24-month block contiguous period).[16] Therefore, ACC requests that EPA define the limited use subcategory to give sources the option of complying with an annual hourly limit or an annual capacity factor.

D. MONITORING

1. *OXYGEN MONITORING*

a. *The Change from O_2 CEMS to O_2 Trim is Appropriate and Supportable*

In the Final Boiler Rule, EPA included continuous oxygen (O_2) monitoring as the compliance method for sources with a CO limit, instead of mandating the use of CO continuous emissions monitoring system (CEMS). EPA now proposes to amend the O_2 monitoring requirements to allow for the use of continuous oxygen trim analyzer systems instead of oxygen CEMS. (76 Fed. Reg. 80609) EPA also proposes to remove the requirement that the oxygen monitor be located at the outlet of the boiler, so that it can be located either within the combustion zone or at the outlet as a flue gas oxygen monitor. ACC supports EPA's proposal to add flexibility and reduce the cost and burden of the continuous oxygen monitoring requirements, as these changes allow facilities to utilize existing oxygen trim systems rather than installing CEMS.

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 leakage points to avoid erroneous excess air indications which would drive controls in an erroneous direction. This location is also upstream of air preheaters, thus avoiding the erroneous (high 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.

b. *O_2 Trim System Clarifications are Required*

ACC recommends the following changes to the regulatory language to enhance clarity and ensure no negative impact on operations.

[16] *See* 40 CFR 63.10000 and 63.10042.

Oxygen sensing location

The oxygen analyzer system is defined in § 63.7575 of the Reconsideration Proposal 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. ACC recommends that this language be modified as follows to allow latitude in the exact location of the sensing point:

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

Oxygen trim system set point

Paragraph (2) of proposed § 63.7525(a) states:

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

First, ACC believes 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 ACC believes 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, ACC recommends that § 63.7525(a)(2) be revised to read as follows:

> *(2) You must operate the oxygen analyzer <u>and trim</u> system with the oxygen level set at <u>or above</u> the minimum percent oxygen by volume that is established as the operating limit for oxygen according to <u>Table 7</u> to this subpart <u>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.</u>*

2. *PM CEMS*

EPA is proposing to employ PM CPMS rather than emissions compliance monitoring (CEMS). This proposal places sources in an untenable position if they are required to install, certify, and operate these monitoring systems. While EPA states these monitors do not have to comply with Performance Specification 11, presumably to reduce compliance burden, , EPA's proposed rule language requires the same host of requirements in a site-specific monitoring plan as any other continuous monitoring system (see § 63.7540(a)(9) and § 63.7505(d)).

ACC is not clear on how a source should "certify" their PM CPMS other than through the use of PS-11. EPA apparently recognizes that the burden of complying with PS-11 is unreasonable for coal-fired ICI boilers as it states in the 2010 Proposed Boiler Rule preamble at p. 80610. While EPA has required PM CEMS in the final MATS, those boilers are many times larger than ICI boilers with commensurately larger PM emissions and associated impact. They also operate at relatively steady loads compared to ICI boilers that have to respond to frequent load swings. ACC requests EPA remove from the final rule the requirement to install PM CPMS monitoring for boilers larger than 250 MMBtu/hr. Before requiring such a substantial monitoring burden on ICI sources, EPA should further evaluate these systems via field studies to determine the real-world performance.

At a minimum, EPA should provide clarification that units in the biomass subcategories do not have to install PM CPMS, even if they fire more than 250 MMBtu/hr of fossil fuel. EPA notes in the preamble that these types of monitors cannot be feasibly applied to biomass units, due to significant technical concerns and the unpredictable variety of biomass fuel constituents and fuel moisture content. *Id.* at. 80609.

Beyond the objection to the practicality and cost of PM CPMS on these types of boilers, ACC is concerned about the requirement to limit the 30-day rolling average PM CPMS output data (milliamps) to less than the operating limit established during the performance test (see Table 8, item 2c). As discussed below, ACC believes this requirement is unreasonable and would reduce operating flexibility of these boilers to an untenable level.

First, it imposes a much tighter operating envelope than even the final rule, which only required the 30-day rolling average to remain less than the emission standard (see § 63.7525(b)(3) of the Final Boiler Rule). At the very least, if EPA were to require these monitoring systems, they should allow the operating limit to be increased by the ratio of the allowable PM emission rate to the actual PM emission rate during the performance test.

Second, it does not account for variation in the measurement device output that is likely to occur during long-term operation. The fact that the measurement system is not held to some defined reference method will add to the uncertainty of the data. Even if it were held to PS-11, those specifications include a correlation coefficient of 0.85 between measured and predicted stack gas PM concentrations and the systems will have a high error band compared to the actual PM emission levels and indicate non-compliance when that is often not the case.

3. CEMS ALTERNATIVE FOR HG

EPA solicited comment in the 2010 Proposed Boiler Rule on its inclusion of an option to use Hg CEMS in lieu of periodic testing, fuel sampling analysis, and parameter monitoring. EPA included this option at § 63.7525(l) with further detailed requirements at § 63.7540(a)(14) and (15). ACC notes that while EPA does not mention it in the preamble to the 2010 Proposed Boiler Rule, it is also proposing a similar option for use of HCl CEMS in response to petitioners' requests.

ACC supports the flexibility provided by this proposed option, as facilities that have these monitors installed should be able to take advantage of their use in order to comply with this rule and should not be required to perform additional stack testing or parameter monitoring. Some facilities may select these options in order to obtain more operating flexibility and to better assure continuous compliance with the standards. EPA has precedent for allowing use of these CEMS as it included this provision in the MATS. ACC supports the use of a 30-day rolling average to determine compliance. As mentioned above, emissions averaging with no 10% penalty should be allowed if CEMS are used.

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

ACC requests that EPA amend the restriction found at § 63.7525(l)(8) that allows substitution of CEMS, but only if an add-on control to comply with the Hg or HCl emission limits is used. ACC sees no need for such a restriction. A source without add-on control should be able to control its fuel supply or feed rate such that it complies with the standards and demonstrates continuous compliance using a CEMS.

4. *USE OF SULFUR DIOXIDE (SO_2) CEMS FOR DEMONSTRATING CONTINUOUS COMPLIANCE WITH THE HCL EMISSION LIMITS*

ACC agrees with EPA's conclusions that acid gas HAP control efficiencies would be better than SO_2 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 SO_2 CEMS to demonstrate continuous compliance. EPA drew this same conclusion in the recently finalized MATS rule and set alternative SO_2 emission limits.[17]

ACC suggests SO_2 continuous monitoring be allowed as a CPMS, and that the maximum 30-day rolling average SO_2 operating parameter limit be set during a 3-run performance test where HCl emissions are demonstrated to comply with the final HCl emission limit. This method of continuous compliance should be allowed on any unit that utilizes an acid-gas control technology including wet scrubber, dry scrubbers, and duct sorbent injection.

5. *MINIMUM DATA AVAILABILITY*

ACC requests EPA reconsider its response to the requests to add minimum CEMS data availability requirements. At least two commenters, Dominion and the Industrial Minerals Association, noted that the requirement to have valid CEMS data for all operating hours is not realistic.[18] There will be times, even with a well maintained CEMS, when the system will be out of operation. EPA's response that, somehow, lengthening the averaging period for PM CEMS from 24 hours to 30 days addresses these comments is inadequate.[19] ACC notes that the final Commercial/Industrial Solid Waste Incinerator (CISWI) rule provides minimum data availability requirements for PM CEMS. *See* 40 C.F.R. 60.2730(n)(14). EPA's response that the need for minimum data availability provisions such as those in NSPS Subpart Da no longer exists due to EPA's better understanding of the need for continuous data collection and the dramatic improvement in CEMS data availability (citing Acid Rain Program) is also not persuasive. SO_2 CEMS used under the Acid Rain Program differ starkly from some of the other CEMS (Hg, HCl, PM) discussed above. SO_2 CEMS are a mature technology in widespread use. Even mature CEMS technology such as SO_2, NO_X, and CO should be provided some reasonable amount of downtime. Therefore, ACC respectfully requests that EPA reconsider its decision to not include

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[17] The MATS preamble at 77 Fed. Reg. 9367 states "For coal-fired EGUs, this final rule regulates HCl as a surrogate for acid gas HAP, with an alternate of SO2 as a surrogate for acid gas HAP for coal-fired EGUs with FGD systems installed and operational…."

[18] See Response to Comments, EPA-HQ-OAR-2002-0058-2908.1, excerpt number 31; EPA-HQ-OAR-2002-0058-2740.2, excerpt number 14.

[19] EPA responded that, "[r]egarding comments on PM CEMS, we have modified the language from the proposed 24-hour block to a 30-day rolling average. We disagree with the commenter about applying the data availability used in Da to the PM CEMS data collection. The Agency has developed a better understanding of the need for continuous data collection since Da was published and the equipment and software have dramatically improved as shown by the acid rain program CEMS data availability success. The monitoring system must operate at all time the process is operating." Response to Comments, EPA-HQ-OAR-2002-0058-2908.1, excerpt number 31.

minimum data availability requirements, and to propose for comment a reasonable allowance for equipment downtime in 40 C.F.R. 63.7525(a)(6).

6. Averaging Times

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

The court reviewing the Brick MACT (40 CFR 63, Subpart JJJJJ - NESHAP for Brick and Structural Clay Products Manufacturing) confirmed EPA's authority to consider intra-unit variability,[20] and EPA's Hazardous Waste Combustor MACT (40 CFR 63, Subpart EEE, NESHAP for Hazardous Waste Combustors) confirmed the importance of considering variability. [21] Therefore, ACC believes it is inappropriate for EPA to set limits under this boiler rule that cannot be met consistently by a top performing unit under all operating conditions. One way to consider a unit's variability in emissions is to set a longer averaging time for compliance with an emission limit.

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

ACC also requests that EPA add a 30-day averaging period to the operating load requirement. Table 4 (item 8) and Table 8 (item 11) require operators to maintain the operating load of each unit such that it does not exceed 110 percent of the average operating load recorded during the most recent performance test. For the same reasons provided above for the other operating parameters, EPA should allow a 30-day averaging period for operating load so short term high load periods that are more than 10 percent above the tested load do not result in deviations. Facilities make every attempt to schedule stack tests during periods of high utilization, but

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[20] EPA relied on a 2004 decision, *Mossville Environmental Action Now v. EPA*, 370 F.3d 1232 (D.C. Cir. 2004), holding EPA may consider emission variability in estimating performance achieved by best-performing sources and may set the floor at level that best-performing source can expect to meet ''every day and under all operating conditions.''

[21] See for example 73 Fed. Reg. 64071: "To account for the bias in the analytic method, we corrected all TCl emissions data that were below 20 ppmv to 20 ppmv. We accounted for within-test condition emissions variability for the corrected data by imputing a standard deviation that is based on a regression analysis of run-to-run standard deviation versus emission concentration for all data above 20 ppmv. This approach of using a regression analysis to impute a standard deviation is similar to the approach we used to account for total variability (i.e., test-to-test and within-test variability) of particulate matter emissions for sources that use fabric filters."

sometimes need to operate at more than 100 percent of the load achieved during the stack test for short periods of time in order to meet operational demands. The way the requirement is currently written implies that the 110 percent load limitation is instantaneous. ACC recommends that both Table 4 (item 8) and Table 8 (item 11) be modified to include a stipulation that the operating limit is on a 30-day rolling average basis. For comparison, 40 CFR 63 Subpart JJJJJ Table 7 (item 9) does include the 30-day rolling average basis for the operating load limit.

7. *Other Monitoring Issues*

a. *EPA Should Provide Flexibility in Determining Appropriate Fuel Input Operating Limits*

The general compliance plan outlined in the Reconsideration Proposal requires that sources: (1) demonstrate compliance with applicable emissions limitations and work practice standards through the conduct of an initial performance test; (2) establish operating limits based upon results of the performance test; (3) conduct monitoring and maintain records demonstrating that the source is operated on a continuous basis consistent with the operating limits established during the performance test; and (4) periodically repeat the performance testing. Operating parameter limits based on fuel input analysis (e.g., HCI and Hg), are established using Equations 7 and 8 in § 63.7530. Then, on a continuing basis, facilities are required to keep extensive records of all fuels burned in each boiler or process heater during each compliance reporting period. If a source changes fuels, it must re-calculate its fuel input values using applicable equation 7 or 8. If the re-calculated value exceeds the existing limit, the source is required to conduct a new performance test and establish new operating limits.

While this compliance approach may be easy to manage for some sources, especially ones with very stable fuel supply and usage, it may be very cumbersome and burdensome for other sources with variable fuel suppliers and fuel mixes. This approach involves a great deal of recordkeeping and potentially subjects the source to frequent testing requirements if fuel content varies, regardless of the margin of compliance shown during the initial performance test. Under the proposed rule, even if a unit is operating at 50 percent of the applicable emission limit, the facility would be required to re-test if the fuel chloride input increases 1 percent over the level achieved during the initial performance test.

A more appropriate approach is to allow the source to set operating parameters at levels that generate emissions at the emission limits established in the rule. This is the only approach which meets the requirements of the Act, since it is the only approach that does not impose a beyond the floor limit which has not been justified per the requirements of § 112(d). Under this approach, the source would do the performance test using its normal fuel mix, determine operating conditions that show compliance and then adjust those conditions, using engineering calculations to assure it would meet the emissions standards established in Table 1 or 2. If the initial performance test shows emissions at 50 percent of the standard at a particular mercury or chloride fuel input, the fuel input limits should be set at a level higher than the performance test values, taking into account control device operating parameters as appropriate. This approach would be environmentally beneficial and would greatly reduce burdens. It is the only practical way to establish fuel input operating limits.

Compliance could also be demonstrated through the use of fuel purchase specifications. Sources would determine from the performance test a maximum fuel pollutant concentration at which the emissions limitations are achieved. For instance, the performance test may demonstrate that fuels containing chlorine in concentrations less than x lb Cl/MMBtu allow the source to comply with emissions limitations. A facility should be allowed to extrapolate an allowable fuel input based on a comparison of performance test conditions to the applicable emission limit. The source would then set a fuel specification of x lb Cl/MMBtu and would be allowed to burn any fuel of the same general type (e.g., solid, liquid, or gas) as long as it met this specification. Sources could require that the fuel supplier provide periodic certification that the fuel meets the specification, based on analysis, or could establish an internal sampling and analysis program for that purpose. In any case, where common fuels are utilized in more than one unit, common fuel quality data would be maintained and considered applicable to all such units. Continuous compliance could also be demonstrated through ongoing fuel analysis.

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

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

The Reconsideration Proposal requires development of operating parameter limits (OPLs) based on the values achieved during the performance test. In many cases, these levels will be appropriate only for certain modes of operation. For example, the absolute sorbent injection rate observed during the performance test conducted under full load and using the worst case fuel mix will not correlate to the sorbent injection rate necessary during startup or periods of lower load. Frequently, sorbent injection rates are set using a feedback loop from a CEMS or CPMS to avoid wasting sorbent.

EPA has acknowledged that the sorbent injection rate will vary with load in Table 7 of the Reconsideration Proposal, which allows sources to adjust the sorbent injection rate by a load fraction. However, as EPA requires sources to test at the worst case fuel mix for chloride and mercury and this fuel mix may differ from the typical day to day fuel mix, EPA should also allow adjustments to sorbent injection rates based on fuel mix. For example, if a boiler is capable of burning both coal and biomass and tested at 100% coal firing for the mercury performance test, the carbon injection rate for periods of normal operation should not only be adjusted based on load but also by the percentage of coal being fired. If a boiler is burning natural gas or other clean fuel during a certain operational period, sorbent injection is not necessary.

c. *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 $(\text{flow})^2$.

E. EMISSION LIMITS

1. *INCORPORATION OF MINIMUM DETECTION LEVELS AND MEASUREMENT IMPRECISION*

It is not appropriate to treat detection level limited data for purposes of establishing regulatory limits in the same manner as detected values because the uncertainty[22] associated with measurements near or below the method detection limits is too high. In setting the standards in this rulemaking, EPA has acknowledged that the emission limit should not be set below the capability of the applicable test method.[23] ACC supports EPA's decision to multiply the method detection limit by three to approximate the representative detection limit for each pollutant.

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

These issues were also identified in an ASME report entitled "Reference Method Accuracy and Precision (ReMAP), Phase 1," which examined the precision of selected EPA source emission test methods. The report, which is referenced in the Reconsideration Proposal, makes several important points: (1) there are both random errors and systematic errors (bias in the measurement process, (2) "the magnitude of random errors associated with extraction and recovery of the sample from the stack might be expected to vary in proportion to stack

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[22] Uncertainty here refers to the statistical expression of measurement error, such as defined in ASME Performance Test Code 19.1, rather than an inference of something which is unknown.
[23] 76 Fed. Reg. 80611

concentrations," and (3) "estimation of method precision must be based on data from special tests where multiple sampling trains are used simultaneously to determine the stack pollutant concentration." In its proposal, EPA has ignored these issues and considered only the precision of laboratory analytical measurements in establishing method representative detection limits (RDLs). ACC believes that consideration of these issues will result in higher RDL values for several of EPA's reference test methods and will raise the emission standards for many source categories.

2. *CO CEMS-Based Alternative Emission Limits and Monitoring*

a. *Strict CO Levels Will Not Result in Greater Reduction of Emissions of Other Organic Compounds*

ACC is still concerned that the reconsidered CO limit is unachievable, and have heard from vendors that they cannot guarantee the control equipment will be able to meet many of the coal, liquid, and gas CO limits. In addition, some of our members with top performing units equipped with sophisticated combustion controls, such as 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 flame temperature, 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 nitrogen oxides (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 boiler applications manipulate the stoichiometry within the flame to minimize NOx formation. These designs establish a fuel-rich zone for the initial phase of combustion, and then add air at a later stage in the outer regions of the flame. In the initial phase, there is not sufficient oxygen available to form significant amounts of NOx, and in the secondary phase, the flame is much cooler, which also inhibits NOx formation. However, 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 was 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 at lower loads. 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%.

ACC sought the input of a leading supplier of burners for gas- and liquid-fired boiler applications (Coen) to determine what CO emission guarantees would be provided for their installations. For applications for Gas1 category fuels, the CO emission guarantee is generally 50 ppmvd (@ 3% O_2). 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% O_2), 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 have lower heating value than natural gas or refinery gas and burn at lower flame temperatures. They are also commonly limited on the pressure that is available, and 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% O_2) at loads from 25-100% for Gas 2 fuels. Given the right furnace conditions, the guarantee may be as low as 100 ppmvd. 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 has already reached the conclusion that forcing CO emissions below 100 ppmv does not force organic HAP emissions to ultra-low levels in the Hazardous Waste Combustor NESHAP rulemaking. As the Agency states:

> *"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." (70 Fed. Reg. 59462, October 12, 2005)*

ACC agrees that CO is an appropriate surrogate for organic HAP, but believes 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 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. (Note that work practices were retained in the final MATS rule, published at 77 Fed. Reg. 9304.)

> *"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 ICI 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 Final ICI Boiler MACT rule, 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. Rather, EPA should adopt work practice standards for CO for coal-fired units, as it did in the final MATS rule.

If EPA sees the need to continue to have a numerical emission limit for CO for coal-fired units, 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 § 112 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.

b. 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 in Section E.4.h. in these comments, for units that already have CO CEMS for reasons unrelated to the ICI Boiler MACT, compliance with the Boiler MACT stack-test-based CO emissions limitations would be difficult to maintain. Stack tests are required to be run under representative operating conditions, which is typically defined as operating at or near full load consistently for the duration of the stack test. In sharp contrast, CEMS take emissions data on a near-continuous basis, and hence reflect significant variability in emissions (for example, due to load swings and low load conditions) that was not measured during the stack tests used to set the CO standard. This problem is not overcome by statistical manipulation of the CO standard, such as accounting for variability using the UPL method, because such statistical methods unrealistically extrapolate only from the variability measured during stack tests and the variability between stack tests. In other words, this is a classic "apples and oranges" situation where emissions data from CO CEMS are incompatible with emissions data from stack tests used to set the CO standard.

One way for EPA to resolve this incompatibility is to determine that emissions data from CO CEMS are not credible evidence for purposes of assessing compliance with the Boiler MACT 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 Boiler MACT CO standards are based on stack test data, and because the stack tests on which the standards are based were required to be conducted during representative operating conditions (*i.e.*, consistently operating at or near full load), then by definition CO CEMS data taken during periods of operation that do not reflect "representative operating conditions" are not data that are relevant to showing compliance with the standards and should not be used for compliance with the proposed CO limits.

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.

c. *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 then might be found in violation if this corrective action is not taken within a specified period.[24] So, there is clear precedent for applying this concept to the Boiler 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 Boiler 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 the authority and justification to set performance standards for the periods between periodic stack tests.

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[24] See § 63.7530(b)(4)(vii): The operating limit for boilers or process heaters with fabric filters that demonstrate continuous compliance through bag leak detection systems is that a bag leak detection system be installed according to the requirements in § 63.7525, and that each fabric filter must be operated such that the bag leak detection system alarm does not sound more than 5 percent of the operating time during a 6-month period.

d. If EPA Must Set a CO Standard, a CO Standard No Lower Than 100 ppm CO Is Adequate To Assure Complete Control Of Volatile HAPs from Fossil Fuel-Fired Units

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 Boiler MACT CO limits at no lower than100 ppm because lower values would not result in demonstrably lower volatile HAP emissions. This is consistent with DC Circuit rulings 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. *See, for example, National Lime Ass'n v. EPA,* 233 F.3d 625, 637-39 (D.C. Cir. 2000) *National Lime* does not require that the relationship between the surrogate and the HAP be linear. In the case of CO and volatile HAP emissions from industrial boilers, credible data show that the relationship is highly nonlinear at low levels. It would be rational and in keeping with case law for EPA to set a CO standard that reflects this nonlinear relationship.

e. EPA Could Endorse a Petition Process for Unit-Specific CO Limits for Units that Cannot Implement Cost-Effective Modifications

EPA could allow the owner/operator of a source to petition the permitting authority for determination of a unit-specific CO emission limit if 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 $PM_{2.5}$ and its precursors (NOx and SO_2), 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.

f. ACC Supports the Inclusion of Alternate CEMS Based Limits for CO

EPA originally developed a CO standard that boilers must meet at all times based on 3 run stack tests with no acknowledgment of the highly variable nature of CO emissions in solid fueled boilers. CO emissions from boilers can be highly variable, especially with fuel mix and load change. Facilities are typically required to conduct stack tests at least at 90 percent of full load during normal operating conditions. A CO stack test therefore is a small snapshot in time captured during the best operating conditions.

It stands to reason that the Boiler MACT standards should be "internally consistent," in that the test methods or measurement techniques used to gather the data used to set the standard should also be used to determine compliance with the standard. If the test methods or measurement techniques are not consistent (or, at least, shown to be comparable), the methods will not be a true or reasonable measure to determine compliance with the standard.

The CO standards included in the Final Boiler Rule present this problem. The standards are based on short-term stack tests that measured CO over a relatively short period of time during which operating conditions were stable, consistent, and optimal. However, many affected existing units already have CO CEMS for reasons unrelated to the rule. These CEMS collect data over long periods of time and, therefore, reflect variability in unit operations that was not measured in the stack tests on which the standards are based and was not factored into the test-based standards. Thus, these CO CEMS data are not compatible with the test-based standards and cannot reasonably be used to determine compliance with these standards.

ACC appreciates that EPA has acknowledged this problem and proposed to solve it by setting an alternative CO limit for units that choose to determine compliance using CO CEMS. ACC notes that EPA has broad authority in setting standards under § 112(d) to "distinguish among classes, types, and sizes of sources within a category or subcategory in establishing such standards." CAA § 112(d)(1). Industrial boilers with CO CEMS constitute a distinct and easily definable "class" or "type" of source, characterized by the existence of a CO CEMS and distinguished from other boilers by the abundance of CO data that they generate. Therefore, it is reasonable for EPA to set a separate standard based on CEMS data for these sources that is compatible with the greater variability that these data reflect.[25]

It is possible that a CO CEMS-equipped boiler may be required to conduct CO stack tests for reasons unrelated to this rule(e.g., the unit may have a PSD permit or state construction permit that requires such testing). To prevent confusion, EPA should clearly specify in the reconsidered final rule that, if an affected source chooses to comply with the CO CEMS-based standard, it is

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[25] In this Reconsideration Proposal, the Agency states, "For the three subcategories where we have CEMS data for units that are part of the stack test-based MACT floors, we included the CEMS data from those units in the CEMS-based floors because those units are demonstrated best performers for CO." 76 Fed. Reg. at 80612. Since, as explained above, it is reasonable and appropriate for EPA to treat CEMS-equipped units as a different "class" or "type" of sources, EPA does not need to show that the top performing CEMS-equipped units also are top performing stack-test units. EPA is justified in determining class/type-specific MACT floors and corresponding MACT standards.

not subject to the stack test-based CO standard – even if it conducts CO stack tests for other regulatory purposes. Conversely, EPA should also clarify that even if a unit has CO CEMS installed, it may choose to comply with the stack test-based CO limit, and in this case, CO CEMS data are not to be used to demonstrate compliance.

g. The CEMS Location Requirement Should be Clarified

Proposed § 63.7525(a)(1) requires that a CO CEMS monitor the CO level at the "outlet" of the boiler or process heater. Such CO monitors are also required to satisfy the requirements of PS 4, 4A or 4B. It is not possible to certify any gas monitor according to applicable Performance Specifications if the monitor is located at the outlet to the boiler. This inability to certify is caused by stratification of gases at the boiler/process heater outlet. In addition, for units equipped with add-on controls or flue gas recirculation systems the "outlet" could be construed to be either before or after these controls. Since these systems may impact the CO level, the measurement must be after any controls or recirculation (i.e., just before the gas is released to the atmosphere. EPA should revise the last sentence of § 63.7525(a)(1) as follows:

> *If a CO CEMS is used, the carbon monoxide level shall be monitored at the outlet of the boiler or process heater, <u>after any add-on controls or flue gas recirculation system and before release to the atmosphere</u>.*

The installation of the monitor in the stack or breeching leading to the stack would not have any impact on determining the compliance status of the source since the CO data will have to be corrected to 3% O_2, thus negating the impact of any dilution of the stack gas due to leaks in the system.

h. EPA Should Use an Alternate CO CEMS MACT Floor Calculation Methodology

The short term CO limits based on stack test data were developed from limited data sets and the stack test data were obtained at steady state, high load conditions. CO emissions will change as operational conditions within the boiler change, so complying with a stack test based CO limit using a CO CEMS would likely prove impossible. Therefore, EPA has proposed CO CEMS-based limits to more adequately capture the variability of CO emissions over various operating conditions. EPA has proposed 10-day average CO limits for units that have CEMS and has calculated the MACT floors for units with CO CEMS using much the same approach as the MACT floor calculation for units with stack test data.

In this Reconsideration Proposal, EPA considered an alternate method for determining CO CEMS floors that would adjust the CO CEMS-based emission limits to reflect the actual level that was demonstrated to be achieved at all times by those units. (76 Fed. Reg. 80613.) ACC agrees with EPA's alternate approach. This approach would essentially eliminate the possibility of a boiler in the best performing floor itself being in violation of the CEMS-based limit.

Even with this approach, however, EPA should further consider that the available CO CEMS data in some cases were for short periods of time (e.g., 30 day tests required by EPA under CAA § 114 authority). Therefore, simply due to that limited time period, the boilers tested did not experience the full range of operational variations that would likely impact CO emissions and would occur over a longer time period, such as at least one year, where variables such as unit operating condition, seasonal steam demand, and fuel quality would pass through all seasons of the year. Thus, for those cases utilizing short term data, the floor setting methodology should provide further latitude to account for undocumented and undemonstrated inherent variability that would be seen by even the best performing units.

F. MACT FLOOR METHODOLOGY

1. Selection of Confidence Level for CO

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

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

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

2. Other MACT Floor Issues

EPA is proposing a stringent set of emission limits that are not always based on the use of any technology. In many cases, boilers are achieving low emission rates not due to the use of any particular technology, but due to the mix of fuels being fired (which in many cases include fuels with pollutant contents below the limits of detection) or other unit specific characteristics that are not transferable to other sources. Facilities are limited in the fuels that their boilers can fire by design, cost, permits, and fuel availability. EPA should not set limits for hundreds of boilers based on data from a few boilers in which the specific mechanisms resulting in lower emissions are not fully understood and that are not available to all units in the subcategory.

The suite of limits should be achievable by at least 6 percent of existing boilers in each subcategory and the remaining boilers should be able to comply through their range of normal operating scenarios by applying known control equipment solutions. This expectation is not met for a broad range of units. Based on our review of the available data, less than 6 percent of units in the dry biomass stoker, biomass suspension burner, coal stoker, pulverized coal, and all liquid subcategories can comply with the entire suite of applicable limits. This indicates to us that EPA has not adequately addressed the variability of emissions from units in these subcategories.

a. EPA is Using a Biased, Unrepresentative Data Set

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

During Phase I of EPA's data gathering effort (August 2008), EPA requested and received emissions data from over 2,000 sources across all of the subcategories for PM, CO, NOx, and many HAPs. After sifting the data into fuel-based categories, EPA issued a second §114 request in June 2009 requiring additional testing. During this second phase of data gathering, EPA targeted only those sources the Agency knew it needed data from to set the MACT floor (e.g., the top performers) instead of obtaining a sampling of emissions data across the entire population of boilers in a subcategory to assess the variability in performance of boilers in a particular subcategory. In this way, EPA artificially limited the pool of data from which it drew its top 12% "best performing" sources and biased the collection of emissions data. The data are not evenly distributed, but are clustered well below the mean, and since EPA has chosen to select the top12 percent of boilers for which it has stack test data instead of the top 12 percent of boilers for which it has any emissions information, this has resulted in the proposed MACT floors being based effectively on the top 12 percent of the top 12 percent of boilers.

Even more troubling is the fact that in many cases, a large population of boilers is being represented by only a handful of data points. The table below presents information on the number of boilers in each subcategory, the number of boilers for which EPA believes it has data, and the number of boilers on which the MACT floor is based. The only data being used to calculate MACT floors are the data obtained during the ICR and subsequent facility submittals to the docket, even though EPA has available data from other sources (e.g., NEI and TRI data).

If it could be ascertained that the available data were statistically representative of the entire subcategory (such that calculating the MACT floor with 12 percent of the number sources for which EPA received site-specific data would result in approximately the same value as the MACT floor using data from 12 percent of the entire subcategory), then the lack of data likely would not significantly skew the results. However, the Reconsideration Proposal and supporting documentation provide no assurance that the limited available data from a fraction of the sources in a category or subcategory are representative of the entire source category or subcategory. As a result, ACC believes that the lack of available data has produced MACT floors that are not being set by the best performing sources in a category or subcategory and are not reflective of the category or subcategory as a whole.

In some cases, EPA has augmented available stack test data with calculated emission factors in order to increase the number of sources on which the MACT floor is based (e.g., liquid fired boilers for which fuel data or stack test data from an identical boiler at the site are available). EPA should expand this approach by obtaining emissions data from all boilers in a subcategory, whether by obtaining additional fuel data, additional stack test data, or estimating emissions for these boilers based on available emission factors. In fact, EPA has estimated emissions for all of the boilers being regulated under the MACT in order to quantify the expected emissions reductions of the Final Boiler Rule. Therefore, EPA should be using data from the top 12 percent of the total number of boilers in each subcategory in order to set limits, not 12 percent of the sources for which it has received stack test or fuel analysis data. EPA is using this approach in the CISWI rule.

The following tables demonstrate the disparity between the amount of data currently being used to set standards and the actual percentage of boilers in each subcategory that are being represented by each floor (assumes EPA has properly subcategorized units). ***EPA has not used 12 percent of the number of existing sources to set floors in any subcategory that has more 30 or more sources.***

Subcategory	**Parameter**	**Mercury**	**HCl**
Solid	Number of sources in subcategory	1,118	1,118
	Number of sources EPA is using to set limits	323	368
	Number of sources in EPA floor	39 (3.5%)	45 (4.0%)
	Number of sources that represent 12% of subcategory	135	135
Liquid	Number of sources in subcategory	901	901
	Number of sources EPA is using to set limits	71	84
	Number of sources in EPA floor	10 (1.1%)	11 (1.2%)
	Number of sources that represent 12% of subcategory	109	109
Gas 2	Number of sources in subcategory	129	129
	Number of sources EPA is using to set limits	1	1
	Number of sources in EPA floor	1 (0.8%)	1 (0.8%)
	Number of sources that represent 12% of subcategory	16	16

Subcategory	**Parameter**	**CO**	**PM**
Coal – Stoker	Number of sources in subcategory	391	391
	Number of sources EPA is using to set limits	46	182
	Number of sources in EPA floor	6 (1.5%)	24 (6.1%)
	Number of sources that represent 12% of subcategory	47	47
Coal – FB	Number of sources in subcategory	35	35

Subcategory	Parameter	CO	PM
	Number of sources EPA is using to set limits	16	24
	Number of sources in EPA floor	2 (5.7%)	4 (11.4%)
	Number of sources that represent 12% of subcategory	5	5
Coal - PC	Number of sources in subcategory	190	190
	Number of sources EPA is using to set limits	37	106
	Number of sources in EPA floor	2 (1.1%)	14 (7.4%)
	Number of sources that represent 12% of subcategory	23	23
Biomass – Dry Stoker	Number of sources in subcategory	74	74
	Number of sources EPA is using to set limits	6	4
	Number of sources in EPA floor	1 (1.4%)	1 (1.4%)
	Number of sources that represent 12% of subcategory	9	9
Biomass – Wet Stoker	Number of sources in subcategory	305	305
	Number of sources EPA is using to set limits	83	103
	Number of sources in EPA floor	11 (3.6%)	14 (4.6%)
	Number of sources that represent 12% of subcategory	37	37
Biomass – FB	Number of sources in subcategory	24	24
	Number of sources EPA is using to set limits	6	9
	Number of sources in EPA floor	5 (20.8%)	5 (20.8%)
	Number of sources that represent 12% of subcategory (or 5 if number in subcategory <30)	5	5
Biomass – Suspension Burner	Number of sources in subcategory	47	47
	Number of sources EPA is using to set limits	6	4
	Number of sources in EPA floor	1 (2.1%)	2 (4.3%)
	Number of sources that represent 12% of subcategory	6	6

Subcategory	Parameter	CO	PM
Biomass – Dutch Oven/Pile Burner	Number of sources in subcategory	23	23
	Number of sources EPA is using to set limits	13	11
	Number of sources in EPA floor	4 (17.4%)	5 (21.7%)
	Number of sources that represent 12% of subcategory	3	3
Biomass – Fuel Cell	Number of sources in subcategory	15	15
	Number of sources EPA is using to set limits	7	10
	Number of sources in EPA floor	5 (33.3%)	5 (33.3%)
	Number of sources that represent 12% of subcategory (or 5 if number in subcategory <30)	5	5
Heavy Liquid	Number of sources in subcategory	320	320
	Number of sources EPA is using to set limits	17	32
	Number of sources in EPA floor	3 (0.9%)	4 (1.3%)
	Number of sources that represent 12% of subcategory	39	39
Light Liquid	Number of sources in subcategory	581	581
	Number of sources EPA is using to set limits	59	24
	Number of sources in EPA floor	8 (1.4%)	3 (0.5%)
	Number of sources that represent 12% of subcategory	70	70
Gas 2	Number of sources in subcategory	129	129
	Number of sources EPA is using to set limits	2	5
	Number of sources in EPA floor	1 (0.8%)	1 (0.8%)
	Number of sources that represent 12% of subcategory	16	16

b. EPA Is Justified In Using Emissions Data From Five Sources To Determine The Existing Source MACT Floor For Subcategories With More Than 30 Sources Where Emissions Information On Less Than 30 Sources Are Available

The above tables point out that in several cases, EPA is using less than 5 sources to set MACT floors. EPA has explained that it is using the top 12 percent of sources for which data are available where there are more than 30 sources in a subcategory. EPA should use no fewer than 5 sources in setting the MACT floor for any source category – regardless of the number of sources in the category or subcategory. The language of § 112(d)(3)(A) shows that Congress clearly expected enough emissions information to be available for categories or subcategories with 30 or more sources so that more than 5 sources would be used in selecting the top 12%. It makes no sense for Congress to specify a minimum number of sources, i.e. 5, for source categories or subcategories with less than 30 sources, but allow EPA to establish standards based on less than 5 sources for larger source categories. Using no less than 5 sources at all times would comport with the clear intention of Congress.

ACC also notes that the word "sources" as used in the last clause of §§ 112(d)(3)(A) and (B) is ambiguous and, therefore, susceptible to reasonable interpretation by the Agency. As EPA explains in the preamble, the word "sources" might be construed to refer to <u>all</u> sources in the given category or subcategory. However, the word "sources" in the first clause of §§ 112(d)(3)(A) and (B) clearly refers to the sources for which EPA has emissions information. Notably, the second use of the word "sources" in § 112(d)(3)(A) also clearly is a reference to sources for which EPA has emissions information. So, it is reasonable to conclude that Congress intended the word "sources" to have a consistent meaning for all purposes under these provisions. In other words, the reference "30 or more sources" at the end of § 112(d)(3)(A) and "fewer than 30 sources" at the end of § 112(d)(3)(B) reasonably should be construed as a reference to sources for which EPA has emissions information. This interpretation allows for EPA to naturally reconcile the application of §§ 112(d)(2)(A) and (B) such that the number of sources for which EPA has emissions information in a given category or subcategory dictates whether § 112(d)(2)(A) or (B) should apply.

c. *EPA Should Adjust its Procedures for Setting New Source Limits*

Some of the new source and existing source limits are the same (for example, the solid fuel HCl limit) because the 99 UPL for the new unit data is higher than the 99 UPL for the existing unit data. If the emissions data for the top performing unit exhibits more variability than the emissions data for the existing units then EPA cannot ignore this fact. It is arbitrary to choose the calculated existing unit limit as the standard that both types of units must meet. EPA should instead set both the existing and new unit standards at the calculated new unit UPL in order to adequately reflect variability and apply a defensible fuel variability factor to appropriately determine an achievable existing source emission limit recognizing the limitations of the floor determination process as indicated above.

G. TUNE-UP WORK PRACTICES

1. ACC Supports the Tune-Up Frequency Change for Small Units

EPA has proposed to change the frequency for tune-ups (following the initial tune-up) for gas and light liquid boilers and process heaters that are equal to or less than 5 MMBtu/hr to a tune-up once every 5 years. (76 Fed. Reg. 80614.) For new units, EPA has proposed to remove the requirement for the initial tune-up, considering that new units will likely be tuned during the initial startup process as part of commissioning. For facilities with a large number of small units, completion of tune-ups on a biennial basis can quickly become a logistics issue, due to the need to schedule periods where the boilers can be tuned without undue disruption to the operation of the facility. ACC believes that a tune-up every 5 years is appropriate for gas and light liquid units

5 MMBtu/hr or less in size, as emissions from these boilers are small, and allowing a reduced tuning frequency will reduce the cost of the rule. Therefore, ACC supports these changes, as they minimize the compliance burden for small units with minimal emissions impact.

2. *ACC SUPPORTS MODIFICATIONS TO TUNE-UP FREQUENCY AND PROCEDURES FOR VERY LIMITED USE UNITS*

EPA should also reconsider and modify the tune-up provisions for process heaters that operate on a very limited basis. The Reconsideration Proposal includes a requirement that a limited use process heater must conduct a tune-up biennially as specified in § 63.7540. Implementation of all of the tune-up requirements for process heaters that are operated on a very limited basis is problematic due to the few hours per year that some of these devices operate. In some cases, small start-up heaters run for about one hour at a time and they typically only run a handful of times a year at random times on an as needed and often unplanned basis. They are only and can only be used during a very limited time, i.e., startup of the process to pre-heat a process material prior to the reactor coming on line. Because of the shortness of this time period, it is not possible to optimize the system to reduce CO emissions and conduct CO emission screening before and after the adjustments. The Dow Chemical Company, an ACC member company, advocated in its comments that these limited use process heaters should only be subject to a recordkeeping requirement.[26] At a minimum, the tune-up requirements in §63.7540(a)(10) need to be modified to reflect the fact that the only element of the work practice that can be executed for these very limited use process heaters is § 63.7540(a)(10)(i) regarding burner inspections and replacements.

H. ENERGY ASSESSMENT

The definition of energy assessment proposed in this reconsideration, while improved from the language in the Final Boiler Rule, continues to be too broad because it appears to establish obligations beyond the boiler or process heater source. The rule states that an energy assessment, or audit, is an in-depth energy study identifying all energy conservation measures appropriate for a facility given its operating parameters. It leads to the reduction of emissions of pollutants through process changes and other efficiency modifications. The purpose of an energy assessment is to identify energy conservation measures (such as process changes or other modifications to the facility) that can be implemented to reduce the facility energy demand which would result in reduced fuel use.[27] 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.[28]

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

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[26] See Docket ID No. EPA-HQ-OAR-2002-0058-2632

[27] 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."

[28] See Table 3 to Subpart DDDDD and the definition of qualified energy assessor in §63.7575.

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.[29]

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

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.

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. ACC believes that EPA's intentions are to limit the scope of assessment based on energy use by discrete segments of a facility, and not by a total aggregation of all individual energy using elements of a facility, because the latter would be disjointed and unwieldy at best. The applicable discrete segments of a facility could vary significantly depending on the site and its complexity. However, ACC believes the following addition to the energy assessment definition in § 63.7575 would help resolve current problems and allow for more streamlined assessments:

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

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[29] 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.

I. AFFIRMATIVE DEFENSE PROVISIONS DURING MALFUNCTIONS

In the Final Boiler Rule, EPA for the first time stated that boilers and process heaters would be required to comply at all times with emission limitations derived from and established for normal operations, even during periods of malfunction. This is contrary to a long history of recognition by EPA and the courts that technology-based emission standards and requirements established in NESHAP and new source performance standard (NSPS) rules need to account for unavoidable excess emissions associated with malfunctions. EPA now chooses to disregard its historical position and instead proposes an "affirmative defense" that may be available to avoid civil penalties (but not other relief available under the CAA) for emission exceedances associated with malfunctions. The affirmative defense provisions appear in § 63.7501 of the final rule and require an owner/operator of a major source boiler or process heater to prove by a preponderance of evidence that it has met each and every requirement in order to avail itself of the affirmative defense to a claim for civil penalties. For the reasons discussed below, ACC believes that EPA should abandon the approach it is taking to addressing malfunctions, that is, offering an affirmative defense, and instead should use its statutory authority in § 112(h) to establish a work practice or operational standard that would reduce emissions during a malfunction event.

1. EPA'S APPROACH TO MALFUNCTIONS IS NOT REQUIRED BY SIERRA CLUB V. EPA AND IS CONTRARY TO THE REQUIREMENTS OF SECTION 112 OF THE CLEAN AIR ACT.

EPA states in the Final Boiler Rule that, "[c]onsistent with" the holding in *Sierra Club v. EPA*, 551 F. 3d 1019 (D.C. Cir. 2008), *cert. denied*, 130 S. Ct. 1735 (2010) ("*Sierra Club*"), it has established emission standards that apply at all times, even during a period of malfunction. 76 Fed. Reg. 15608, 15613. ACC believes that there are a number of flaws in this statement and in EPA's approach to malfunctions experienced by boilers and process heaters, rendering it contrary to the requirements of § 112 of the Clean Air Act. More specifically:

- EPA has misinterpreted the holding of *Sierra Club*;
- EPA failed to consider malfunctions in establishing MACT numeric emission standards;
- EPA failed to present any rationale or justification for its decision to apply the same numeric emission standard established for normal operations during an abnormal event, i.e., a malfunction;
- EPA's inclusion of an affirmative defense is not a substitute for establishing a § 112-compliant standard for malfunction events; and
- EPA's affirmative defense requirements are potentially unconstitutional, but certainly unreasonable and not consistent with § 112.

a. EPA has Misinterpreted the Holding In Sierra Club.

As noted above, EPA believes that requiring sources to comply with numeric emission standards established for normal operations even during a malfunction event, is "consistent with *Sierra*

Club v. EPA." The D.C. Circuit's *Sierra Club* decision does not, however, compel or even support EPA's position that the same numeric standards established for normal operations must also apply during a malfunction event.

The *Sierra Club* ruling vacated the exemption for excess emissions during periods of startup, shutdown and malfunction (SSM) contained in the General Provisions, 40 C.F.R. part 63 subpart A, for emission standards for hazardous air pollutants regulated under CAA § 112. At issue was EPA's determination that excess emissions during periods of SSM experienced by major sources are not violations as long as the owner/operator has prepared a startup, shutdown and malfunction plan and complies with a "general duty" to minimize emissions. The court concluded that the "general duty" was not a "section112-compliant standard." However, the court did not state nor even imply that the same emission limits that EPA establishes for normal operations must apply during SSM events.

In fact, the court clearly indicated that section 302(k)'s "inclusion of [the] broad phrase" "any requirement relating to the operation or maintenance of a source to assure continuous emission reduction" in the definition of "emission standard" suggests that EPA can establish MACT standards consistent with CAA section 112 "without necessarily continuously applying a single standard." 551 F.3d 1019, 1021. The court accepted that "continuous" for purposes of § 302(k) "does not mean unchanging...." *Id.* at 1021. The court also highlighted the fact that Congress recognized that it might not be feasible in all cases to prescribe or enforce a numeric emission standard. Congress therefore provided in § 112(h) for the establishment of a "work practice" or "operational standard." *Id.* at 1028.

EPA is now soliciting comments on its determination in the final rule that boilers and process heaters must meet the numeric emission standards established for steady-state operations at all times, including periods of malfunction, and that the only enforcement relief that may be available in the event of a malfunction is an "affirmative defense" to civil penalties. EPA is completely silent on why it is not exercising the discretion and authority provided by Congress in § 112(h) to address boiler and process heater malfunctions; in fact, it does not even mention that statutory authority in discussing malfunctions. If EPA wants to act "consistent with" the court's decision in *Sierra Club,* it should promulgate standards for periods of malfunction pursuant to its § 112(h) authority. If EPA chooses to reject the flexibility that Congress clearly intended the Agency to use when it is not feasible to prescribe or enforce a numeric emission standard, it needs to explain its legal authority for these affirmative defense requirements and why each of the requirements is reasonable and justified, taking into consideration alternative solutions.

b. EPA Failed to Consider Malfunctions in Establishing MACT Numeric Emission Standards.

Under CAA § 112(d)(2), MACT emission standards must be "achievable." Moreover, when EPA establishes emission standards for existing sources based on the "best performing 12% of units in the category" (the "MACT floor"), those emission standards must on average be "achieved" by the best performers. *See*, § 112(d)(3). If EPA is going to require sources to meet a numeric standard at "all times" then the Agency must demonstrate that the standard accommodates the variability in emissions experienced, i.e., "achieved", by best performing sources "at all times", which would have to take into account, among other things, a potential malfunction.

Based on our review of documents in the docket for this rulemaking it appears that EPA did not consider any data identifying the level of HAP emissions that may result when a best performing source experiences a malfunction. EPA therefore has failed to show that HAP emission numeric limits that apply at all times reflect the reductions that are "achieved" by best performing sources during a malfunction.

Despite the fact that EPA and the courts historically have recognized the inherent limits of technology based standards in promulgating standards under both the Clean Air Act and the Clean Water Act, in this rule EPA chooses to ignore the fact that, despite an owner/operator's best efforts, technology sometimes fails and that even a best performing source could experience a malfunction.[30] Because EPA failed to consider the level of emissions that may result from a malfunction and incorporate that consideration in the numeric emission limitations, which apply at all times (other than during startup and shutdown), EPA's actions are arbitrary and capricious and not in accordance with law.

Furthermore, EPA's failure to establish emissions standards consistent with § 112 of the CAA also raises the issue of denial of due process. By establishing standards that are not attainable "at all times," EPA is subjecting thousands of boilers and process heaters to potential penalties and worse for failing to comply with numeric emission standards that are unattainable during a malfunction.

c. EPA Failed To Present Any Rationale or Justification for its Decision To Apply the Same Numeric Emission Standards Established for Normal Operations for an Abnormal Event, i.e., A Malfunction.

As highlighted above, the court in *Sierra Club* did not state that EPA must apply the same standards it establishes for normal operations during periods of SSM. The court's holding is clear that "some" § 112 standard must "govern" SSM events but it did not specify which § 112 standard. In this rulemaking, EPA concluded that the numeric emission limitations established for normal operations also must be attained during a malfunction event. However, EPA has provided no explanation as to why it believes that boilers and process heaters reasonably could

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[30] See 40 C.F.R. § 60.8(c). For example, the D.C. Circuit recognized, in *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 398 (D.C. Cir. 1973), a decision reviewing standards under CAA section 111, that "'start-up' and 'upset' conditions due to plant or emission device malfunction, is an inescapable aspect of industrial life and that allowance must be made for such factors in the standards that are promulgated." *Id.* at 399. Similarly, in *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 432 (D.C. Cir. 1973), *cert. denied,* 416 U.S. 969 (1974), another section 111 case, the court held that SSM provisions are "necessary to preserve the reasonableness of the standards as a whole." *Id.* at 433. In *National Lime Ass'n v. EPA*, 627 F.2d 416 (D.C. Cir. 1980), another case reviewing emission standards promulgated under CAA section 111, the court held that the CAA requirement that NSPS be "achievable" means that the standards must be capable of being met "on a regular basis," including "under most adverse circumstances which can reasonably be expected to recur," including during periods of SSM. 627 F.2d at 431 n.46. See also *Marathon Oil Co. v. EPA*, 564 F.2d 1253, 1273-74 (9th Cir. 1977); *NRDC v. EPA,* 859 F.2d 156, 207-208 (D.C. Cir. 1988) (similar conclusion when considering analogous Clean Water Act requirements).

be expected to meet the emissions standards applicable to steady-state operations during a malfunction event.

EPA claims that it somehow "presents significant difficulties" to attribute malfunctions to a "best performing" source. *Id.* To the contrary, it "presents significant difficulties" when EPA ignores the undisputed existence of malfunctions even at best-performing sources, and claims falsely that the best-performing sources "achieve" emission levels that they undisputedly do not achieve part of the time. Since EPA describes malfunctions as being sometimes unavoidable or "not reasonably preventable," despite proper design and maintenance of equipment, there is no basis for EPA's conclusion that malfunction events are not representative of best-performing sources. See 76 Fed. Reg.15613. True, one goal (although not "*the* goal") "of best performing sources is to operate in such a way as to avoid malfunctions of their units." *Id.* But that is all the more reason why EPA must acknowledge the fact that those sources nevertheless experience malfunction events, rather than pretend otherwise. Moreover, EPA should look to the "best performing" sources to establish the appropriate § 112(h) work practice standards for a malfunction event. After all, a work practice standard like a numeric emission standard must be based on the emission reductions achieved by the best performing sources.

In failing to articulate the basis for its decision, the Agency also ignores the comments submitted by ACC and others strongly advocating for EPA to establish a work practice standard for malfunction events. This is not reasoned decision-making and ACC hopes that the Agency's "reconsideration" of its affirmative defense approach will prompt EPA to give reasonable consideration to the fact that a boiler that has a malfunction is not likely to be able to achieve the same level of emission reductions that it achieved and can achieve while operating at steady-state.

d. EPA's Inclusion of an Affirmative Defense Is Not a Substitute for Establishing a § 112-Compliant Standard for Malfunction Events.

ACC believes that EPA should either revise the numeric emission limitations in the rule so that they consider and reflect the variability of emissions resulting from malfunction events, or use its statutory authority to establish a §112 work practice or management standard applicable during a malfunction event. There is no language in § 112 that authorizes EPA to offer an owner/operator an "affirmative defense" to civil penalties to cure the fact that it has finalized numeric emission standards that do not represent the emission levels actually "achieved" by the best performing sources "at all times". Moreover, EPA's offering of an affirmative defense does not bear a reasonable relationship to the purpose of § 112 or its requirement to establish standards that consider and address the reality of a potential malfunction of technology. If EPA chooses to reject the flexibility that Congress clearly intended the Agency to use when it is not feasible to prescribe or enforce a numeric emission standard, it needs to explain why its affirmative defense approach is a better alternative than using the statutory authority provided in § 112(h) to establish a work or management practice for a malfunction period.

EPA asserts that "it is reasonable to interpret section 112(d) as not requiring EPA to account for malfunctions in setting emissions standards." 76 Fed. Reg.15613. EPA offers little support for that assertion, however, other than stating its own, often counterintuitive, conclusions. For example, EPA says it "has determined that malfunctions should not be viewed as a distinct operating mode and, therefore, any emissions that occur at such times do not need to be factored into development of CAA section 112(d) standards, which, once promulgated, apply at all times." *Id.* EPA provides no explanation for why it "believes" that malfunctions are not a distinct operating mode. Moreover, EPA offers no explanation of its contradictory position that, even though it believes malfunctions are not a distinct operating mode, emissions during malfunctions should not be used to characterize the source's operating mode. On its face, asserting that malfunctions are part of normal operations, but then excluding emissions during malfunctions when determining emission limitations for normal operations, makes no sense.[31]

EPA's statement that "nothing in section 112(d) or in case law requires that EPA anticipate and account for the innumerable types of potential malfunction events in setting emission standards," *id.*, has it backwards. There is nothing in CAA § 112 that allows EPA to ignore malfunctions and set MACT standards—which are supposed to represent the performance actually achieved by the MACT "floor" sources—based on a level of emissions that even these best-performing sources only achieve part of the time.

EPA cannot rationally defend its view that applying the concept of "best performing" is somehow inconsistent with a source experiencing a malfunction. See 76 Fed. Reg.15613. This ignores that there are work practices – such as monitoring operating parameters to identify a malfunction and stopping or cutting back the process accordingly – that represent the best practices for minimizing emissions during a malfunction. While the measures that represent these best practices will depend on facility-specific issues, such as process design, pollution control train, and other factors, they nonetheless represent the "the maximum degree of reduction in emissions of the hazardous air pollutants...achievable...through application of measures, processes, methods, systems or techniques" and reflect "the emission control that is achieved in practice by the best controlled similar source[s]" CAA § 112(d)(2) and (3).

2. *EPA'S AFFIRMATIVE DEFENSE REQUIREMENTS ARE UNREASONABLE AND NOT CONSISTENT WITH § 112.*

The affirmative defense regulatory language in § 63.7501 opens with the words "*In response to an action to enforce* the emission limitations and operating limits set forth in…" and repeats this thought in paragraph (a) of the section: "To establish the affirmative defense *in any action to*

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31 The *Weyerhaeuser Co. v. Costle* decision EPA cites in the March 21, 2011 preamble, 590 F. 2d 1011 (D.C. Cir. 1978), does not support EPA's position. See 76 Fed. Reg. at 15613. In that case, the court was discussing a "technology forcing" standard, rather than one, like MACT, that is to be based on what is already being "achieved" or has been demonstrated to be achievable. Also, the SSM events that EPA acknowledges are expected to occur at sources subject to the MACT standards or boilers and process heaters are a far cry from the "'uncontrollable acts of third parties,' such as strikes, sabotage, operator intoxication, or insanity" that the Court was considering in the passage quoted by EPA, see *id.* Industry is not requesting that the emission standards provide relief from numerical emission limitations during those unusual types of events. Perhaps most importantly, the *Weyerhaeuser* decision came long before *NRDC v. EPA,* 859 F.2d 156 (D.C. Cir. 1988) which, as noted above, affirmed the need for an upset provision to address circumstances where compliance with effluent limitations is impossible through no fault of the permittee.

enforce such a limit…" (emphasis added). This opening language leaves a regulated party to believe that *if* any action is taken against that party to enforce an emission limit exceeded during a malfunction, the party may avail itself of an affirmative defense if it meets various criteria. However, this is not the way this would play out.

In § 63.7501(b) EPA establishes strict notification requirements that must be followed for the owner/operator to be able even to raise an affirmative defense if and when an enforcement action is brought. First, the owner/operator must notify EPA by phone or FAX as soon as possible, but no later than two business days after the "initial occurrence of the malfunction." Then, within 45 days of the "initial occurrence of the initial occurrence of the exceedance of the standard," the owner/operator must submit a written report accompanied by all necessary supporting documentation to show that it has met each and every requirement set forth in paragraph (a) of § 63.7501. Because of these short time frames, the reality is that EPA is requiring the facility to present its entire detailed defense in writing to EPA before EPA has even decided whether to take any enforcement action. To require a party to lay out its entire defense to a *potential* future enforcement action *before* that action may be taken is wholly inappropriate and unacceptable

EPA has cited no legal authority for its use of affirmative defense requirements that inappropriately and unlawfully shift the burden to the facility to prove by a preponderance of the evidence that any excess emissions were caused by a true malfunction *and* that the facility meets all of the other specified factors in § 63.7501. EPA's affirmative defense places the facility in the position of proving its innocence, rather than EPA or other regulatory authority proving that the facility violated the CAA.

EPA states that the affirmative defense may be raised to a "claim for civil penalties" but does not define "civil penalties". It is unclear, for example, whether this claim is meant to include a "civil administrative penalty" imposed by EPA under § 113(d) of the CAA? A "noncompliance" penalty sought under § 120 of the CAA? A "civil penalty" imposed by a court?

It is also unclear how the affirmative defense would apply to enforcement actions by state and local governments, or to private citizen enforcement actions brought under § 304 of the CAA. While in no way endorsing EPA's affirmative defense provision, ACC believes that if retained by the Agency after reconsideration, the provision should clearly state that it is applicable to *any* enforcement action.

Section 63.7501 states: "The affirmative defense shall not be available for claims for injunctive relief." The preamble is silent as to why the affirmative defense would not apply to injunctive relief. If the facility meets the requirements of the affirmative defense provision, why may it not be raised as a defense to a claim for injunctive relief? EPA's assertion to the contrary is unsupported by any explanation.

Turning to the individual requirements in § 63.7501(a)(1) through (9) that a facility must meet to be allowed to raise an affirmative defense, a number of these requirements are not relevant to whether a "malfunction", as defined in 40 CFR 63.2 occurred.

> *Malfunction means any sudden, infrequent, and not reasonably preventable failure of air pollution control and monitoring equipment, process equipment, or a process to operate*

> *in a normal or usual manner which causes, or has the potential to cause, the emission limitations in an applicable standard to be exceeded. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.*

Most of the conditions for establishing an affirmative defense in § 63.7501 may be relevant to determining whether the facility undertook appropriate and necessary measures to mitigate any excess emissions resulting from the specific malfunction, but do not in any way inform a determination of whether a piece of equipment has met the definition of a malfunction. For example, § 63.7501(a)(2) requires that "off-shift and overtime labor, to the extent practicable" were used to make the repairs needed. ACC fails to understand how this requirement relevant to determining whether a piece of equipment has "malfunctioned". See also (a)(3), (a)(5), (a)(6), (a)(7). (a)(8) and (a)(9).

A number of the requirements are extremely subjective and fail to allow for consideration of reasonableness or cost-effectiveness. For example, § 63.7501(a)(1)(ii) requires the owner/operator to show that the malfunction could not have been prevented through "careful planning," "proper design" or "better operation and maintenance practices." This subjective requirement leaves open the possibility that an enforcement official could always find actions that "could" have been taken without any consideration of costs, resources or feasibility. Moreover, it fails to consider that an owner/operator may have chosen to redesign a process or equipment configuration, or make other adjustments to achieve the emission reductions necessary to comply with the standard. In so doing, the owner/operator would have evaluated various options to determine which one was the most cost-effective approach to achieve the emission standard, keeping in mind that cost-effectiveness would include long-term safe and proper operation of the equipment or process. If a malfunction were to occur, it could be difficult if not impossible for the owner/operator to prove that the malfunction "could not have been prevented" if cost and resources were never an issue.

Another subjective and particularly problematic requirement is (a)(8) which requires that: "At all times, the *facility* was operated in a manner consistent with good practices for minimizing emissions." ACC strongly objects to EPA reaching beyond the *equipment* that malfunctioned to require a party to prove by a preponderance of the evidence that "at all times, the *facility* was operated in a manner consistent with good practices for minimizing emissions." (Emphasis added.) First, EPA does not define "facility" or "affected facility" in the final major source boiler rule, nor is it included in the definitions at 40 CFR 63.2; common usage of the term facility suggests that it means the entire plant.[32] Second, and more importantly, EPA is requiring a party to comply with a requirement that is ambiguous, highly subjective, and therefore impossible to satisfy. This is not reasoned decision-making. ACC notes that in its proposed reconsideration of various provisions of the Chemical Manufacturing Area Source Rule ("CMAS"), EPA has

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[32] The term "affected facility" is used in NSPS and is defined in the NSPS General Provisions at 40 CFR 60.2, but the MACT standards in Part 63 use the term "affected source," and the definition of affected source in 40 CFR 63.2 states: "Affected source may be defined differently for part 63 than affected facility and stationary source in parts 60 and 61, respectively." EPA does define the "affected source" in § 63.7490(a) ("the collection at a major source of all existing industrial, commercial, and institutional boilers and process heaters within a subcategory" or "each new or reconstructed industrial, commercial, or institutional boiler or process heater...located at a major source").

revised this requirement and changed the word "facility" to "affected source." (77 Fed. Reg. 4522, January 30, 2012.) If the affirmative defense provision is included in the final reconsidered boiler major source rule, EPA should follow what it has done in CMAS and change "facility" to a more appropriate and defined term, such as "affected source."

Requirement (a)(4) would disallow the affirmative defense if a malfunction involved bypassing control equipment or a process, and the bypass was not taken "to prevent loss of life, severe personal injury, or severe property damage." This language is both unyielding and subjective. It is unyielding in that it fails to allow any consideration of the fact that bypassing the control equipment or the process may have been an appropriate exercise of good air pollution control practices. For example, a bypass can constitute the best air pollution control practice in response to an upset in order to prevent excess emissions, e.g., to avoid fouling of pollution control equipment media that in turn would result in reduced pollution control equipment efficiency or increased pollution control equipment downtime. Additionally, in some cases the air emissions from a venting event are lower than if the facility had an uncontrolled shutdown to avoid venting. An uncontrolled shutdown could also impact other media, e.g., a wastewater dump from scrubbers, solid waste, etc. And, a shutdown would necessitate additional startup emissions. Arguably, venting for a short period due to malfunction could result in less emissions than a non-orderly shutdown and subsequent restart. Yet, as worded, this requirement would discourage an owner/operator from taking the less-impactful option because it would mean that he could not avail himself of an affirmative defense for the malfunction.

This requirement is subjective in its use of the word "severe." Reasonable minds could disagree on what constitutes "severe" property damage, or "severe" personal injury. Lastly, this requirement is not supported by any explanation as to why "bypassing" control equipment or a process is absolutely unacceptable except when an owner/operator is faced with these dire consequences.

Requirement (a)(5) demands that a party prove that: "All possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment and human health." Again, the subjectivity of "all possible steps" is problematic in that it establishes a potentially unattainable standard with no clear direction as to how a party is to meet it.

Requirement (a)(9) is problematic in that it requires a party to prepare a "written root cause analysis to determine, correct and eliminate the primary causes of the malfunction and the excess emissions resulting from the malfunction event at issue." This directive assumes that the cause of any and all malfunctions can be determined, corrected and eliminated. If a malfunction by definition is unavoidable, unforeseeable, and not reasonably preventable, it may be that the first time it happens its primary cause cannot be determined. If the cause cannot be determined, it cannot be corrected. So unless a party can figure out why something malfunctioned, it cannot claim to have had a "malfunction." Not only is this nonsensical, it is a significant departure in EPA policy with no justification provided. For example, in the General Provisions applicable to New Source Performance Standards (NSPS), EPA recognizes that the cause of a malfunction cannot always be known. *See,* 40 CFR 60.7(b)(2) which requires that written reports of excess emissions include the "nature and cause of any malfunction, *if known*…." (Emphasis added.) Lastly, requiring a party to eliminate the primary causes of the malfunction, without regard to "taking into consideration the cost of achieving such" elimination and the "non-air quality health and environmental impacts and energy requirements" associated with its elimination is unreasonable and entirely inconsistent with the criteria for standards established under § 112(d) of the CAA.[33]

Turning to the 2-day notification requirement in § 63.7501(b), ACC notes that EPA recently proposed almost identical affirmative defense requirements in the CMAS proposed reconsideration but omitted the 2-day notification. It is ACC's understanding that the Agency has been persuaded by comments submitted by ACC and others that the 2-day notification requirement is onerous and burdensome. ACC also understands that EPA may be revisiting some of the other requirements in the affirmative defense provisions in order to further reduce the burden on facilities, and therefore request that in its reconsideration EPA abandon the 2-day notification requirement in the final provisions for major source boilers and process heaters.

Unlike the 2-day notification which is triggered by the "initial occurrence of the malfunction," the 45-day period for submitting a written report demonstrating that the party qualifies for the affirmative defense commences on the date of "the initial occurrence of the exceedance of the standards." Complying with this timeframe presents several challenges, specifically because most of the content of the report may not be able to be created until the malfunction has ended, which in some cases could be a number of days.

While there is an opportunity for requesting and obtaining an extension of the reporting deadline of up to 30 additional days, the owner/operator must comply with the original 45-day requirement unless and until he hears back from EPA that the extension request is approved. However, there is no requirement for EPA to act timely in granting or denying an extension request. At a minimum, the rule should provide a timeframe within which EPA must act on a request and if it fails to do so, the request would be considered granted.

For all of the reasons above, and in keeping with the court's holding in *Sierra Club*, ACC strongly encourages the Agency to abandon its affirmative defense approach as an appropriate and legal way to address excess emissions during a malfunction, and instead to use its authority in § 112(h) to establish an emission standard using a management practice, work practice or operational standard to reduce emissions during a malfunction of a boiler or process heater.

J. WORK PRACTICES DURING STARTUP AND SHUTDOWN

ACC provided extensive support for establishing work practices for periods of startup and shutdown in our comments on the 2010 Proposed Boiler Rule.[34] Our key points supporting work practices for startup and shutdown periods were:

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[33] For example, it might be theoretically possible to eliminate the excess emissions associated with the malfunction by installing totally redundant pollution control equipment, or pollution control equipment with far more capacity than needed for normal operations. But this would not reflect the performance of the best performers on which the MACT "floor" is to be based, nor would it appear to take cost and other factors into consideration as the statute requires for beyond-the-floor MACT standards. Moreover, the proposed requirement to eliminate "the primary causes of the malfunction" and not just to eliminate "the excess emissions resulting from the malfunction event" lies entirely outside of EPA's authority under the CAA, which is limited to establishing and enforcing emission limitations, not dictating plant operations.

- The statute requires that the standards established under §112(d)(2) be "achievable." Sources cannot achieve the proposed numeric standards during periods of startup and shutdown in many cases.
- The D.C. Circuit also has recognized that standards based on what sources achieve must account for the limitations inherent in the technology used to reduce emissions. Certain air pollution control equipment (e.g., fabric filters and ESPs) cannot fully operate until certain boiler operating conditions are reached (e.g., appropriate stack gas temperature).
- EPA did not use any data obtained during periods of startup and shutdown in setting stack test-based standards.
- Sources cannot meet CO standards during low load and transient load periods.
- Safety concerns must be accommodated during startup and shutdown.
- Other recent MACT rules, such as the RICE MACT, incorporate work practices for startup and shutdown.

ICI boilers, like their larger EGU counterparts, require an extended period of startup during which most, if not all, equipment in the boiler and pollution control systems are not operating in their normal condition. This extended startup period, which can range from a few to many hours depending on unit design and emissions control systems in place, is required due to equipment integrity concerns, limitations of the technologies, or safety concerns.

Section 112(h) allows EPA to set work practice standards for situations where it is not feasible to prescribe or enforce an emission standard. Gathering data for pollutant emissions from startup and shutdown periods would be nearly impossible given the brief nature of these periods, as well as the need to define the exact time period for what is considered "startup" and/or "shutdown," and the fact that most reference methods are not designed for non-steady state conditions and would not perform well during these periods. Moreover, the definition of "not feasible to prescribe or enforce an emission standard" is defined in §112(h) as any situation where "the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations."

Startup, shutdown, and malfunction events fit perfectly within this definition for the reasons outlined above and justify establishing work practices to address emissions during these periods. Furthermore, a work practice approach for these periods would be in keeping with the statute's requirement that MACT standards be "achievable" as well as with the underlying requirement that a standard apply at all times.

EPA has proposed to expand upon the work practice requirements in the Final Boiler Rule by adding specific requirements to employ good combustion practices, train operators on proper startup and shutdown procedures, and maintain records (see Table 3 item 5 of the reconsidered rule). ACC agrees that these are appropriate requirements. ACC also agrees with the clarification EPA has made to Table 2 to indicate that emission limits do not apply during periods of startup and shutdown, as work practices and not numeric emission standards apply during these times as provided in § 63.7540(d).

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[34] See Docket ID EPA-HQ-OAR-2002-0058-2792.

EPA requests comment on whether a maximum time should be included in the startup and shutdown definitions. ACC believes that this is not necessary, as safety and proper operation of the boiler and associated equipment dictate the amount of time that is needed for startup and shutdown and vary from unit to unit and site to site. Overly prescriptive and non-facility-specific requirements can actually be counterproductive, restricting the operators' flexibility in a way that hampers their ability to troubleshoot or respond to an event, or that compromises safety.

EPA has included a threshold of 25 percent load in its definition of startup and shutdown. Some units have a minimum stable operating load that is higher than 25 percent (e.g., stable operation for a stoker boiler may not be reached until 60 percent load). Therefore, EPA should revise the startup definition to allow facilities to determine the minimum stable operating load on a unit-specific basis and include the minimum stable operating load that defines startup and shutdown and the proper procedures to follow during startup and shutdown in a site-specific plan.

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

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

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

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

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

However, ACC does believe that if the startup and shutdown definitions are finalized with a load threshold, EPA should provide clarity for what requirements units operating in standby mode at loads less than that threshold (e.g., 25 percent) must meet. ACC believes that work practices are appropriate for units operating in standby mode at very low load. Boilers or process heaters operating in a standby mode would typically be combusting clean burning liquid or gaseous fuels during those periods.

EPA also requests comment on whether sources should be required to use specific fuels during periods of startup and shutdown. Not all facilities are permitted for or have access to sufficient natural gas or other lower-emitting fuels to be able to use it as their startup fuel, and not all units are capable of burning natural gas or distillate oil. Specifying the use of natural gas or distillate fuel oil would also result in increased capital and operating costs for many facilities; these fuels are in many cases more expensive than a unit's primary operating fuel and require different infrastructure to accommodate, if they can even be made available.

K. APPLICABILITY

1. Exemptions for Units Serving as Control Devices

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

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

EPA could specifically revise proposed § 63.7491(h) to include the combustion units, combustion unit exhaust streams, and process vent gas streams covered under another MACT as follows:

> *§63.7491(h) Any boiler, process heater, combustion unit, combustion unit exhaust stream, or process vent gas stream that is specifically listed as an affected source in another standard(s) under 40 CFR part 63.*

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

2. *Waste Heat Boilers and Process Heaters*

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

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

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

3. *Units Firing Comparable Fuels*

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

L. COMPLIANCE

1. *Extending Compliance Dates*

EPA proposes to reset the compliance deadline for existing sources to 3 years from the effective date of the final reconsidered boiler major source rule. For new sources, EPA proposes to reset the compliance date to 60 days after promulgation of the final reconsidered rule.

EPA clearly has authority to reconsider and revise standards pursuant to §307 of the Clean Air Act. After such reconsideration and revision to the standards, "there will be circumstances where EPA changes a rule so extensively that the amended rule should be regarded as a new standard."

Pesticide Active Ingredient (PAI) NESHAP, 67 Fed. Reg. 38200, 38201 (June 3, 2002). Sources need time to come into compliance with such "new standards." *Id.*

Section 112(i)(3)(a) gives EPA the flexibility to allow existing sources up to 3 years to meet "any emissions standard". As noted above, EPA used this authority in the revised PAI rule to establish a new compliance deadline for existing sources that was an additional 16 months from the deadline in the original final rule. *Id.* EPA took similar action in establishing a new compliance deadline after reconsideration and promulgation of revised standards in the Miscellaneous Organic Chemicals Manufacturing (MON) NESHAP, 71 Fed. Reg. 10439, 10440 (Mar. 1, 2006).

EPA's reasoning in extending/resetting the compliance deadline in both the PAI and the MON is equally applicable to this rulemaking. In those NESHAP rules, EPA reasoned that § 112(i)(3) is ambiguous as to whether an initial compliance date applies to a rule that has been substantially revised. EPA asserted, and in the case of the MON ACC concurred in comments, that when provisions of a rule are changed to such a degree that the amended rule triggers a new effective date, this is a new "emission standard" requiring a new compliance deadline. Additionally, § 112(d)(6) requires EPA to review and if necessary revise § 112 standards no less than every 8 years. If the underlying standard is revised, it is axiomatic that a new compliance deadline would have to be established to allow sources to come into compliance with the revised rule.

The need for EPA to reset the compliance deadline in this rulemaking is all the more compelling because of some unique circumstances:

First, EPA administratively stayed the rule on May 18, 2011, two days before the rule was to become effective. See, 76 Fed. Reg. 28662 (May 18, 2011). EPA stayed the rules because it had already determined that significant requirements of the rule needed to be reconsidered and needed additional public comment. Additionally, the Agency received a number of petitions for reconsideration from interested parties, including ACC, asking the Agency to reconsider additional provisions. That stay remained in place until January 9, 2012, when it was vacated by a federal district court. *Sierra Club v. EPA*, No. 11-1278-PLF, 2012 U.S. Dist. LEXIS 2457, (D.D.C. Jan. 9, 2012).

Second, due to the vacatur of the stay, the regulated community has lost almost a year from the original compliance time frame. If EPA does not reset or extend the compliance date in the final reconsidered boiler major source rule, affected sources will have only about two years to undertake all of the actions and testing required to try to meet the existing compliance deadline. Given the complexity of this rule and all of the necessary actions that thousands of affected sources will have to take, meeting a 2 year compliance deadline is going to be impossible for most sources, even if the final reconsidered rule were to remain unchanged from the March 2011 final rule.

Third, exacerbating the compliance challenges that will be presented in the final reconsidered rule is the fact that EPA is promulgating the first NESHAP rule applicable to EGUs along the same time frame as this rule. As EPA correctly notes, the sheer volume of sources that will need to devise new compliance strategies and install new equipment pursuant to this rulemaking, the

CISWI rulemaking, and the EGU rulemaking will outstrip the availability of the vendors who can do this work. 76 Fed. Reg. 80616.

Under the best of circumstances, a major retrofit of a boiler takes years from project start to finish. EPA has estimated that the installation of an activated carbon injection control system on one combustion unit – a comparatively simple installation – takes about 15 months.[35] However, EPA expects a range of control devices will be used to meet the standards, including fabric filters, activated carbon injection, electrostatic precipitators, wet scrubbers, replacement burners, and combustion controls.[36] Further, the sheer number of boilers impacted by the rule will make finding – and then scheduling – the design and construction resources almost impossible. EPA estimates that there are approximately 14,111 units located at 1,704 facilities covered by this rule, and more than 2,000 of these units fire fuels other than gas. 76 Fed. Reg. 80622. Given that EPA has set emissions standards that only a small percentage of non-gas fired existing units can currently meet, almost every single existing unit subject to an emission standard will need to be retrofitted. Boiler owners will need to hire consultants to assist them in designing and performing the retrofit. Thus, across the multitude of industries impacted by this rule, boiler owners will be scrambling to find the very few qualified consultants who can perform the retrofits necessary to make boilers compliant with this stringent rule. There are a limited number of consulting companies with the expertise to assist in such retrofits, and they will likely be unable to assist all of the boiler owners in less than three years, especially when the electric utility industry will be competing for the same resources in order to comply with their own MACT standard. There will be a similar scarcity in equipment vendors, construction contractors, construction equipment (e.g., heavy lifting cranes), skilled labor (e.g., boilermakers), and other critical suppliers. Companies may even be unable to secure the basic building materials and control equipment (e.g., baghouses and scrubbers).

In order to retrofit a boiler, the owner will need to line up the capital necessary to pay for the retrofit. In these difficult economic times, just securing the necessary capital may take months, if not years, assuming the capital can be obtained from lending sources. In addition, the owner will need to go through the relevant permitting process(es), which will similarly take months, if not years. Finally, once the finances are secure and the permitting is complete, the owner will actually need to perform the retrofit. The design, procurement, installation, and shakedown of a retrofit project (e.g., installing a scrubber on a large boiler) can easily take more than three years. An example of a rulemaking that involved control retrofits over an extended compliance period is the implementation of the 1-hour ozone SIP requirements in Houston, Galveston, and Brazoria Counties in Texas. Due to the magnitude of the NOx emissions reductions required and the number of sources affected, emission reduction projects were implemented over a 6-year timeframe (2001-2007), with a total capital investment of over $3 billion. As the Boiler MACT

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[35] EPA, Engineering and Economic Factors Affecting the Installation of Control Technologies for Multipollutant Strategies (2002).
[36] EPA, Regulatory Impact Analysis: National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters, 3-1 (April 2010) ("The control analysis considered fabric filters, carbon bed adsorbers, and activated carbon injection to be the primary control devices for mercury control, electrostatic precipitators for units meeting mercury limits but requiring additional control to meet the PM limits, wet scrubbers to meet the HCl limits, tune-ups, replacement burners, and combustion controls for CO and organic HAP control….")

will involve more significant emission controls retrofits, it is appropriate to allocate a longer compliance timeframe.

In addition, the timing of the retrofit work needs to be carefully planned, particularly for boilers that provide the primary and/or base load energy supply for their facilities. A facility owner will only shut down a boiler when everything is properly staged to ensure minimal disruption of the facility's operation. In addition to ensuring that the design work is completed and the control equipment and other supplies are on-site and ready for installation, the facility owner needs to make sure that the full suite of consultants and laborers are available for the installation. Based on a discussions with a number of potentially affected companies, the turnaround or shutdown cycles for boilers and process heaters at many of the facilities can vary from 1 to 5 years, making this type of precise staging exceedingly difficult to do in a three year period without substantial business interruption.

Finally, in many instances, the installation of pollution control equipment and associated charges to boiler must be permitted under state air pollution statutes and/or construction codes (building permits, etc.). The proposed rule will result in an increase in the number of permit applications, potentially swamping the state and local agencies. Even in those areas where the rule may not result in significant increases in permitting work, the normal delays associated with permitting may make meeting the three year compliance deadline impossible.

In its lengthy discussion in the preamble to this Reconsideration Proposal, EPA has accurately highlighted most of the reasons why the compliance date needs to be revised in the final reconsidered rule. *Id.* ACC strongly supports the Agency providing the maximum compliance time frame allowed by the CAA for sources to come into compliance with a complex, costly and widely applicable rule.

In light of the difficulty in meeting a three year compliance deadline as explained above, EPA and authorized states should be prepared to readily grant one-year extensions under CAA § 112(i)(3)(B) to those units that have problems installing the necessary control equipment to comply with the final rule. EPA should also make clear in this rule, as it did in the MATS rule[37], that the 1-year extension also applies to repowering projects as they are applicable to ICI boilers and process heaters:

> *"The EPA took comment on whether the construction of on-site replacement power could be considered the "installation of controls" such that a fourth year would be available while the replacement unit is being completed for a unit that is retiring (e.g., a case when a coal-fueled unit is being shut down and the capacity is being replaced on-site by another cleaner unit such as a combined cycle or simple cycle gas turbine). After reviewing the comments, EPA believes that it is reasonable for permit authorities to allow the fourth year extension to apply to the installation of replacement power at the site of the facility. The EPA believes that building replacement power constitutes the "installation of controls" at a facility to meet the regulatory requirements."*

[37] 77 Federal Register 9410, February 16, 2012

2. *Reduced Testing Frequency and Detection Levels*

The Final Boiler Rule requires annual emissions testing (once every 13 months). See § 63.7515 (a). Facilities can conduct performance tests less often for a given pollutant if the performance tests for the pollutant for at least 2 consecutive years show that emissions are at or below 75 percent of the emission limit (or, in limited instances as specified in Tables 1 and 2, at or below the emission limit), unless they are using emissions averaging. See § 63.7515(b). While ACC does agree with EPA's acknowledgement of the need for reduced stack testing frequency for units with emissions below the standards, the requirement for initial annual stack testing and for ongoing annual stack testing where emissions averaging is being used is unreasonable and out of character with other MACT and NSPS standards and other state performance testing requirements.

EPA has proposed the most aggressive performance testing requirements of which we are aware on the largest MACT source category it has addressed to date. By contrast, the Hazardous Waste Combustor MACT (Subpart EEE) requires a comprehensive performance test only once every 5 years. Many MACT standards and NSPS only require one initial performance test unless there is a physical change to the control device that would increase emissions. The purpose of the initial performance test is to ensure that the technology installed is capable of meeting the emission limits. EPA has proposed extensive monitoring and recordkeeping that is meant to ensure continuous compliance with the emission standards. If these extensive monitoring and recordkeeping provisions are finalized, the frequency of stack testing should be reduced to once every 5 years.

3. *Fuel Analysis of Gaseous Fuels at Co-Fired Units*

ACC agrees with EPA's determination that no fuel analysis for chloride is required for gases and that operators are not required to conduct the mercury fuel specification analyses for gaseous fuels that are natural gas, refinery gas, or otherwise subject to another subpart of part 63.[38] EPA also should exempt those sources using process gases that otherwise are regulated under Parts 60 and 61 from conducting a fuel specification analysis. Specifically, § 63.7521(f)(2) should be amended with the addition of the bold language noted to read:

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

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

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

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[38] 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.

Additionally, ACC recommends EPA add Method 30B as an approved method for demonstrating that a gas fuel meets the specification for "Other Gas 1 Fuel" in Table 6 of the rule, or note that the method is "equivalent" to the listed methods. EPA Reference Method 30B was developed to determine the mercury content in exhaust gas streams associated with coal combustion. However, our members have indicated that external stack testing companies have successfully used this method to measure the mercury concentration in off-gas streams that are used as fuel in boilers and process heaters. External lab partners assure our members that Method 30B is superior and more accurate than any of the older methods that are currently listed in the rule. The method is also easier and safer to implement and conduct in the field since the other methods listed by EPA require an in-situ analysis of the fuel stream. Method 30B is designed to measure the mass concentration of total vapor phase mercury, including elemental mercury and oxidized forms of mercury in micrograms per cubic meter. The analytical range and sensitivity is typically in the range of 0.1 to 50 micrograms per cubic meter, which should be adequate to demonstrate that the mercury content is less than 40 micrograms per cubic meter.

4. Non-Detect Data

In setting limits under this rule, EPA has attempted to ensure that they are not set at less than 3 times a "representative detection limit" or RDL.[39] Therefore, EPA has not set out procedures for handling non-detect data obtained from fuel analyses or stack testing. The RDL was determined based on only the laboratory analysis data from the top performing units, and does not take into account the error associated with sampling procedures. ACC has not had adequate time to evaluate all of the limits against what our members typically experience as non-detect levels from the companies used by our members. However, ACC requests that EPA include a provision in the rule that states if a facility does a stack test or fuel analysis using the appropriate methods and procedures set out in the rule and obtains a result that is labeled as non-detect but is above the emission limit, the source has 60 days to retest and demonstrate that emissions or fuel constituents are below the standard.

M. OTHER ISSUES OPEN FOR COMMENTS – EMISSIONS AVERAGING

[39] 76 Fed. Reg. 80611.

1. *THE EMISSIONS AVERAGING PROVISIONS SHOULD ALLOW OWNERS OR OPERATORS OF A SOLID FUEL OR LIQUID FUEL BOILER TO REPOWER (CONVERT) THAT BOILER TO NATURAL GAS (GAS 1) WITHIN THE AVERAGING PROCESS.*

On page 80617 of the Reconsidered Proposal, EPA, in response to input from stakeholders, solicits comment on a suggested approach to allow an existing unit that is converted to natural gas to be included in an emissions average with other similar existing units. EPA's request for comment is shown below:

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

ACC strongly supports allowing companies to convert coal-fired units to cleaner-burning gas fuels without revoking that unit's eligibility for emissions averaging with remaining coal-fired units. For some companies, switching boilers from coal to cleaner-burning natural gas will offer the best environmental <u>and</u> 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 CAA §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 voluntarily 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.[40]

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 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.*, MATS at 411; *Northeast Maryland Waste Disposal Authority v. EPA*, 358 F.3d 936,

[40] 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 Boiler 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.

(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:[41]

> *§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 lacks authority to allow averaging across subcategories or that such allowance would be inconsistent with its policy in providing emissions averaging options in other rules. However, as discussed in the preamble to the HON (Hazardous Organic NESHAP for the Synthetic Organic Chemicals Manufacturing Industry (SOCMI) (59 Fed. Reg. 19425, April 22, 1994)), the rule EPA cites as precedent for emissions averaging, EPA has itself acknowledged its wide discretion to define "source" broadly. Indeed, in the case of the HON, EPA defined the source category to include all emission points relating to SOCMI production at a facility – a range of emission points and technologies far more diverse than the differences between coal-fired and converted coal-to- gas boilers. The HON allows all emission points that have numerical emission standards to participate in an emissions average. Process vents, storage vessels, transfer rack, and wastewater streams are all allowed in the emissions average and they all have differing emission standards. Only equipment leaks, which have no defined allowable emission level, are excluded.

To be clear, ACC 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-

[41] 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.

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 this 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, SO_2 (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.

2. *AVERAGING FOR PM ACROSS SOLID FUEL SUBCATEGORIES SHOULD BE ALLOWED.*

In response to comments received on the 2010 Proposed Boiler Rule that emissions averaging should be allowed across subcategories, EPA stated:

> *"While EPA did not make major adjustments to the emissions averaging provisions, the change to a solid fuel subcategory will enable all solid fuel-fired units at a facility to use the emissions averaging provision for Hg, PM, and HCl. Beyond this, EPA disagrees that it is appropriate to average across subcategories for affected sources with mixed streams (e.g. SOCMI) and the commenter does not provide sufficient justification for swaying from this precedent." (see Response to Comments Document (Document Control Number EPA-HQ-OAR-2002-0058-3137.1)*

In the Final Boiler Rule, EPA allowed any solid fuel units at a given facility to use averaging to comply with the Hg, PM, and HCl standards. Now, in the Reconsidered Proposal, EPA has reverted to the case where solid fuel units in different subcategories with different PM emission standards are not allowed to use emissions averaging (*see* §63.7522(b)(3)).

Such restriction on the use of emissions averaging is arbitrary and will only serve to increase the cost of the final rule. While EPA claims the commenters gave no justification for allowing averaging across subcategories, that is not the case as is reflected in the excerpt below from comments submitting by the Eastman Chemical Company, an ACC member:

> *On page 32034 of the preamble, EPA states one of its limits on the scope of emissions averaging is to not allow averaging between sources that are not part of the same affected source. In this case, EPA has elected to define the affected source in §63.7490(a)(1) as all units within a subcategory. We see no reason for EPA to use this definition. Rather all units at a given facility subject to the subpart should be collectively considered the "affected source". This is how EPA has defined the term in other rules with which we are familiar (e.g. the HON in Subpart F, Polymer and Resins 4 in Subpart JJJ, the MON in Subpart FFFF). The HON in particular we*

> *understand is the model EPA is using to guide its policy. By defining the term affected source as all chemical manufacturing process units (CMPUs) at a facility, the HON allows emissions averaging across CMPUs and across emission unit types (vents, storage vessels, transfer racks, wastewater stream). There is no reason in the boiler and process heater MACT for EPA to restrict the emissions averaging alternative as it has proposed. To do so, will prevent some facilities from taking advantage of the opportunity to avoid otherwise cost-prohibitive compliance options by over-controlling some other emission unit in a more cost-effective combination.*
>
> *Also, by not allowing averaging across the different fuel categories, EPA removes an incentive to burn more natural gas or renewable fuels such as biomass as a strategy to average out emissions from a coal-fired unit.*

EPA states in its response that allowing averaging across mixed streams (i.e. subcategories) would be swaying from its precedent. Just the opposite is true: the HON, which set the precedent for the use of emissions averaging, allows emissions averaging across different types of emissions units from different chemical manufacturing process units. It does not allow averaging across different pollutants – which we are <u>not</u> suggesting EPA allow in the Boiler MACT. The preamble to the HON Final Rule (59 Fed. Reg. 19425, April 22, 1994) provides EPA's rationale for the emissions averaging provisions. It states that the Agency has broad discretion to define "source." In the case of the HON, "source" is defined as all emission points relating to SOCMI production at a facility. It allows all emission points that have numerical emission standards to participate in an average. Process vents, storage vessels, transfer rack, and wastewater streams are all allowed in the emissions average and they all have differing emission standards. Only equipment leaks, which have no defined allowable emission level, are excluded. Accordingly, EPA has all the latitude it needs to allow emissions averaging across <u>all units</u> at a given facility that are subject to Subpart DDDDD, so long as they have an applicable numeric emission limit.

If EPA is concerned that it cannot allow emissions averaging across subcategories because the subcategories have different emission standards, this concern is easily addressed. As in the HON, the compliance methodology can easily accommodate subcategories with different emission limits for a given pollutant. This is done by calculating debits and credits and assuring that credits (after discount) are equal to or greater than debits (*see* §63.150(e)). An example is provided below to demonstrate this concept:

> A facility has one pulverized coal (PC) boiler with a rated capacity of 500 mmBtu/hr and a PM emission rate of 0.07 lb/mmBtu and one stoker boiler with a rated capacity of 250 mmBtu/hr and a PM emission rate of 0.07 lb/mmBtu. Both of these boilers exceed their respective PM emission standards of 0.044 lb/mmBtu and 0.028 lb/mmBtu. The stoker is older, smaller, and much more difficult to retrofit and use of a fabric filter poses a safety hazard (due to sparks). In order to conserve capital (which it can use for growth projects and assist with the nation's economic recovery), the facility would like to install a state-of-the art fabric filter (with a PM emission rate of 0.01 lb/mmBtu) on the PC boiler and avoid a capital investment on the stoker. If the rule were to allow averaging, the credits and debits based on rated heat input capacities would be determined as follows (likewise, each month, the credits and

debits are calculated based on actual heat inputs for that month for each unit in the average and a twelve month rolling sum of credits vs. debits is recorded):

Credits from PC Boiler = 0.9 * [500 mmBtu/hr * (0.044-0.01 lb/mmBtu)] * 720 hours/month = 11,016 lbs

Debits from Stoker Boiler = [250 mmBtu/hr * (0.07 – 0.028 lb/mmBtu)] * 720 hours/month = 7,560 lbs

We are not suggesting units that have no numerical emission standard be included in an emissions average. A numerical emission standard is required in order to calculate credits and debits as in the HON precedent. Therefore, a unit designed to burn gas 1 could not be included in an emission average unless (as we have commented elsewhere) it was in a subcategory with an applicable numerical emission limit as of the date of proposal. In that case, the unit's credits are determined by the difference in the emission profile proposed above (i.e. three times the detection limit of the applicable reference method) from the converted gas unit and the applicable emission rate limit defined for that unit as it existed on the date of proposal (multiplied times its heat input or steam load).

In summary, EPA has not adequately justified its decision to restrict averaging to subcategories and should remove this restriction, especially as it applies to coal-fired boilers. Otherwise, the intent of the provision to provide for flexibility and cost-effective solutions will be thwarted.

N. OTHER ISSUES NEEDING REVISION

1. THE DEFINITION OF NATURAL GAS CURTAILMENT

EPA has proposed to amend the definition of period of natural gas curtailment as follows:

> *Period of gas curtailment or supply interruption means a period of time during which the supply of gaseous fuel to an affected facility is halted for reasons beyond the control of the facility. The act of entering into a contractual agreement with a supplier of natural gas established for curtailment purposes does not constitute a reason that is under the control of a facility for the purposes of this definition. An increase in the cost or unit price of natural gas due to normal market fluctuations not during periods of supplier delivery restriction does not constitute a period of natural gas curtailment or supply interruption. On-site gaseous fuel system emergencies or equipment failures qualify as periods of supply interruption when the emergency or failure is beyond the control of the facility. (76 Fed. Reg. 80536)*

This definition presents a major concern for industry because the term "halted" is too restrictive and may be interpreted to interfere with existing contractual obligations.

Many manufacturing companies that use natural gas fired boilers and process heaters operate under contract supply agreements with local utilities, often at reduced cost to the company, in exchange for either the utility's ability to curtail the supply or a facility's commitment to switch fuels when regional demand by residential or other critical users (e.g., hospitals) is high. Critical regional demand is frequently a function of inclement weather when residential and medical facilities require more gas than normal, thus limiting the amount of gas available to industrial customers. However, most gas suppliers do not have automatic shutoff capability so they rely on industrial customers to reduce gas use when needed.

The current definition can be read to severely penalize facilities that contract for interruptible natural gas, which is the most common method of industrial gas curtailment. Interpreted literally, the current definition of curtailment includes only periods when the utility physically halts the entire supply of gas to a facility. As discussed, that is not even possible for most gas supply circumstances.

Given the many contractual arrangements possible, ACC requests that EPA modify the rule to clarify it does not intend to restrict the ability of natural gas consumers to obtain the most appropriate gas purchasing contract arrangement for their purposes. In addition, please clarify that EPA will allow use of backup liquid fuel firing under those situations where the supply of natural gas is restricted to affected facilities under a purchase contract arrangement to the extent that a very high cost or penalty would be involved for continued natural gas use at pre-restriction levels.

ACC suggests the following revision to the definition:

> *"Period of gas curtailment or supply interruption means a period of time during which the supply of gaseous fuel to an affected facility is halted <u>or restricted</u> for reasons beyond the control of the facility <u>or due to the terms of a contractual agreement with a supplier of natural gas that allows gas curtailment or supply interruption</u>. An increase in the cost or unit price of natural gas due to normal market fluctuations <u>that does</u> not <u>occur</u> during periods of supplier delivery restriction does not constitute a period of natural gas curtailment or supply interruption. <u>Restriction of supply by a natural gas supplier under a contractual order (e.g., operational flow order under a user's interruptible supply contract) does constitute a period of natural gas curtailment.</u> On-site gaseous fuel system emergencies or equipment failures also qualify as periods of supply interruption when the emergency or failure is beyond the control of the facility."*

The definition needs to be consistent between the area source and major source rules.

In addition, the requirement to notify EPA within 48 hours when oil is burned in a gas-fired unit due to curtailment is burdensome and unnecessary. Section 63.7545 requires facilities to submit a notice of natural gas curtailment of supply interruption when an alternate fuel is burned within 48 hours of the curtailment declaration. This notification requirement is an unnecessary burden on facilities, and it has the potential to result in numerous reporting violations. It should be sufficient for facilities to keep records of such events, make them available upon request, and summarize any such periods in the semi-annual compliance reports required by the rule.

2. *FUEL TO WASTE SWITCHING PROVISIONS*

ACC has long advocated the need for combustion units that intermittently burn solid waste to be able to move between §129 and §112 as applicable, and included comments on this issue in our submissions on both the proposed CISWI rule and the 2010 Proposed Boiler Rule . ACC does not support the fuel switching requirements that EPA promulgated in the final CISWI rule and believes EPA exceeded its statutory authority in the approach it took. In this reconsideration, EPA requests comment "on the fuel switching provisions included in the final CISWI rule, particularly on whether the provisions should include further clarification on the timeline and regulatory requirements of a fuel switch. Additionally, we are soliciting comment on an alternative time period for switching frequency (e.g., 12 months)." 76 Fed. Reg. 80458-80460 (Dec. 23, 2011). ACC appreciates the opportunity to submit comments again on this important issue and hope that EPA will seriously consider finalizing the approach advocated below.

a. EPA Should Abandon its Proposed Fuel-Switching Requirements for Regulating Sources that Intermittently Combust a Solid Waste Because EPA Lacks Authority Under §129 to Regulate these Units as CISWI When They Are Not Burning a Solid Waste.

Some ACC members operate units that intermittingly combust a solid waste generated on-site from manufacturing operations. These units switch between burning a traditional fuel and solid waste fuel as needed. ACC appreciates EPA's attempt to address fuel-switching and acknowledge that it presents some unique regulatory issues as these units move from being regulated under §129 as CISWI to being regulated under §112 as boilers, and vice versa. *See* 76 Fed. Reg. 80458–60. However, ACC believes that the approach EPA has chosen to address such fuel switching is contrary to the plain language of §129 and unlawful.

EPA's proposed approach is that "[u]nits that cease combusting solid waste remain subject to CISWI for at least 6 months after solid waste is added to the combustion chamber. After 6 months, sources must either comply with any applicable section 112 standards or, if they intend to combust solid waste in the unit in the future, opt to remain subject to CISWI." *Id.* at 80501 (to be codified at 40 C.F.R. §60.2265). The proposed definition of CISWI unit in § 60.2265 reads in relevant part "any distinct operating unit of any commercial or industrial facility that combusts, *or has combusted in the preceding 6 months*, any solid waste." (Emphasis added).

The requirement that sources remain subject to CISWI for 6 months after their last combustion of solid waste is unlawful. Section 129(g)(1) defines solid waste incineration unit, in relevant part, as "a distinct operating unit of any facility which *combusts* any solid waste material." (Emphasis added). Congress did not say "which combusts, *or has combusted in the preceding 6 months*, any solid waste," or more generally, "which *recently combusted* any solid waste material." Instead, Congress chose the present tense "combust" to express its clear intent to regulate only units currently combusting solid waste. EPA must "give effect to the unambiguously expressed intent of Congress" under step 1 of the *Chevron* test. *See Chevron USA v. NRDC*, 467 U.S. 837, 842-43 (1984). Since Congress was clear in its intent to only regulate solid waste incineration units *currently* combusting waste, EPA's expansion of the definition of CISWI to regulate units that *have* burned waste in the past but have stopped is illegal.

Similar reasoning applies to EPA's proposal in §60.2145(a)(4) that a CISWI unit give EPA 30-days' notice prior to the effective date of a fuel switch from a waste to a non-waste fuel. This prior notice requirement also continues to illegally regulate the unit under § 129 after it has ceased burning waste. For example, a unit that stops combusting waste on January 1st and notifies EPA of its waste-to-fuel switch on that same date would continue to be regulated as a CISWI until January 31st. As stated above, this is an impermissible expansion of §129 requirements to a unit not combusting waste material. *See Chevron*, 467 U.S. at 842-43.

b. EPA's 6-month Requirement Could Illegally Subject Units that No Longer Burn Solid Waste to § 112 and 129 Standards Simultaneously.

Under §129(h)(2), Congress limited EPA's authority to regulate CISWI units by stating that "no solid waste incineration unit subject to performance standards under [CISWI – sections 111 and 129] shall be subject to standards under [NESHAP – section 112]." The recent ruling from the D.C. Circuit Court of Appeals highlighted the mutual exclusivity of §112 and §129. In *Portland Cement Ass'n v. EPA*, 2011 U.S. App. LEXIS 24577, at *12 n.2 (D.C. Cir. Dec. 9, 2011) the court notes that some cement kilns would be regulated under NESHAP and other cement kilns combusting solid waste "...would be subject to standards under the CISWI rules rather than under the NESHAP rules, since the two regimes are mutually exclusive. *See also, NRDC v. EPA*, 489 F.3d 1250, 1256 (D.C. Cir. 2007). The reconsidered CISWI proposal would subject some units that should be subject to regulation under §112 (e.g., boilers), when and because they are combusting traditional fuels, to both §129 *and* §112 emission limits because of their intermittent combustion of solid waste.

For example, the Boiler MACT rule applies to an ICI boiler or process heater, as defined in 40 C.F.R. §63.7575, that is a major source of hazardous air pollutants. 40 C.F.R. §63.7485. The Boiler MACT states in §63.7575 that a unit "combusting solid waste . . . is *not* a boiler." In other words, as soon as a major source unit subject to §129 regulation stops burning solid waste, it would be a combustion unit regulated by the Boiler MACT §112 standards. But under EPA's fuel-switching approach, the unit would continue to be a "solid waste incinerator," subject to §129 standards for at least 6 months after the unit stops burning waste. This 6-month overlap between the start of Boiler MACT applicability and the end of CISWI applicability is impermissible because it would subject a unit to both §129 and §112 standards in violation of those sections of the CAA and D.C. Circuit case law.

Fortunately, there is precedent for a fuel switching provision that is both lawful and workable, and would assure that a combustion unit is subject to either the CISWI or the Boiler MACT rule requirements at all times, but not to both simultaneously. The fuel switching provisions in the 2005 NESHAP for Hazardous Waste Combustors ("HWC MACT") have been in place for many years and are operating successfully. *See* 40 C.F.R. §§63.1200 et seq., 63.1206(b)(ii) & 63.1209(q). The HWC MACT allows units that intermittently combust hazardous waste to comply with either Subpart EEE, some other subpart promulgated under §112 or §129, depending on whether the unit is combusting hazardous waste. 40 C.F.R. §63.1206(b)(ii).[42] In

[42] When hazardous waste is not in the combustion chamber (i.e., the hazardous waste feed to the combustor has been cut off for a period of time not less than the hazardous waste residence time) and you have documented in the operating record that you are complying with all otherwise applicable requirements and standards promulgated under authority of sections 112 (e.g., 40 CFR part 63, subparts LLL, DDDDD, and NNNNN) or 129 of the Clean Air Act in lieu of the emission standards under §§ 63.1203, 63.1204, 63.1205, 63.1215, 63.1216, 63.1217, 63.1218, 63.1219, 63.1220, and 63.1221; the monitoring and compliance standards of this section and §§ 63.1207 through

relevant part, the emission standards and operating requirements set forth in the HWC MACT do *not* apply "when hazardous waste is not in the combustion chamber" and the unit's compliance with other §§112 or 129 requirements has been documented. *Id.*

The HWC MACT requires that if the unit is going operate under different modes of operation, the owner/operator must establish operating parameter limits for each mode. Additionally, the owner/operator must document in the operating record when the unit changes a mode of operation and begins complying with the operating limits for an alternative mode of operation. In order to operate under otherwise applicable requirements promulgated under §§112 or 129, the owner/operator must specify the otherwise applicable requirements as a mode of operation in its Documentation of Compliance; its Notification of Compliance; and its Title V permit application. These requirements include the otherwise applicable requirements governing emission standards, monitoring and compliance, notification, reporting and recordkeeping. *See §*63.1209(q)(1).

ACC recognizes that hazardous waste combustion units, unlike solid waste combustion units, are exempted from the definition of "solid waste incineration unit" in §129(g) so EPA is not *required* to regulate these units under § 129. Nonetheless, if EPA can offer regulatory flexibility for units that intermittently combust *hazardous* waste, it should certainly do the same for units that intermittently combust non-hazardous solid waste.

The regulatory approach taken in the HWC MACT could easily be adapted and applied permissibly under §129. This would ensure that when combusting a solid waste the unit is regulated under §129, and when combusting a traditional fuel it is regulated under §112. One of these strict regulatory regimes would be applicable at all times, there would be no regulatory gaps and no confusion as to which set of requirements apply and the burden would be on the owner/operator to ensure that it is in compliance with one of these regulatory regimes at all times.

3. Quarterly Reporting of all Parameter Monitoring Data

EPA has included a new requirement in the Reconsideration Proposal that will be excessively burdensome to industry. This requirement is not discussed in the preamble and is not justified.

New section 63.7550(j) states:

> *Within 60 days after the reporting periods ending on March 31, June 30, September 30, and December 31, you must transmit quarterly reports to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (www.epa.gov/cdx). For each reporting period, the quarterly reports must include all of the calculated 30 day rolling average*

63.1209, except the modes of operation requirements of § 63.1209(q); and the notification, reporting, and recordkeeping requirements of §§ 63.1210 through 63.1212.

> *values based on the daily CEMS (CO and Hg) and CPMS (PM CPMS output, scrubber pH, scrubber liquid flow rate, scrubber pressure drop) data.*

EPA has not yet built this interface, so industry has had no opportunity to provide comment on its usability or the burden it will impose. This addition to the rule was incorrectly characterized as a technical correction in Table 3 of the preamble.
More importantly, the regulated community has had no opportunity to evaluate the compatibility of existing data acquisition systems with this new EPA system. There is no reason for EPA to require the submittal of all of a facility's monitoring data. EPA has provided no justification for this new requirement. Facilities will provide certifications on their semi-annual compliance reports that they have performed the required monitoring and will provide information on any deviations from monitoring requirements or established parameter ranges.

Additional parametric monitoring reports provide no useful purpose, environmental or otherwise, to anyone and are an additional administrative burden on operating facilities. EPA has already increased reporting burden by requiring all test data to be submitted electronically through the ERT, which continues to be revised and updated due to various flaws. ACC expects that this CEDRI interface would suffer from the same issues and may not even be available when facilities must submit their first of these quarterly reports. It is unreasonable to put sources at risk of violations (late reporting) because of EPA reporting tool issues or availability. In order to simplify the rule requirements, EPA should not require submittal of these additional data at this time, and instead should keep this as a recordkeeping requirement against which any deviations will be reported under a site's Title V Operating Permit.

4. THE HOT WATER HEATER DEFINITION SHOULD BE REVISED

ACC agrees that hot water heaters should be exempted from this rule as indicated in § 63.7491. However, EPA proposes to define hot water heater as follows:

> *Hot water heater means a closed vessel with a capacity of no more than 120 U.S. gallons in which water is heated by combustion of gaseous or liquid fuel and is withdrawn for use external to the vessel at pressures not exceeding 160 psig, including the apparatus by which the heat is generated and all controls and devices necessary to prevent water temperatures from exceeding 210 degrees Fahrenheit (99 degrees Celsius). Hot water boilers (i.e., not generating steam) combusting gaseous or liquid fuel with a heat input capacity of less than 1.6 million Btu per hour are included in this definition. Hot water heater also means a tankless unit that provides on demand hot water.*

ACC concurs that there should be some objective standard to distinguish hot water heaters from steam generators. An easily verifiable, and rational method, for distinction is on a mechanical design basis. The ASME Code, Section IV- Rules for Construction of Heating Boilers, is applicable to hot water heating boilers and is, in our opinion, the standard that should be used to define a hot water heater consistent with industry standards. The ASME Code, Section IV is applicable to: "(a) steam boilers for operation at pressures not exceeding 15 psi; (b) hot water heating boilers and hot water supply boilers for operating at pressures not exceeding 160 psi and/or temperatures not exceeding 250°F, at or near the boiler outlet."

ACC does support the inclusion of the heat input capacity limitation and inclusion of tankless water heaters in the definition, and recommends that EPA revise the definition of hot water heater to read as follows:

> *Hot water heater means a closed vessel in which water is heated by combustion of gaseous or liquid fuel and is withdrawn for use external to the vessel at pressures not exceeding 160 pounds per square inch gauge (psig), including the apparatus by which the heat is generated and all controls and devices necessary to prevent water temperatures from exceeding 250°F (121°C) at or near the heater outlet. Hot water boilers (i.e., not generating steam) combusting gaseous or liquid fuel with a heat input capacity of less than 1.6 million Btu per hour are included in this definition. Hot water heater also means a tankless unit that provides on demand hot water.*

Alternatively, if EPA feels size thresholds are warranted, ACC suggests reorganizing the proposed definition for clarity. EPA should reword the definition of hot water heater to make it clear that a hot water heater is "a closed vessel with a capacity of no more than 120 U.S. gallons or with heat input no more than 1.6 million Btu/hr and is withdrawn for use external to the vessel at pressures not exceeding 160 psig, including the apparatus by which the heat is generated and all controls and devices necessary to prevent water temperatures from exceeding 210 degrees Fahrenheit (99 degrees Celsius). Hot water heater also means a tankless unit that provides on demand hot water."

5. *THE DEFINITION OF UNIT DESIGNED TO BURN GAS 1 SUBCATEGORY SHOULD BE REVISED*

In the Reconsideration Proposal at § 63.7575, EPA defines units designed to burn Gas 1 as:

> *"any boiler or process heater that burns only natural gas, refinery gas, and/or other gas 1 fuels; with the exception of liquid fuels burned for periodic testing not to exceed a combined total of 48 hours during any calendar year, or during periods of gas curtailment and gas supply emergencies."*

EPA then defines oil (liquid) unit as:

> *"any boiler or process heater that burns any liquid fuel, but less than 10 percent coal/solid fossil fuel and less than 10 percent biomass/bio-based solid fuel on an annual heat input basis, either alone or in combination with gaseous fuels. Gaseous fuel boilers and process heaters that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year or during periods of maintenance, operator training, or testing of liquid fuel, not to exceed a combined total of 48 hours during any calendar year are not included in this definition. Gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply emergencies of any duration are also not included in this definition."*

In the proposed reconsidered area source rule at 40 CFR 63.11237, EPA defines a gas-fired boiler as "any boiler that burns gaseous fuels not combined with any solid fuels, <u>burns liquid fuel only during periods of gas curtailment, gas supply interruption, startups, or periodic testing on liquid fuel</u>. Periodic testing of liquid fuel shall not exceed a combined total of 48 hours during any calendar year." (emphasis added) (76 Fed. Reg. 80547, December 23, 2011)

EPA has consistently used 10% as a threshold for movement from one subcategory to another. For example the most stringent – coal – includes units that burn at least 10% coal. The next – biomass – includes units that burn at least 10% biomass and less than 10% coal. The first sentence of the oil (liquid) subcategory includes any liquid fuel, but less than 10 % solid fuel. Therefore, it logically follows that a plain reading of the Gas 1 subcategory would be that EPA intended to include any unit that burns at least 90% gas and less than 10% of any other fuel. EPA should include an allowance for oil firing in the Gas 1 subcategory definition of 10 percent (as allowed in other subcategory definitions). At a minimum, EPA should make the Gas 1 subcategory definition consistent with the area source definition, which places no restriction on oil firing during startup. A new gas-fired boiler that is designed to burn liquid fuel as backup must be allowed to burn oil for more than 48 hours per year in order to ensure that the oil burners are properly tuned during initial startup.

ACC proposes the following definition for the Gas 1 subcategory:

> *"Unit designed to burn gas 1 subcategory includes any boiler or process heater that burns at least 90 percent natural gas, refinery gas, and/or other gas 1 fuels on a heat input basis on an annual average and less than 10 percent of any solid or liquid fuel."*

This definition change would simplify the process of determining if a unit qualifies for the gas 1 subcategory and would eliminate the need to determine whether periods during which liquid fuel is fired constitute natural gas curtailment, gas supply emergency, or periodic testing. It would also accommodate the need to be able to burn oil during initial startup in order to test and tune the oil burners on a new unit or an existing unit where new burners have been installed. EPA already acknowledges in §63.7510(a)(2)(i) that units burning a supplemental fuel for startup, shutdown, and transient flame stability purposes are single fuel units, and the supplemental fuel is not subject to fuel analysis requirements.

This change would also be consistent with how EPA has defined the Gas 2 subcategory (the definition includes an allowance for burning 10 percent liquid fuel):

> *"Unit designed to burn gas 2 (other) subcategory includes any boiler or process heater that is not in the unit designed to burn gas 1 subcategory and burns any gaseous fuels either alone or in combination with less than 10 percent coal/solid fossil fuel, less than 10 percent biomass/bio-based solid fuel, and less than 10 percent liquid fuels on an annual heat input basis."*

6. EPA Should Clarify the Definition of Liquid Fuel

The definition of "liquid fuel" at § 63.7575 currently includes the words "on-spec used oil," but "on-spec used oil" is not defined in the Final Boiler Rule. Congress recognized that in establishing air standards to meet requirements in the CAA and RCRA, there may be regulatory overlaps between the two statutes. Congress therefore intended for EPA to minimize, if not eliminate regulatory overlap to the maximum extent practicable and to harmonize requirements so that they are consistent. See, for example, § 112(n)(7) of the CAA and § 1006(b) of RCRA. Based on these Congressional directives, ACC believes that EPA should delete the term "on-spec used oil," as the Boiler MACT rule fails to define "on-spec," and instead use the term "used oil" which is a defined term in RCRA at 40 CFR 279.11.

III. TECHNICAL CORRECTIONS AND CLARIFICATIONS

The following are several technical or reference errors noted in the proposed rule that require correction:

- To avoid confusion, EPA should make sure that the final preamble language addresses and matches the final requirements in the rule. For example, in this Reconsideration Proposal, the preamble indicates that a new fuel analysis is required for each new fuel supplier (*see* 76 Fed. Reg. 80604). This requirement is unreasonable and is not included in the regulatory text. The preamble also indicates that ESP parameter monitoring is based on a 12-hour block average (*see* 76 Fed. Reg. 80603), which conflicts with Table 4 of the rule.

- Section 63.7522(d) states, "The averaged emissions rate from the existing boilers and process heaters participating in the emissions averaging option must be in compliance with the limits in Table 2 to this subpart at all times following the compliance date specified in § 63.7495." Please clarify that compliance must be met "at all times <u>that the unit is subject to numeric emission limits"</u> (emphasis added) as numeric emission standards do not apply during periods of startup and shutdown.

- The same change is needed for § 63.7533 (e) with respect to compliance with the output based limits.

- The same change is needed for § 63.7540(a)(8)(ii), which specifies that if you are using a CO CEMS you must maintain a CO emissions level below or at your Table 1 or 2 limit <u>at all times</u> (emphasis added).

- Table 1, Item 5.a. specifies that a span value of 600 ppmv is to be used for Method 10. This appears to be an error since the CO limit for that subcategory is 590 ppmv. For comparison, other Table 1 and 2 CO M10 span requirements are in the range of 2 times the emission limit. Therefore, it is recommended to change the required span for Table 1, Item 5.a to be 1000 ppm.