BEFORE THE ADMINISTRATOR
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

In the Matter of the Final Rule: National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters	))))))))	RIN 2060-AQ25 EPA Docket No. OAR-2002-0058

PETITION FOR RECONSIDERATION

Pursuant to Section 307(d)(7)(B) of the Clean Air Act, 42 U.S.C. § 7607(d)(7)(B), the American Chemistry Council ("ACC") hereby petitions the Administrator of the United States Environmental Protection Agency ("EPA") to reconsider portions of the final rule National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters ("Final Rule" or "Boiler MACT"), published in the Federal Register at 76 Fed. Reg. 15,608 (Mar. 21, 2011). As set forth in detail below, ACC respectfully requests that EPA:

- **Reconsider the numerical standards for dioxin/furans, and instead propose for comment a work practice standard, as was done in the recently proposed utility MACT rule**

- **Even if EPA chooses not to propose work practice standards for dioxin/furans, it must reconsider those numerical standards because it failed to adjust the limits for detection level variability**

- **Reconsider and propose standards for Hg, HCl, and PM for coal fired units and biomass fired units as separate subcategories rather than as a combined solid fuel subcategory**

- **Reconsider and (a) propose standards for limited use units based on a capacity factor rather than hours per year, (b) modify the new tune-up provisions for process heaters that operate on a very limited basis, and (c) treat predominantly Gas 1 fired units the same as limited use units**

- **Clarify the definition of "period of natural gas curtailment or supply interruption" to acknowledge that periods of natural gas curtailment under a contract are beyond the control of the facility, and that all types of contractual arrangements as well as on site natural gas emergencies are allowed**

- **Reconsider and propose an emission testing frequency to be consistent with the five year Title V permit review cycle; allow a CEMS option in lieu of an annual stack test or fuel monitoring for Hg, PM, and HCl; and reconsider its decision to disallow minimum CEMS data availability provisions**

- **Reconsider the Gas 1 subcategory and include petrochemical gases; and, reconsider the opt-in provisions to allow Gas 2 units whose process gases contain H_2S concentrations similar to those in refinery fuel gas to opt-in to Gas 1 work practice requirements**

- **Reconsider and limit the scope of the energy assessment requirement to the equipment associated with the on-site regulated combustion source, and delete the maximum time requirements for the assessment**

- **Reconsider and revise the O_2 monitoring requirements for CO; allow for an alternative CO limit based on use of a CO CEMS; however, if an alternative CO limit is not allowed, then clarify that CO CEMS data gathered to meet state regulatory requirements shall not be considered in determining compliance with CO limits established in the Final Rule**

- **Revise the startup/shutdown provisions to clarify their applicability**

- **Reconsider the affirmative defense provisions for malfunctions to provide notice and an opportunity to comment on the provisions**

In addition, at the end of this petition ACC has included a number of issues that it believes require technical correction and/or clarification.

I. THE PETITIONERS

ACC is a not-for-profit trade association that participates on its members' behalf in administrative proceedings and in litigation arising from those proceedings. ACC represents the leading companies engaged in the business of chemistry. These companies rely in part on the use of industrial boilers and process heaters that are subject to the Final Rule.

II. GROUNDS FOR RECONSIDERATION

Pursuant to section 307(d)(7)(B) of the Clean Air Act (CAA), if a petitioner shows "that it was impracticable to raise [its] objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment . . . and if such objection is of central relevance to the outcome of the rule, the Administrator shall convene a proceeding for reconsideration of the rule." 42 U.S.C. § 7607(d)(7)(B). As detailed below, each of the specific provisions for which ACC seeks reconsideration meets these requirements.

III. SPECIFIC PROVISIONS FOR WHICH RECONSIDERATION IS SOUGHT

1. EPA should reconsider the numerical standards for dioxin/furans, and instead propose for comment a work practice standard, as was done in the recently proposed utility MACT rule.

In the Final Rule, EPA established numerical emission limits for dioxins/furans (D/F) from major coal fired industrial, commercial, institutional (ICI) boilers.[1] Final Rule, 76 Fed. Reg. at 15612, Table 1. By contrast, EPA established work practice standards for these same pollutants in its recently proposed electric utility MACT rule. *See,* Proposed Rule, 76 Fed. Reg. 24976, 25027 (May 3, 2011) (hereinafter "Utility MACT"). As set forth below, ACC believes that EPA should reconsider its decision to promulgate numerical emission standards for D/F from ICI boilers and propose work practice standards instead for the following reasons: (1) EPA's purported distinctions between utility boilers and ICI boilers regarding D/Fs are arbitrary and capricious; (2) the uncertainty of D/F data is such that work practice standards are appropriate, if not compelled; (3) EPA's assumption of no incremental cost for ICI boilers to meet the D/F standards is incorrect and not supported by the record; and (4) ICI coal fired boilers have an adequate presence of sulfur to inhibit D/F formation in the same manner as utility boilers.

A. EPA's distinctions between utility boilers and ICI boilers do not hold up under scrutiny -- there is no compelling reason to require emission limits for ICI boilers, but work practice standards for utility boilers.

EPA distinguishes utility boilers from ICI boilers on the alleged grounds that ICI boiler D/F levels were higher, on average, for ICI boilers than for similar utility boilers, this difference supposedly being "significant from a testing feasibility perspective." Utility MACT, *id.* at 25040. In the preamble to the proposed utility MACT rule, EPA states:

> 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 limit, we are proposing a work practice standard under CAA section 112(h). We do not believe that this approach is inconsistent with that taken on other NESHAP where we also had issues with data at or below the MDL (e.g., Portland Cement NESHAP; Boiler NESHAP). In the case of the Boiler NESHAP, the MDL issue was with the

[1] We note that EPA is initiating reconsideration of this issue. National Emission Standards for Hazardous Air Pollutants; Notice of Reconsideration, 76 Fed. Reg. 15266, 15267 (Mar. 21, 2011) (to be codified at 40 C.F.R. Parts 60 & 63) (hereinafter Notice of Reconsideration).

> organic HAP. For that rulemaking, the required sampling time during conducting of the associated ICR was 4 hours, as opposed to the 8 hours required in the 2010 ICR. Further, a review of the data indicates that the dioxin/furan HAP levels (a component of the organic HAP) were at least 7 times greater, on average, for coal-fired IB units and 3 times greater, on average, for oil-fired IB units than from similar EGUs. We think this difference is significant from a testing feasibility perspective.

Id. There are numerous problems with EPA's statement that go to the heart of why the Agency's distinction between utility boilers and ICI boilers is arbitrary and capricious. First, EPA is "splitting hairs" at best to say that D/F emissions from ICI boilers are significantly different from utility boilers from a testing feasibility perspective. Using the data EPA has made available for both rules ACC compared average and total emission rates of D/Fs from the two sectors. That comparison is shown below.

ICI Coal Boilers	Pulverized Coal	Stoker	Fluidized Bed	Total/Average
Average D/F (ng/dscm)	0.0104	0.005	0.0092	0.00704
Average D/F (lb/MMBtu)	6.35E-12	3.05E-12	5.62E-12	4.30E-12
Number of Boilers	186	339	30	555
Average Size (MMBtu/hr)	373	184	549	267
Average Op Hours per Year	7,325	6,315	7,903	6,739
Total MMBtu/yr	533,592,973	424,042,292	134,116,350	1,091,751,614
Total D/F (g/yr)	1.5	0.6	0.3	2.5
Average D/F (g/yr)	0.0083	0.0017	0.0114	0.0044

EGU Coal Boilers				
Average D/F (lb/MMBtu)	1.89E-13			
Number of Boilers	1,061			
Average Size (MMBtu/hr)	3,003			
Average Op Hours per Year	6,130			
Total MMBtu/yr	19,531,301,790			
Total D/F (g/yr)	1.7			
Average D/F (g/yr)	0.0016			

This table shows that total D/F emissions estimated for the two sectors only differs by about 32% (2.5 grams for ICI boilers vs. 1.7 grams for utility boilers). The average D/F emissions for ICI coal boilers is only 2.8 times higher than for utility boilers – not seven times higher as concluded by EPA.[2]

Second, both EPA and ACC's comparisons are imprecise due to the different test run times upon which the comparisons are based. As EPA noted above, the ICI boiler data set was determined using 4 hour test runs rather than eight-hour test runs as EPA prescribed for the utility ICR testing. Accordingly, the ICI data is biased high due to the fact that the method detection limits are higher (due to shorter run times collecting less gas sample). Any congener reported as "non-detect" (ND) for ICI boilers will be entered into EPA's databases with higher concentrations relative to the utility boiler dataset. Given that the Toxic Equivalency Factor ("TEF") methodology weights some congeners as much as 1,000 times others, a high detection limit for one of the highly weighted congeners (such as 2,3,7,8 TCDD) for the ICI data set relative to the EGU dataset will skew the estimated emissions considerably. Based on the available data, we conclude that EPA's statement that ICI boilers' D/F emissions are

[2] We have searched the dockets for these rules, but we have not been able to find any documentation for EPA's "7 times" claim.

significantly greater than utility boilers, and therefore warrant numerical emission standards, is not supported by the facts.

Third, EPA observes that a significant majority of the utility test runs were at or below MDL even with eight-hour test runs. This observation is not relevant to EPA's decision to establish D/F numerical emission limits for ICI boilers because EPA did not require eight-hour test runs for the ICI boiler testing. The Agency does not know what percentage of ICI boiler test runs also would be below the MDL if ICI boilers had been required to undertake eight-hour test runs.

Finally, EPA's statement in the utility MACT that "[o]verall, the available test methods are technically challenged, to the point of providing results that are questionable for all of the organic HAP" is equally applicable to ICI boilers. The D/F performance testing required by the final rule specifies four-hour test runs and will normally require two days of testing and offer significant challenges in terms of cost and feasibility. The fact that much of the reported data is "flagged" with high uncertainty (as discussed immediately below) is further evidence that the results of D/F testing for ICI coal boilers are questionable. Given that many of the reported values for the various congeners are flagged, this could compel some ICI boiler owners to believe they must attempt 8 hour test runs in order to improve the accuracy and lower the end result. If driven to this extreme, the testing is clearly impracticable and unreasonable.

In sum, EPA appropriately proposed work practice standards for D/Fs for utility boilers. The Agency's attempt to distinguish ICI boilers is inadequate and not supported by the record. EPA should reconsider the establishment of D/F numerical emission standards for ICI boilers and instead propose work practice standards similar to its proposal in the utility MACT.

B. The uncertainty of the D/F data compel a work practice standard for ICI boilers just as it did for utility boilers.

As shown below, much of the D/F data for ICI boilers is highly uncertain. Faced with similar uncertainty, EPA set work practice standards for utility boilers. EPA should also do so here. In the utility MACT, EPA discussed the importance of the uncertainty of the data for its determination to promulgate work practice standards:

> 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. Overall, 1,552 out of 2,334, total test runs for dioxin/furan organic HAP contained data below the detection level for one or more congeners, or 67 percent of the entire data set. In several cases, all of the data for a given run were below the detection level; in few cases were the data for a given run all above the detection level. 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.

Id. at 25040.

The levels of D/F reported by ICI boilers are similarly very low. Of the 333 test runs included in EPA's emissions test database, 77.17% are below detection levels for one or more congeners.[3]

A deeper review of the D/F data submitted by ACC members in response to EPA's Phase II ICR reveals even further uncertainty than meets the eye. D/F sampling and analytical methods offer unique challenges. For example, one ACC member company submitted data for a boiler in which every congener in each test run was either reported as ND or reported a value that was flagged with a "J" qualifier. The "J" qualifier indicates that the analyte was quantified with a concentration below the reporting limit, defined as below the lowest point on the calibration curve. An excerpt from this test report is attached and the full test report was submitted by the company to EPA in 2009. Some of the congeners were also labeled "EMPC" (estimated maximum possible concentration) indicating that a peak was detected but did not meet all of the method criteria. This test report also reveals that some D/F congeners were detected in the field blank (a sample of ambient air from the sampling location), indicating background levels of D/F which cast further doubt and uncertainty to the reported analyte concentrations.

All of these "flags" indicate that there is a high degree of uncertainty associated with D/F data at the low levels found in ICI coal fired boiler stack gas. For this reason, EPA should set a work practice standard for D/F from these boilers as it did for utility boilers.

C. EPA's assumption that there will be no incremental costs for ICI boilers to comply with the D/F standards is unfounded and has no support in the record.

EPA assumes that the D/F emission limitations are reasonable because they can be met by either existing good combustion practices or as a co-benefit of controls installed to reduce mercury emissions. As we demonstrate below, each of these assumptions is unfounded and without support in the record.

In the Response to Comments document, EPA made the following statement in its response to a comment requesting the D/Fs be made eligible for emissions averaging:

> Further, both CO and dioxin/furan emissions are formed through combustion and . . . it is important for the Agency to promote good combustion on all units. Most of the limits are expected to be achieved with good combustion and combustion controls instead of add-on pollution controls and so the concerns with costs of compliance are less than those associated with PM, HCl, and Hg which often require add-on controls to be installed on individual units.

Response to Comments, EPA-HQ-OAR-2002-0058-2801.1, excerpt number 36.

[3] 4.50% (15) are below detection level (BDL) (i.e., all congeners below the method's reported detection limit), 72.67% (242) are classified as detection level limited (DLL) (i.e., at least one but not all congeners are less than the reported detection level), 21.92% (73) are above detection level (ADL) (i.e., all congeners reported above detection levels).

ACC has found no data in the docket to support EPA's statement that good combustion and combustion controls would lower D/F formation from ICI boilers. EPA's statement is merely conjecture. Much work and costly testing would have to be done to establish that combustion controls would, in fact, reduce D/F emissions to the Final Rule's standards. If a source were to pursue this approach only to find there is no reliable combustion control strategy to comply with the standard, then the source would be left without enough time to subsequently research, test, design, and install a post-combustion control strategy to meet the standard by the compliance date (even with a one year extension).

Moreover, EPA has not considered that combustion controls, e.g., hotter flame zones, will often run counter to previous efforts by sources to install low NOx combustion control systems (e.g., low NOx burners, over-fire air) as part of state and federal ozone control programs. Such sources would then have to install a post-combustion control such as selective non-catalytic reduction (SNCR) to compensate for reversals of previous NOx reductions. So, for EPA to state that D/F reductions utilizing unproven combustion control strategies will (a) be successful, or (b) come at little or no cost is simply conjecture, unsupported by anything in the record.

EPA also claims, in language inconsistent with that quoted above, that activated carbon controls used to reduce mercury will have the co-benefit of reducing D/Fs, therefore EPA estimates no control costs for achieving the D/F limits:

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

"Memorandum re. Revised Method for Estimating Cost and Emissions Impacts for Industrial, Commercial, Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants – Major Source" 5 (Feb. 17, 2011) (hereinafter "Cost and Emission Impacts Memo").

Again, there are numerous problems with these Agency assumptions. First, the assumption that ICI boilers will meet the D/F emission limitations with activated carbon injection (ACI) is inconsistent with the assumption above that the boilers will meet the standards with good combustion controls. Second, just as with the combustion controls assumption, EPA has no data to support the assumption that activated carbon systems will reduce D/Fs. This again is mere conjecture. While ACI has been used on some municipal waste and hazardous waste incinerators to reduce D/Fs, those sources are entirely different units than a fossil or biomass fuel boiler. The levels of D/Fs found in these incinerators are many times higher than the levels for ICI boilers in EPA's dataset. ACC is not aware of research or field studies that have been done to demonstrate the effectiveness (if any) or annual operating cost of ACI systems on D/F concentrations so low and close to detection levels as those found in boilers and process heaters.

To put this in perspective, there are an estimated 31 grams per year of D/Fs (TEQ adjusted) emitted from the entire major source boiler and process heater solid and liquid subcategories. *See*, Cost and Emission Impacts Memo at Appendix B-1. For the coal fired subcategory, this equates to an average annual D/F emission rate of 0.04 grams per boiler. Mercury emissions, on the other hand, are estimated at 4.3 million grams – 138,000 times higher than the D/F emissions. ACI depends on good mixing and contact between the carbon particles and the target pollutant. ACC is not aware of technology testing that would prove how effective ACI would be in contacting and adsorbing the extremely small concentrations of D/Fs in boilers and process heaters.

Additionally, it is not clear how many ICI boilers will even utilize ACI to control mercury. For example, work done by one ACC member company (in preparation for compliance with the vacated 2004 Boiler MACT), showed that ACI is not effective in controlling mercury from coal fired stoker boilers. EPA stated in the Utility MACT preamble that ACI is not very effective on boilers burning high sulfur coals. Utility MACT at 25014. Also, there is some evidence that lime or trona injection based controls used to reduce SO_2 and/or HCl may be somewhat effective at mercury control and that ACI systems may often not be required.[4] So, even if ACI were effective in controlling D/Fs, it is not a foregone conclusion that such systems will be installed absent a need to reduce D/Fs. Further confounding EPA's logic is the fact that for ACI to be effective, a downstream fabric filter is needed since the fabric filter provides additional residence time for adsorption to occur (otherwise, extremely high carbon injection rates are needed to obtain good performance of the system). Many boilers have existing ESPs rather than fabric filters. While it is true that some of these ESPs will be replaced with fabric filters to meet the particulate matter standard, many will not, or they will be upgraded to meet that standard. Sources with such configurations will likely choose dry sorbent injection (duct or furnace injection) to meet the HCl standard (if they have higher chlorine coal supplies). They will likely avoid the costly upgrades to fabric filters. Therefore, there will be fewer configurations where ACI is already incorporated than EPA has assumed.

One ACC member company, Eastman Chemical Company, has a pulverized coal boiler equipped with a spray dryer absorber and an electrostatic precipitator (ESP) (identified as Boiler 30 in EPA's database). Available test data for this boiler shows it to be capable of meeting the PM, Hg, HCl, and CO emission limits with no modification. However, the one D/F stack test shows it did not meet the D/F standard, even when substituting zeros for the congeners that were not detected. The one stack test shows the D/F emission rate at about 0.005 ng/dscm TEQ, just above the standard. The boiler is equipped with low-NOx burners and an over-fire air system for NOx control. Eastman has no data suggesting that a change in combustion conditions would

[4] "Also, many industrial boilers will be installing fabric filters to comply with the MACT PM/toxic metals standard and many will be injecting small amounts of alkaline materials to meet the HCl limit. The latter will reduce SO3 and its negative effects on native mercury capture, while the former will allow unburned carbon to reduce mercury to a high degree. See, for example, the co-benefit results from the prior utility MACT ICR, where bituminous coal boilers with fabric filters achieved an average coal mercury emission reduction of 83% even without alkaline injection for SO3 and an average reduction of 98% with alkaline spray drying. (See the EPA data from the previous ICR or Sjostrom, S., "Evaluation of Sorbent Injection for Mercury Control," DOE NETL Hg Program Review Meeting, Pittsburgh, July 12, 2005)." Response to Comments, Institute of Clean Air Companies, EPA-HQ-OAR-2002-0058-2937.1, excerpt number 17.

reduce D/Fs. Even if it had such data, it would have to install SNCR to compensate for the increased NOx emissions caused by a change in combustion operating conditions. Eastman also has no data to indicate whether ACI would reduce D/Fs at the extremely low levels that are present. Even if it had such data, Eastman would incur additional and significant capital costs and annual operating and maintenance costs if it were to install such controls to comply with the D/F standard.

In sum, the effectiveness of control strategies for D/F emissions from boilers and process heaters is unknown. Further, even if these strategies were known to work, they would add substantial costs to compliance with those emission limitations, contrary to the "no costs" asserted by EPA above.

D. ICI coal fired boilers have extremely low levels of D/Fs in their exhaust gases as a result of the presence of sulfur inhibiting D/F formation, just as utility boilers.

In the preamble to the Utility MACT, EPA explained that D/F emissions from utility boilers are low because of the absence of chlorine and the presence of sulfur.

> Dioxin/furan emissions from coal-fired EGUs are generally considered to be low, presumably because of the insufficient amounts of available chlorine. As a result of previous work conducted on municipal waste combustors (MWC), it has also been proposed that the formation of dioxins and furans in exhaust gases is inhibited by the presence of sulfur. Further, it has been suggested that if the sulfur-to chlorine ratio (S:Cl) in the flue gas is greater than 1.0, then formation of dioxins/furans is inhibited. The vast majority of the coal analyses provided through the 1999 ICR effort indicated S:Cl values greater than 1.0

Utility MACT, 76 Fed. Reg. at 25023. The same holds true for ICI boilers, and hence they should be treated in the same manner for D/Fs as utility boilers. We examined the ICR responses for the coal-fired boilers in the Boiler MACT ICR database, and found that the sulfur-to-chlorine ratio is far greater than 1:1. *See* Emissions Database for Boilers and Process Heaters Containing Stack Test, CEM, & Fuel Analysis Data Reported Under ICR Nos. 2286.01, 2286.06 (Feb. 2011). This is intuitive since sulfur content ranges from 0.5 percent to about 6 percent and chlorine is usually less than 1,000 ppm. Most any coal available for either utility or ICI boilers to burn will easily meet this 1:1 minimum ratio of sulfur to chlorine.

2. <u>Even if EPA chooses not to propose work practice standards for dioxin/furans, it must reconsider those numerical standards because it failed to adjust the limits for detection level variability</u>.

In its MACT Floor memorandum, EPA explained its procedure for accounting for measurement detection level variability in calculating the MACT floor emission limits.[5] EPA, "Memorandum re. Revised MACT Floor Analysis for Major Source Boiler MACT" 14–15 (Jan. 4, 2011) (hereinafter "MACT Floor Memo"). EPA explained that it established a "representative detection level" (RDL) for each data set and used this value to ensure the emission limit adequately accounted for measurement variability. *Id.* It did this by comparing a value of three times the RDL to the computed floor value (the 99 percent confidence UPL), and setting the

[5] We note EPA may initiate reconsideration of this issue. Notice of Reconsideration, 76 Fed. Reg. at 15267.

floor no lower than three times the RDL. *Id.* The issue here is that EPA did not follow this procedure for the D/F limitations for many ICI boilers. If it had done so, the values for those boilers would be about three times higher as described below.

ACC examined the Excel spreadsheet in EPA's Appendix D (Analysis of Representative Method Detection Level) to the MACT Floor memo. We found that EPA did not follow the procedure described above. Taking pulverized coal boilers as an example, if EPA appropriately corrected its calculations, the emission standard of 0.004 ng/dscm would be changed to 0.012 ng/dscm. In this case (and it appears EPA made these same errors in other subcategories as well), EPA made no corrections to account for measurement variability.

Further, as can be seen from tab D-2b, column F, EPA found that 3xRDL was "Not Applicable" for all of the test runs of the top performers. First, EPA compared apples and oranges by comparing the <u>sum of the average</u> TEQ adjusted RDL for the 17 isomers of D/Fs for each run to the <u>average</u> of the 17 isomers over all the test runs for all of the top performers. In other words, the RDLs were being compared to a test value that was low by a factor of 17; moreover, EPA should have been comparing 3 times the RDL, not the RDL, to the test run values. Second, EPA tested to see if the RDL for each test run was less than the average of the concentration of the 17 isomers over all the test runs for all of the top performers. What EPA should have done was multiply each value in column D (the TEQ adjusted RDL for each test run) by 3 and test to see if that value (3xRDL) was greater than the average of the sum of the 17 isomers for each of the test runs from the top performers. If EPA had done this, consistent with its stated approach, it would have found that 3xRDL was greater and would haven been used in lieu of the test run values for all six runs of the top performers to calculate the UPL. This would have effectively and appropriately tripled the emission standards.

3. <u>EPA should reconsider and propose standards for Hg, HCl, and PM for coal fired units and biomass fired units as separate subcategories rather than as a combined solid fuel subcategory</u>.

In the proposed rule, EPA set separate standards for biomass and coal-fired units.[6] National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters; Proposed Rule, 75 Fed. Reg. 32006, 32012 (June 4, 2010) (hereinafter "proposed rule"). To establish CO and D/F standards, EPA further subdivided coal into stoker, pulverized coal, and fluidized bed, and the Agency subdivided biomass into stokers, fluidized beds, suspension burners/Dutch ovens, and fuel cells. *Id.* at 32012, Table 1. The proposed rule placed certain combination-type units designed to burn both biomass and coal in the coal subcategory if they burn at least 10 percent coal on a heat input basis as an annual average. In justifying these subcategories, EPA properly recognized the differences between biomass, coal, liquid, and gas-fired units. *Id.* at 32017. Commenters advocated that combination boilers not be grouped with coal fired boilers:

> The proposed definition of any boiler burning at least 10% coal is a coal-fired boiler results in non-representative emission standards and is unfair to boilers predominantly fired with coal. EPA has arbitrarily decided to categorize

[6] We note EPA is initiating reconsideration of this issue. Notice of Reconsideration, 76 Fed. Reg. at 15267.

> combination type boilers that burn at least 10 percent coal as a coal-fired boiler. They then included emission data from such boilers along with 100 percent coal-fired boilers to establish standards for new and existing sources. This is inherently unfair to both biomass and coal fired boilers. Coal-fired boilers will inherently have higher emissions of HCl and mercury whereas biomass boilers will inherently have higher CO emissions. Eastman recommends EPA reverse its methodology and only use data from boilers burning at least 90 percent coal to set standards for the coal subcategories and to use data from boilers burning less than 10 percent coal to set standards for the biomass subcategories. For combination boilers, EPA should allow compliance to be determined using weighted averages such as in NSPS Db where EPA used this methodology for sulfur dioxide and NOx. We do not see any issues related to enforceability of such weighted average standards that cannot be overcome with today's information technology.

Response to Comments, EPA-HQ-OAR-2002-0058-3137.1, excerpt number 10.

In the Final Rule, and without any notice to the regulated community that it was going to do so, EPA grouped coal fired boilers with biomass fired boilers for fuel based pollutants (Hg, HCl and PM) into a single solid fuel subcategory. *See*, Final Rule, 76 Fed. Reg. at 15612, Table 1. This grouping is ripe for reconsideration because it appeared for the first time in the Final Rule, and hence ACC did not have an opportunity to comment upon it. We believe the grouping is unlawful because there are fundamental differences for Hg, HCl and PM emissions between coal and biomass that require separate subcategories for each fuel source. The concentrations of Hg and Cl in coal are a function of the geology and formation of the coal seams, and are factors inherent to the coal mined from different basins, and seams within basins. The concentration of Hg and Cl in biomass is a function of surface conditions (e.g. concentrations in the soil) and handling (e.g. logs floated down a brackish river can have very high concentrations of Cl). Similarly, the ash constituents in biomass tend to be high in certain alkalis that are largely absent in coal (e.g. much more MgO, Na_2O, K_2O), while significantly lower in other pollutants (SiO_2, Al_2O_3).

Because of its arbitrary grouping, the standards for coal are driven significantly lower by inclusion of biomass boilers in the subcategory of solid fuel boilers. (EPA properly excluded data from the floor that was from a unit burning less than 10 percent biomass and less than 10 percent coal.) *See*, MACT Floor Memo at Tables 1 & 2 (showing EPA's calculated MACT floor limits for the "recommended approach" and the "alternative approach"). We note that EPA has no discussion either in the MACT Floor memo or the Final Rule preamble explaining its rationale for selecting the recommended approach over the alternative approach. EPA does not even mention Table 2 in its narrative.

Coal fired boilers are fundamentally different than biomass units. For example, a coal fired boiler by design cannot burn more than 10 percent 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.

Additionally, there are fundamental differences between coal and biomass units for metals and chlorine (Cl) content. The concentration of Cd, Pb, Hg, and Cl in coal is a function of the geology and formation of the coal seams, and is a factor inherent to the coal mined from different basins, and seams within basins. The concentration of metals and Cl in biomass is a function of surface conditions (e.g., concentrations in the soil) and handling (e.g., logs floated down a brackish river can have very high concentrations of Cl). Similarly, the ash constituents in biomass tend to be high in certain alkalis that are largely absent in coal (e.g. much more MgO, Na_2O, K_2O), while significantly lower in other areas (SiO_2, Al_2O_3). There is no fundamental relationship between Hg and Cl concentrations or ash constituents between coal and biomass that would warrant their being grouped into a single solid fuel subcategory.

Lastly, by grouping coal fired units and biomass units into one subcategory, the resulting standards for Hg and HCl were based in large part on emissions from biomass units. Coal fired boilers cannot burn a higher percentage of biomass to meet the Hg and HCl standards without experiencing operational limitations, and significant physical modifications.

To resolve these issues and result in a rule that properly accounts for the different classes and types of units, EPA should set standards based on the alternative approach described in Table 2 in the MACT Floor memo. Combination boilers (those burning more than 10 percent coal) should be subject either to the limits set for coal-fired units or the recommended approach since those standards are based on a combination of biomass and coal units, while remaining subject to the limits for CO and D/F set for biomass units. This would incentivize these units that have the ability to burn more biomass to do so while not arbitrarily and unfairly causing coal-fired units to install controls to meet standards set (in part) by units from a different class and type.

4. EPA should reconsider and (a) propose standards for limited use units based on a capacity factor rather than hours per year, (b) modify the new tune-up provisions for process heaters that operate on a very limited basis, and (c) treat predominantly Gas 1 fired units the same as limited use units.

In the proposed rule, EPA did not include provisions for limited use units, and did not provide a definition of limited use units.[7] In its comments, ACC recommended inclusion of a limited use subcategory. American Chemistry Council, Comments on the Proposed Rule, EPA-HQ-OAR-2002-0058-2792 53–60 (Aug. 23, 2010) (hereinafter "ACC Comments"). While ACC discussed the limited use provisions of the Reciprocating Internal Combustion Engines (RICE) MACT, which contain limits set on an operating hour per year basis, ACC's specific recommendation was to establish a limited use subcategory on the basis of operation at no more than 10% annual capacity factor, as previously provided in the vacated 2004 Boiler MACT. *Id.* at 57. In the Final Rule, EPA appropriately created a separate subcategory for these units, and set work practice standards for them. Final Rule, 76 Fed. Reg. at 15692, Table 3. EPA defined a limited use unit as one that has a federally enforceable limit of no more than 876 hours per year of operation. *Id.* at § 63.7575. EPA justified creation of the subcategory in the preamble and in the Response to Comments document, but EPA did not respond to ACC's recommendation to define the limited use unit by its capacity factors. *See, id.* at 15633–34; Response to Comments,

[7] We note EPA is initiating reconsideration of this issue. Notice of Reconsideration, 76 Fed. Reg. at 15267.

EPA-HQ-OAR-2002-0058-2792.1, excerpt number 81. Therefore, this issue is ripe for reconsideration.

On the merits, it was appropriate for EPA to use annual hours of operation under the RICE MACT for limited use units because stationary RICE units typically operate at full engine speed and operating load is not a typically monitored variable parameter. Therefore, volumetric emissions are fairly constant when the RICE is operating.

Conversely, boilers and process heaters by design utilize variable heat input from startup conditions up to full load operation, and most units operate in a load-following mode with variable firing rate operation. Thus, actual annual emissions from boilers and process heaters are a function of operating rate as well as hours of operation. Thus, it is more appropriate to base the limited use criterion on an annual capacity factor basis which would incorporate monitoring both operating hours and fuel input or operating load.

EPA uses the annual capacity factor approach under the Acid Rain Program and NOx SIP Call. For example, there are NOx emission monitoring requirements under 40 CFR 75.12(d) that are specific to gas-fired peaking units or oil-fired peaking units. Peaking units are defined as:

> (1) A unit that has:
> (i) An average capacity factor of no more than 10.0 percent during the previous three calendar years and
> (ii) A capacity factor of no more than 20.0 percent in each of those calendar years.

40 CFR 72.2.

Capacity factor is defined as:

> (1) The ratio of a unit's actual annual electric output (expressed in MWe/hr) to the unit's nameplate capacity (or maximum observed hourly gross load (in MWe/hr) if greater than the nameplate capacity) times 8760 hours; or
> (2) The ratio of a unit's annual heat input (in million British thermal units or equivalent units of measure) to the unit's maximum rated hourly heat input rate (in million British thermal units per hour or equivalent units of measure) times 8,760 hours

Id.

EPA should revise the limited use boiler or process heater definition to read as follows, borrowing the language above from 40 CFR Parts 72 and 75:

> *Limited-use boiler or process heater* means any boiler or process heater that burns any amount of solid, liquid, or gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and has a federally enforceable **~~limit of no more than 876 hours per year of operation~~** **average capacity factor of (i) no more than 10.0 percent during the**

> **previous three calendar years and (ii) a capacity factor of no more than 20.0 percent in each of those calendar years.**

In addition, EPA should incorporate the definition of capacity factor as follows, leveraging from its use in 40 CFR Parts 72 and 75:

> *Capacity factor* means the ratio of a unit's annual heat input (in million British thermal units or equivalent units of measure) to the unit's maximum rated hourly heat input rate (in million British thermal units per hour or equivalent units of measure) times 8,760 hours.

EPA should also reconsider and modify the tune-up provisions for process heaters that operate on a very limited basis. The final rule includes a new requirement that a limited use process heater must conduct a tune-up biennially as specified in 40 CFR 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 5 or 6 times a year and at random times on an as needed and often unplanned basis. They are only and can only be used during 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 their comments that these limited use process heaters only be subject to a recordkeeping requirement. *See*, Docket ID No. EPA-HQ-OAR-2002-0058-2632 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.

Finally, EPA treated "units designed to burn gas 1" separately from limited use boilers or process heaters. But, the only material regulatory difference between units only firing Gas 1 and limited use units is that the required tune-up frequency extends from 1 year for non-limited use Gas 1 units to two years for limited use Gas 1 units. That being the case, ACC requests that EPA apply the limited use criteria to liquid firing that occurs in a predominantly Gas 1 fired boiler or process heater. Since the Gas 1/liquid limited use combination units would be operated with Gas 1 more than the limited use limitation, the tune-up frequency for those units should remain on an annual basis.

5. **EPA should clarify the definition of "period of natural gas curtailment or supply interruption" to acknowledge that periods of natural gas curtailment under a contract are beyond the control of the facility, and that all types of contractual arrangements as well as on site natural gas emergencies are allowed.**

In the proposed rule, EPA provided the following definitions:

> *Period of natural gas curtailment or supply interruption* means a period of time during which the supply of natural gas to an affected facility is halted for reasons beyond the control of the facility. An increase in the cost or unit price of natural gas does not constitute a period of natural gas curtailment or supply interruption.
>
> *Unit designed to burn oil subcategory* includes any boiler or process heater that burns any liquid fuel, but less than 10 percent solid fuel on a heat input basis on an annual average, either alone or in combination with gaseous fuels. Gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment, gas supply emergencies or for periodic testing of liquid fuel not to exceed a combined total of 48 hours during any calendar year are not included in this definition.

Proposed Rule, 75 Fed. Reg. at 32065.

ACC's comments focused on the inability to fire liquid fuels for more than the emergency period plus 48 hours, but did not address the period of natural gas curtailment or supply interruption definition. *See,* ACC Comments at 128–31. The Council of Industrial Boiler Owners (CIBO) did, however, address that definition: "CIBO requests that EPA expand the definition of gaseous fuel-fired boilers and process heaters to include gas curtailment required by a government agency (federal, state, local), natural gas supplier, or on-site gaseous fuel system emergencies." CIBO, Comments on the Proposed Rule, EPA-HQ-2002-0058-2702.1 55 (August 20, 2010). EPA did not, however, address CIBO's comments. Rather, EPA revised this provision in direct response to comments from Performance Fibers (PFI). PFI explained that many manufacturing companies that utilize natural gas fired boilers and process heaters operate under contractual supply agreements with local utilities, often at reduced cost to the company in exchange for the utility's ability to curtail the supply when regional demand is high. Surely, PFI commented, EPA did not mean to include contractual agreements with a supplier of natural gas as a reason that is "in control of the facility" because "virtually no facility that is subject to curtailment would meet the terms of this definition." Response to Comments, EPA-HQ-OAR-2002-0058-3174, excerpt number 2. PFI suggested amending the definition of period of natural gas curtailment or supply interruption as follows:

> Period of natural gas curtailment or supply interruption means a period of time during which the supply of natural gas 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 does not constitute a period of natural gas curtailment or supply interruption.

Id. The Final Rule incorporates this language verbatim. *See,* § 63.7575. While the regulatory provision is clear, an EPA statement in the preamble creates confusion:

> Likewise, the definition of "Period of natural gas curtailment" was revised to clarify that contractual agreements for curtailed gas usage or fluctuations in price do not constitute periods of gas curtailment under the scope of this regulation.

76 Fed. Reg. at 15620. This could be interpreted to mean that if a company contracts for interruptible natural gas, the use of backup liquid fuel during periods of supplier curtailment would not be allowed. We do not believe that was EPA's intention. We believe EPA intended only that the *act of entering into a contract* is under the control of the company, but it is the action of the utility to restrict gas consumption under that contractual arrangement that is beyond the control of the company, and hence constitutes a period of natural gas curtailment or supply interruption.

Other problems with the rule stem from the Agency's failure to respond in any way to CIBO's comments. First, the definition in the Final Rule arguably does not address the range of gas supply arrangements that could be entered by a company, such as purchase from a Local Distribution Company ("LDC") under state jurisdiction or an interstate gas purchase under FERC jurisdiction. Purchased transportation can be firm (a consumer contracts for a specific amount of transport capacity) or interruptible (a consumer can be interrupted by the transporting entity at the transporting entity's will). Normally, with purchase of firm transportation, the risk of curtailment is limited to an amount in excess of the firm transport capacity purchased (or the consumer's daily nomination, whichever is less). This typically occurs when demand is high, e.g., with very cold weather. Firm transport customers are normally only liable to curtailment to less then their capacity when the transporter suffers a force majeure situation, e.g., a compressor station fails, or a pipe breaks.

In the case of interstate gas, at times a consumer can buy through a curtailment, though the price is very high. In contrast, for local distribution, there is no ability to buy through and customers are required to honor the curtailment order. If they do not, the customer is subject to huge penalties for amounts taken above the contract quantity. Under interruptible service, both interstate and local distribution would be "halted" or "restricted" under Operational Flow Order (OFO) conditions (or pre-OFO conditions). While this would be on an infrequent basis, it would still be at a greater frequency than firm transport customers.

Given the myriad of complicated contractual arrangement possible in these circumstances, ACC requests that EPA clarify that the Agency does not intend to restrict the ability of natural gas consumers to obtain the most appropriate available gas purchasing contract arrangement for their purposes. And, EPA will allow use of backup liquid fuel firing under those situations where the supply of natural gas is restricted to the boiler/process heater operator under any purchase contract arrangement to the extent that either a very high cost or a penalty would be involved for continued natural gas use at pre-restriction levels.

Finally, EPA did not address CIBO's issue regarding on-site natural gas system emergencies that might occur and restrict the ability to burn natural gas in boilers and process heaters. Just as with natural gas supplier emergency conditions such as equipment or piping failures, similar failures can occur within the affected facility fence line. If and when such failures occur, it is necessary for operators to cease firing of natural gas in certain affected units. Where backup fuel is available, use of that fuel could allow facilities to remain in operation and prevent facility shutdowns or severe equipment problems due to loss of steam or process heat. EPA should allow use of backup liquid fuel under such conditions.

6. EPA should reconsider and propose an emission testing frequency to be consistent with the five year Title V permit review cycle; EPA should also allow a CEMS option in lieu of annual stack test or fuel monitoring for Hg, PM and HCl; and EPA should reconsider its decision to disallow minimum CEMS data availability provisions.

A. *A five-year testing frequency requirement is protective of the environment, cost-effective and consistent with other EPA regulations.*

The Final Rule requires a significant amount of testing. Because there are thousands of sources affected by this rule, as well as the area source boiler MACT rule and the CISWI rule, it is likely that there will be severe pressure on the limited number of stack testing personnel and laboratory facilities to do all of this testing in a timely manner. Moreover, as we discuss below, EPA has underestimated the costs of such testing, and, in any event, the benefits of testing more frequently than every five years do not justify the costs. Accordingly, ACC requests that tests be required only every five years, consistent with the Title V review cycle.

ICI boilers typically burn a number of fuels, and even when a boiler burns only coal, the nature of the contaminants in the coal varies widely depending on where it is mined and other factors. To account for this variability, and to ensure compliance with all of the emission limits in the Boiler MACT, sources will have to perform multiple stack tests, with separate tests for each pollutant, such as mercury and HCl. In the preamble to the Final Rule, EPA cites industry average costs per compliance test ranging from $60,000 to $90,000 per test. 76 Fed. Reg. at 15648. That number, however, will be much higher ($120,000 to $270,000) as sources will be required to perform two, three or even more tests to provide data on the range of fuels being combusted. Requiring such tests annually is unreasonable, and EPA has not even considered the internal costs to sources of time spent in planning, scheduling, and performing the required testing.

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

Finally, other regulations support a five year testing frequency. For example, the provisions for the Continuous Emission Monitoring for Air Programs require low mass emission units to establish NOx emission curves based on testing conducted every five years. 40 CFR 75.19(c)(1)(iv)(D). It is common practice in several states, e.g., Virginia, North Carolina, etc., to require that testing be conducted upon each five-year Title V permit renewal. All ICI boilers subject to the Final Rule are required to have Title V Permits.

B. *EPA should provide a CEMS option in lieu of annual stack tests or fuel monitoring as a compliance alternative for Hg, PM, and HCl.*

Eastman made the following comment on the proposed rule:

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

Eastman Chemical Company, Comments on the Proposed Rule, EPA-HQ-OAR-2002-0058-3137 33 (Aug. 23, 2010).

We searched the record and found no response to this comment by EPA. Eastman made similar comments in the proposed CISWI rule and we note that the final CISWI rule incorporates these alternatives. CISWI Rule, 76 Fed. Reg. 15704, 15710–11 (Mar. 21, 2011). We therefore believe that EPA may have omitted these alternatives in the Boiler MACT in its haste to promulgate the rule pursuant to the court deadline. EPA has not explained why it would include these alternatives in CISWI and not in this Final Rule. Accordingly, ACC requests that EPA reconsider Eastman's comment and propose for comment a CEMS option for companies that wish to use it.

C. *EPA should reconsider its decision to deny requests to include minimum data availability provisions.*

ACC requests EPA also 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. *See* Response to Comments, EPA-HQ-OAR-2002-0058-2908.1, excerpt number 31; EPA-HQ-OAR-2002-0058-2740.2, excerpt number 14. 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.[8] We do not dispute that PM CEMS are newer technologies and will inevitably experience downtimes. Even the final CISWI rule provides minimum data availability requirements for PM CEMS. *See* 40 C.F.R. § 60.2730(n)(14). EPA's response that the need for minimum data availability provisions such as those in NSPS Subpart Da no longer exists due to EPA's better understanding of the need for continuous data collection and the dramatic improvement in CEMS data availability (citing Acid Rain Program) is also not persuasive. SO2 CEMS used under the Acid Rain Program would differ starkly from some of the other CEMS (Hg, HCl, PM) discussed above. SO2 CEMS are a mature technology in widespread use. Even mature CEMS technology such as SO2, NOx, and CO should be provided some reasonable amount of downtime. Therefore, ACC respectfully requests that EPA reconsider its decision to not include minimum data availability requirements, and to propose for comment a reasonable allowance for equipment downtime in 40 C.F.R. § 63.7525(a)(6).

7. EPA should reconsider the Gas 1 subcategory and include petrochemical gases; and, reconsider the opt-in provisions to allow Gas 2 units whose process gases contain H_2S concentrations similar to those in refinery fuel gas to opt-in to Gas 1 work practice requirements.

ACC believes that EPA should reconsider the opt-in provisions and take comment on including petrochemical gas in the Gas 1 subcategory. The characteristics of petrochemical gas support the inclusion of this gas in the same category as natural gas and refinery fuel gas. These gases (natural gas, refinery gas, and petrochemical gas) are clean burning fuels and are composed mainly of methane, ethane, and hydrogen.

In the proposed rule, EPA defined a "Unit designed to burn Gas 1" to include "any boiler or process heater that burns at least 90 percent natural gas and/or refinery gas on a heat input basis on an annual average."[9] *See,* 75 Fed. Reg. at 32065; § 63.7575. EPA also imposed emission limits on all units designed to burn other gases. *Id.* at 32066, Tables 1 and 2. EPA defined a "Unit designed to burn Gas 2 (other)" to include "any boiler or process heater that burns gaseous fuels other than natural gas and/or refinery gas not combined with any solid or liquid fuels." *Id.* at 32065. ACC provided significant comments on the Gas 2 approach, urging

[8] 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.

[9] We note EPA is initiating reconsideration of this issue. Notice of Reconsideration, 76 Fed. Reg. at 15267.

EPA to adopt similar Gas 1 work practices for units firing other gaseous fuels. ACC Comments at 78–83.

In the Final Rule, EPA included a new definition of "other Gas 1 fuel" that provides the ability for units firing other gaseous fuels to utilize the work practice approach of Gas 1 units if they have a Hg content of no higher than 40 ug/m3 and H_2S content no higher than 4 ppmv. *See,* § 63.7575.

EPA stated in the preamble in response to comments, "EPA has determined that to the extent that process gases are comparable to natural gas and refinery gas, combustion of those gases in boilers and process heaters should be subject to the same standards as combustion of natural gas and refinery gas." *Id.* at 15639. This is appropriate. The problem, however, is that, even though EPA found natural gas and refinery gas comparable for the pollutants in question, the Agency then set the Hg and H2S limits based on data EPA determined was available *for natural gas only*. *See,* A. Singleton & B. Lange, "Gas Specification for Industrial, Commercial, Institutional Boilers and Process Heaters at Major Sources" (Jan. 2011). ACC believes that EPA should, consistent with its conclusion regarding the comparability of these fuels, set the standard at levels achievable with *refinery gas*, with the appropriate H2S threshold. Based on the sulfur standards for refinery fuel gas under § 60.104(a)(1), the H_2S specification for other Gas 1 fuel should be similar to the standard established under that rule of 0.10 gr/dscf (162 ppmv).

8. <u>EPA should limit the scope of the energy assessment requirement to the equipment associated with the on-site regulated combustion source, and delete the maximum time requirements for the assessment.</u>

Although EPA responded to some of the concerns raised by ACC in its comments on the energy assessment provision, there are still two key issues that EPA should reconsider -- (1) EPA should limit the scope of the assessment to the equipment associated with the energy output from the on site boilers and process heaters regulated under the rule; and (2) EPA should eliminate the maximum times set forth in the rule to conduct the assessment.

A. *EPA should clarify that the scope of the energy assessment is limited to only that energy use associated with the regulated combustion emission source.*

In the proposed rule, EPA provided a definition of energy assessment as follows:

> *Energy assessment* means an in-depth assessment of a facility to identify immediate and long-term opportunities to save energy, focusing on the steam and process heating systems which involves a thorough examination of potential savings from energy efficiency improvements, waste minimization and pollution prevention, and productivity improvement.

See, § 63.7575. ACC provided extensive comments on this provision, in particular arguing that its scope was too broad. ACC Comments at 122–28. In the Final Rule, EPA provided for the first time defined "energy use system" to include energy use which in many cases is only associated with electricity use, i.e., compressed air systems, machine drive (motors, pumps, fans), process cooling, facility HVAC, building envelop(e), and lighting. *See,* § 63.7575. Because this definition appeared in the Final Rule for the first time, it is appropriate for reconsideration. The problem with this definition is that it is far too broad in that it could be read to require an energy assessment even for electricity purchased from others (such as an electric utility). Such purchase has no impact on the combustion unit fuel use or associated emissions regulated under this rule, and therefore should be outside the intended scope of the energy assessment.[10]

There are also cases where boilers or process heaters supply energy to third parties for their use. In those cases, the boiler or process heater owner/operator has no control over how the energy is utilized by those third parties. EPA needs to clarify that the energy assessment scope must only extend to facilities and equipment associated with affected units directly under the control of the affected unit owner/operator, and not extend further into any facilities or equipment not under their control.

Accordingly, we request that EPA reconsider the definition of "energy use system" to give the public proper notice and allow comment on the definition. In addition, EPA should revise Table 3, item 3.c. to read: "An inventory of major ~~**energy consuming**~~ systems **consuming energy from affected boilers and process heaters under the control of the boiler/process heater owner/operator**."

B. *EPA should delete the maximum time requirements for energy assessments.*

The proposed rule did not include any time limitations on the energy assessment. ACC's comments focused on the efforts required to undertake these assessments and other issues, but we did not comment on the length of time that such an assessment might or should take because there were no such terms in the proposed rule. Accordingly, this issue is appropriate for reconsideration because EPA failed to properly "notice" the provision in the proposed rule.

In the Final Rule, EPA specified maximum times to be spent on the assessment depending on the heat input of the boiler -- one day maximum for <0.3TBtu/yr heat input and three days maximum for 0.3 to 1 TBtu/yr heat input. *See,* § 63.7575. ACC is concerned that the failure to meet these timeframes could result in a deviation or a violation of the regulation. Moreover, ACC fails to see any benefit from such requirements. For these reasons, ACC recommends that EPA reconsider and propose for comment the elimination of these requirements.

[10] From our review of EPA's response to comments, we believe that EPA agrees that the energy assessment should be limited to the on-site boiler system and systems on site using the boiler's energy. *See,* Response to Comments, EPA-HQ-OAR-2002-0058-2702.1, excerpt number 164. "Response: The purpose of the energy assessment is to identify energy conservation measures (within the boiler system and the systems using the boiler energy). If these identified measures are implemented, the result would be a more efficient system and thus less fuel would be combusted and less emission would be emitted. We consider an energy assessment to be pollution prevention. In the final rule, we have clarified and limited the scope of the energy assessment based on the fuel use at the facility." *Id.*

9. **EPA should reconsider and revise the O_2 monitoring requirements for CO; allow for an alternative CO limit based on use of a CO CEMS; however, if an alternative CO limit based on CEMS data is not allowed, then clarify that CO CEMS data gathered to meet state regulatory requirements shall not be considered in determining compliance with CO limits established in the Final Rule.**

In the proposed rule, EPA established CO emissions limits for several subcategories of sources, with compliance demonstrated as a 3-run average for units less than 100MMBtu/hr and on a 30-day rolling average basis using a CO CEMS for units 100MMBtu/hr or greater.[11] 76 Fed. Reg. at 32015. ACC addressed these limits and the compliance methodology in its comments. ACC Comments at 24–32. ACC and others provided extensive information regarding the variability of CO emissions and the inappropriateness of setting a limit using full load stack test data, but requiring units to install CO CEMS to demonstrate compliance over all operating conditions.

In the Final Rule, EPA removed the CO CEMS requirement and instead required annual Method 10 CO performance testing to demonstrate compliance by those units with CO emission limits, and use of an O2 CEMS to demonstrate compliance on a 12-hour block average basis with the minimum O2 operating limit established during performance testing. *See*, 76 Fed. Reg. at 15698, Table 8; § 63.7525(a). These requirements appeared for the first time in the Final Rule. ACC has never had an opportunity to comment on them, and, accordingly, they are appropriate for reconsideration.

A. *EPA should revise the O_2 requirements.*

There are several technical problems with the O_2 requirements. First is the location of the O2 CEMS, and the maintenance requirements for that CEMS. The rule requires that O_2 be monitored at the outlet of the boiler or process heater and that the O_2 CEMS meet the requirements of NSPS appendix B Performance Specification 3 ("PS-3"). *See*, § 63.7525(a). We do not believe that monitoring O_2 levels in the stack or ductwork leading to the stack to ensure continuous compliance is appropriate for all units. Many existing boilers and process heaters 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 or process heater furnace outlet in a position upstream of any potential air inleakage points to avoid erroneous excess air indications. This location is also upstream of air preheaters where utilized, thus avoiding the erroneous (high O_2) indications due to inherent leakage across regenerative air preheater seals or potential tube leakage in recuperative air preheaters. For those units equipped with existing O_2 sensors and O_2 trim control systems, flue gas composition at those locations would already be used for combustion tuning and control characterization. Therefore, if O_2 monitoring was desired for continuous compliance under the Boiler MACT rule, sensing O_2 at that current location would be logical and proper from a technical perspective. However, O_2 analyzers utilized for these existing purposes

[11] We note EPA may initiate reconsideration of this issue. Notice of Reconsideration, 76 Fed. Reg. at 15267.

are not compliance CEMS meeting PS-3 requirements relative to positioning or other QA/QC requirements. They are, however, calibrated and maintained to provide reliable and safe service for combustion unit operation.

Conversely, if O_2 was sensed prior to the stack or in the stack, that would be downstream of potential air inleakage points and air preheater leakage points, thus leading to variations in readings that can impact operation and long term compliance. Where CO or NOx CEMS are utilized in the stack with O_2 or CO_2 correction, those O_2 or CO_2 readings purposely correct for variations in excess air from the furnace as well as any air inleakage or internal air heater leakage, so the impact is not of consequence from a combustion safety or direct compliance perspective. However, if it is required to actually monitor and maintain O_2 levels, then the most appropriate location for sensing that O_2 level is upstream of any potential leakage points. By definition, those locations will not meet PS-3 requirements due to their close coupled nature and use of single or multiple point sensors that are most appropriate for the application. There are some units where locating O_2 sensors in the breeching or stack is appropriate, so options should be provided to allow for optimum monitoring.

Accordingly, ACC requests that EPA reconsider these technical aspects of the new O_2 requirement and allow the option of continued use of existing O_2 analyzers and use of new O_2 analyzers of appropriate design for the application to be located in optimum positions for the particular unit involved. Requiring periodic sensor calibration would be a way to ensure accurate O_2 monitoring. The requirement of new O_2 sensors in all cases in the breeching or stack to meet PS-3 requirements, is an unjustified and additional capital and ongoing O&M expense that will not provide any constructive compliance information.

B. *EPA should provide for an alternative CO limit based on use of a CO CEMS.*

Many existing boilers and process heaters are already required to use CO CEMS under, for example, state air regulations, as discussed below. In those cases, despite how the Final Rule is written, sources could be vulnerable to someone asserting that instantaneous CO spikes could be considered "credible evidence" of deviations if those readings (under any operating conditions) exceed the CO limits (which were established in the Final Rule using reference method test data at maximum unit operating load.) It is well known that CO emissions vary widely over normal load conditions. ACC comments on the proposed rule identified those variations using EPA's data. ACC Comments at 24–33.

EPA also recognized the variation of CO with unit load as evidenced in the following response to comments:

> **Response**: EPA recognizes the inconsistency in the proposal that established a CO limit based on stack test results but required compliance demonstration with a CO CEMS. We also recognize the sensitivity of CO levels as a function of boiler load. The final rule no longer includes a requirement for a CO CEMS. Although the we appreciate the commenter suggestion to use load bin-type calculations used in the Part 75 regulations, those calculations apply to mostly very large boilers and process heaters and would be difficult to implement for load-following units that experience frequent load swings.

> Instead, EPA has included an O2 monitoring requirement in the final rule in order to ensure continuous compliance with good combustion efficiency on the unit.

Response to Comments, EPA-HQ-OAR-2002-0058-2875.1, excerpt number 11.

However, in addition to units already required to use CO CEMS, there may be units that would prefer to install CO CEMS, so an alternative CO limit would be appreciated in the Final Rule. An appropriate basis for such a CO limit would be a 30-day rolling average based on actual CO readings over the appropriate operating range. As we set forth in our comments on the proposed rule, that operating range should be when the boiler/process heater firing rate is >50% of design heat input. ACC Comments at 110–11. Including this alternative CO emission limit approach in the Final Rule would be more appropriate and cost effective for regulated facilities and regulatory authorities than requiring individual facilities to petition for alternative monitoring practices.

C. *If an alternative CO limit based on use of a CO CEMS is not allowed, EPA should then clarify that CO CEMS data gathered to meet state regulatory requirements shall not be considered in determining compliance with CO limits established in the Final Rule.*

For existing units designed to burn Gas 2 (other) gases, EPA finalized a CO limit of 9 ppmv on a dry basis corrected to 3 percent oxygen. For new units designed to burn Gas 2 (other) gases, EPA finalized a CO limit of 3 ppmv on a dry basis corrected to 3 percent oxygen. Compliance is determined by stack testing, involving three runs of one hour minimum sampling time. As set forth above, EPA deleted all requirements that would have required a CEMS for CO in the Final Rule. EPA concluded that the Agency could not set limits based on CEMS data because the available CEMS data are insufficient to set emission limits that are reflective of the best performing 12 percent of sources in the various subcategories. By contrast, a large amount of CO stack test data are available. Therefore, EPA concluded in the Final Rule that it was appropriate to use the stack test data rather than the CEMS data for setting the MACT floors for CO. 76 Fed. Reg. at 15646.

The issue of concern, noted above, is that some boilers and process heaters are already equipped with a CO CEMS in order to meet state air permitting and regulatory requirements. For example, large boilers in the Houston, Galveston, Brazoria, Texas ozone non-attainment area are required to operate a NOx, CO, and O_2 CEMS in order to meet the requirements of TCEQ Regulation 117. CO concentrations are measured at least once every 15 minutes and hourly average values are typically recorded. Thus, the CO CEMS data could be used as "credible evidence" to assert potential non-compliance with either a 9 or 3 ppmv CO limit during times of both full load and reduced load operation. This would be unfair because the Final Rule requires compliance with the CO standard (established based on stack test data) to be demonstrated through a stack test where the operating load must be at least 90% of the maximum expected operating load. Because the CO CEMS data was not relied upon by EPA in setting the CO standard, ACC requests that EPA clarify that CO CEMS data used to meet state regulatory requirements should not be considered when determining compliance with the 9 ppmv level for CO for existing sources, and the 3 ppmv level for CO for new sources, that are combusting Gas 2 fuels.

10. EPA should revise the startup/shutdown provisions to clarify their applicability.

The Final Rule contains provisions relating to startup/shutdown and to malfunctions. As set forth below, ACC requests that EPA revise these provisions as follows: for startup/shutdown, EPA should clarify that it is work practice standards that apply during startup/shutdown and not emission standards or operating limits.

In the proposed rule, EPA stated that the Agency took into account startup and shutdown periods in promulgating the standards. 75 Fed. Reg. at 32050. ACC commented that EPA should promulgate work practice standards for SSM that would allow sources a specified time period for startup, shutdown and malfunction events as long as certain procedures were followed. ACC Comments at 66–73. In the Final Rule**,** EPA requires sources "to meet a work practice standard, which requires following the manufacturer's recommended procedures for minimizing periods of startup and shutdown, to demonstrate compliance with the emission limits for all subcategories of new and existing area source boilers (that would otherwise be subject to numeric emission limits) during periods of startup and shutdown." 76 Fed. Reg. 15608, 15613, Table 2 (March 21, 2011); § 63.7500. ACC supports this significant common sense improvement from the proposed rule.

There are, however, two key issues that need to be clarified.[12] First, the regulatory language in § 63.7500 must be revised to make it clear that the emission limits set forth in Table 1 do not apply during startup and shutdown, as EPA stated in the preamble above. Rather, the work practice standards of Table 2 apply during those periods. Second, the same regulatory language must be revised to insure that the operating limits of Table 3 (operating limits for boilers with emission limits), as well as the requirements of Tables 6 (establishing operating limits) and 7 (demonstrating continuous compliance) do not apply during startup and shutdown. Again, it is the work practice standards of Table 2, and only those standards, that apply during startup and shutdown. Accordingly, ACC recommends that § 63.7500 be revised as follows:

> "63.7500(d) These standards apply at all times, except during startup and shutdown, during which time you must comply only with Table 2."

11. EPA should provide notice and an opportunity to comment on the affirmative defense provisions for malfunctions.

In the proposed rule, EPA stated that malfunctions should not be viewed as a distinct operating mode, and, therefore, that any emissions at such times did not need to be factored into development of the standards, which, once promulgated, would apply at all times. 75 Fed. Reg. at 31901-02; § 63.11201(c). ACC commented broadly that EPA's approach to SSM violated the Clean Air Act. ACC recommended that EPA should promulgate work practice standards for malfunction periods, as well as for startup and shutdown, as long as certain procedures were followed. ACC further recommended that such standards could require the development and

[12] These issues could not have been raised in comments on the proposed rule because EPA did not propose the work practice standards. These issues are of central relevance to the outcome of the rule because they deal with the key question of what standards apply during startup and shutdown. Therefore, these issues meet the requirements of Clean Air Act ("CAA") 307(d)(7)(B) for reconsideration.

implementation of an emissions minimization plan to apply during these events. *See,* ACC Comments at 27-29, 32-33. EPA rejected ACC's comments, and instead EPA promulgated an entirely new provision that allows a source to assert an affirmative defense if it exceeds a numerical emission limit during a malfunction event as long as several conditions are met. *See,* Final Rule, 76 Fed. Reg. at 15666; 40 C.F.R. § 63.7501. This new provision is not a "logical outgrowth" of the proposal because it was not a part of the proposal, so ACC did not have an opportunity to raise the issues associated with the affirmative defense discussed below. EPA stated in its March 21, 2011 Notice of Reconsideration that it intends to reconsider the affirmative defense for malfunction events for major and area source boilers and for CISWI units and we strongly support that action. 76 Fed. Reg. at 15267.

EPA should, however, reconsider not just the affirmative defense as promulgated. Rather, EPA should broaden its reconsideration to include the Agency's approach to malfunction in general. Accordingly, ACC recommends that EPA reconsider the following issues:

- EPA and case law has for decades recognized that all technologies fail at some point; therefore EPA must provide a safety valve for technology-based standards during such time periods, and this is consistent with the D.C. Circuit's *Sierra Club v. EPA,* 551 F.3d 1019 (D.C. Cir. 2008), *cert. denied,* 130 S.Ct. 1735 (2010) decision.

- EPA should promulgate work practice standards for malfunction periods, consistent with Section 112(h) of the Clean Air Act and *Sierra Club.*

- EPA's affirmative defense is not a substitute for setting emission standards for periods of malfunction for many reasons:

    - It is not clear where EPA finds the legal authority in the Clean Air Act for shifting the burden of proving (or disproving) the key elements of an alleged violation -- normally EPA would have this burden in an enforcement action.

    - Being able to assert a defense is obviously not the same as complying with specific work practice standards that take into account the limitations of technology -- sources may have to conservatively report a violation or certify noncompliance until there has been an enforcement action in which the source has successfully asserted the defense. This is unacceptable.

    - EPA limits the affirmative defense to "civil penalties." First, it is not clear what this means. Does it cover civil administrative penalties under CAA § 113(d)? Does it cover noncompliance penalties under CAA § 120? How does the defense apply to state and local governments and citizen suits? Finally, EPA specifically states that the affirmative defense is not available for claims for injunctive relief. EPA does not provide a rationale for not extending the defense to injunctive relief, and there is no apparent reason why it should be so limited.

- The affirmative defense establishes nine criteria (with some further subparts) that a source must satisfy in order to assert the defense, together with stringent notification requirements. ACC believes that many of these criteria are inappropriate or so vaguely worded that they will vitiate the use of the defense, and ACC will provide detailed discussion of the criteria in its comments on reconsideration.

Technical Corrections

Table 8, Final Rule 76 Fed. Reg. at 15697-15698.
The wording in Table 8 is not consistent and therefore could be confusing. Item 8.c. includes the word "block" in stating the requirement to "Maintain the 12-hour block average oxygen content…" However, other similar requirements do not include the word "block" in the compliance requirement statement. We recommend that EPA revise the following items in Table 8 as noted below for clarity and to reduce potential confusion:

3.c. "Maintaining 12-hour **block** average pressure drop…"

4.c. "Maintaining 12-hour **block** average pH…"

5.c. "Maintaining 12-hour **block** average sorbent or carbon injection rate…"

6.c. "Maintaining 12-hour **block** average total secondary electric power input…"

9.c. "Maintaining 12-hour **block** average operating load…"

Section 63.7525(d)(4)
Section 63.7525(d)(4) requires determination of 4-hour block averages of all recorded readings, whereas Table 8 requires compliance to be demonstrated using 12-hour block averages. The 4-hour statement is believed to be an error and should be corrected to read:

"(4) You must determine the **12**-hour block average of all recorded readings…"