ABMA
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Via Facsimile and Electronic Mail
Environmental Protection Agency
EPA Docket Center (EPA/DC)
Mail code: 2822T
1200 Pennsylvania Avenue, NW
Washington, DC 20460
Docket ID No. EPA-HQ-OAR-2006-0790

Re: Comments of the American Boiler Manufacturers Association on the Proposed National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial and Institutional Boilers

Dear Sir/Madam:

On behalf of its member companies, the American Boiler Manufacturers Association ("ABMA") herein provides comments to the Environmental Protection Agency ("EPA") regarding EPA's proposed National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial and Institutional Boilers, 40 C.F.R. Part 63, Subpart JJJJJJ, published at 75 Fed. Reg. 31896-31935 (June 4, 2010) (the "Proposed Area Source Rule").

Description of the ABMA

The ABMA is a national nonprofit trade association of commercial, institutional, industrial and electricity-generating boiler system manufacturing companies. Founded in 1888, ABMA is dedicated to the advancement and growth of the boiler and combustion equipment industry. The organization provides a common ground for information sharing and communication among manufacturers, their customers, government and the public. With more than one hundred member companies, ABMA is the only association of boiler, combustion, heat recovery, environmental, controls and instrumentation equipment and systems (>400,000 Btu/hr heat input) manufacturers. ABMA's member companies design, fabricate, install, retrofit and maintain the highly fuel-flexible boiler technologies that generate the steam and hot water that powers and comforts America. ABMA is also allied with and counts as participating members industry suppliers and vendors, repair and after market shops, and boiler owners and operators committed to the design, fabrication, installation and operation of safe, clean, efficient and reliable steam and hot water systems. In light of its broad and diverse memberships and

affiliations, ABMA's comments represent an industry-wide consensus rather than the perspective of a single company.

ABMA's member companies maintain a high level of technical expertise with respect to all aspects of boiler and boiler-related equipment design, performance, emissions and emissions control. ABMA has therefore reviewed the Proposed Area Source Rule from a technical perspective, to determine whether the emission limits, goals and objectives of the rule are technically achievable and appropriate. To the extent such limits are not achievable through combustion alone, ABMA has sought to determine whether changes in fuel, control equipment or system replacement would be required and whether such measures would be appropriate given current technical constraints. ABMA's comments are based on its members' broad base of experience and expertise with respect to these issues, and are offered to EPA to ensure that the Proposed Area Source Rule is consistent with currently available and effective equipment and technologies provided by ABMA's member companies.

General Comments

1. In establishing achievable MACT emission standards for area sources, EPA should consider current manufacturer-guaranteed emission levels. In the preamble to the Proposed Area Source Rule, EPA notes that pursuant to the directives of Section 112(c)(6) of the Clean Air Act, it has developed maximum achievable control technology ("MACT") standards for mercury emissions from coal-fired area source boiler and for polycyclic organic material from all area source boilers. 42 U.S.C.A.§7412(c)(6). MACT is enumerated in section 112(d) of the Clean Air Act, which requires EPA to establish emission standards based on the *"maximum degree of reductions in emissions of the hazardous air pollutants . . . that the Administrator, taking into consideration the cost of achieving such emission reduction . . . determines is achievable for new or existing sources in the category or subcategory to which such emission standard applies . . ."* 42 U.S.C.A. §7412(d). In establishing "achievable" emission standards, section 112(d)(3) directs EPA to examine the emission control that is "achieved in practice" by top performers based on "emission information" available to the agency. ABMA acknowledges EPA's efforts to comply with the directives of Section 112 by evaluating stack testing and continuous emission monitoring system ("CEMS") data from boilers within the subcategories identified in the Proposed Area Source Rule. However, such testing and CEMS information may not be representative of the range of boiler design types within each subcategory, may not consider variable performance across the range of firing rates, and may not reflect practical operational constraints such as startup and shutdown periods, load swinging and other issues.

To evaluate these issues comprehensively, ABMA suggests that EPA should consider information that is available from boiler, burner, and emissions control equipment manufacturers, including currently available equipment design and guaranteed emission levels. Specifically, emission limits that are identified by EPA as "achieved in practice" should not be inconsistent with the most up-to-date equipment emission guarantees offered by equipment manufacturers. ABMA does not suggest that MACT emission levels should be equivalent in all cases with manufacturer guarantees. However, boiler, burner and control equipment manufacturers base guaranteed performance levels on a number of considerations that may be

beyond the scope of EPA's data set. Therefore, emission levels set well below the range of guaranteed performance may not be "achievable" in practice for all purposes. Further, regardless of mandated emission standards, equipment manufacturers cannot provide commercial warranties or guarantee an emission level associated with any product or technology, where the emission standard cannot be achieved continuously over a defined period of time using currently available technology. In short, due to commercial liability considerations, no boiler, combustion equipment or emissions controls manufacturer will sell technology for which the manufacturer cannot provide guaranteed performance and, conversely, no owner/operator will buy technology for which a performance guarantee is not provided. Without such guarantees, boiler owners and operators maybe left in a difficult position, and without a clear path to compliance. For these reasons, and where appropriate, ABMA has offered herein information and considerations that may impact manufacturers' emission guarantee levels for various pollutants and boiler types as an additional source of "emissions information" that may be considered by EPA in setting standards pursuant to Section 112.

2. In establishing achievable MACT emission standards for area sources, EPA should consider the multiple rules and emission standards that affect the full range of boilers and combustion equipment. As EPA is aware, many existing and new boilers are subject to multiple federal and state rules and emissions standards which may be inconsistent and/or conflicting. The technical implications to piece-meal rulemaking, such as a failure to consider the operational impacts of multiple emission standards, may adversely affect overall boiler performance as well as the goals of the Clean Air Act, and may needlessly drive up the cost of compliance. As an example, the stringent emission limits for carbon monoxide ("CO") set forth in the Proposed Area Source Rule will affect sources' ability to meet low nitrogen oxides ("NOx") emissions because minimizing CO in the combustion system is a goal that is opposed to minimizing NOx in most boiler burners. Because boiler NOx emissions are generally regulated pursuant to control or emission standards implemented by state agencies, EPA may not have fully considered the impacts of such varying NOx control requirements on CO performance. Conversely, in some applications, such as in combustion turbine / heat recovery steam generation systems, CO control may adversely affect selective catalytic reduction for NOx control and particulate emissions due to the oxidation of NO to NO2 and SO2 to SO3 and/or SO4. Inconsistencies in requirements for NOx and CO may needlessly cause boiler owners and operators to incur control costs that outweigh the relative environmental benefits, and may affect boiler performance.

3. In establishing achievable MACT emission standards for area sources, EPA should address the anticipated startup, shutdown and malfunction conditions that may be experienced across the wide range of boiler designs and applications. To the extent that emission standards must apply during periods of startup, shutdown and malfunction, they must be set in a manner which adequately accounts for anticipated emissions during those conditions. ABMA is concerned that the data on which EPA has relied does not adequately represent considerations that may affect such emissions, such as boiler size, usage of flue gas recirculation ("FGR"), steam pressure and temperature. These issues are particularly relevant to startup conditions, which are reasonably anticipated and can be evaluated in the standard-setting

process. For example, the following factors should be considered in relation to CO emissions during startup:

- During cold start, furnace temperature is low and higher CO emissions will result;

- High pressure boilers take longer to come up to temperature;

- Super heated steam applications take longer to reach their normal operating conditions;

- Low NOx, high FGR applications have very low air velocities at the burner during cold start, because FGR cannot be introduced to the burner before it reaches a certain temperature, thereby reducing volumetric flow and resulting in higher CO emissions;

- A typical cold start CO emission level that may range up to 400 ppmvd or higher on oil, and the following wide range of boiler warm-up periods based on boiler type may result in significantly higher average CO emissions than experienced at steady-state operation:

  - Firetube boilers: 1-4 hours

  - Industrial watertube boilers (150 psig): 3-6 hours

  - Super heated industrial watertube package boiler: 4-8 hours

  - Super heated field erected boilers – 8 hours or more

EPA's preamble to the Proposed Area Source Rule does acknowledge an attempt to incorporate startup and shutdown emissions through its consideration of daily or monthly average CEMS data from the best performing units. However, EPA has not demonstrated that its data set adequately addresses the variability in startup length and associated emissions experienced in boilers of various design and load requirements. Therefore, ABMA believes that EPA should: (1) allow a period of time for startup, based on boiler type, during which emissions limits would not apply; (2) establish an alternative emission limit for startup periods based on boiler types within a subcategory and their load; or (3) review the data set and the anticipated startup conditions of various boiler types to ensure that the emission limits set for each subcategory are representative of multiple boiler designs and emission variability within the subcategory. The alternatives for defining reasonable emission standards for startup conditions should extend to startups occasioned by the range of circumstances, such as cold start after a period of scheduled non-operation, as well as startup occurring after a malfunction during which cold-start parameters often apply. Additionally, EPA should extend similar consideration to emissions variability during shutdown periods. During these periods, considerable volumetric post- and pre-purge air change requirements serve to cool boilers down in an attempt to relieve the combustion chamber of unburned fuel and of flue gases prior to re-ignition sequence.

ABMA also supports a limited allowance for malfunction periods. The term "malfunction" should be more precisely defined to include the variabilities of malfunction. Malfunction can range from the need for immediate and complete shutdown to malfunctions like an interruption in fuel supply or an inoperative CEMs that will require only a short downtime. A plant should not be required to completely shutdown due to a malfunction of the boiler, burner or boiler-related equipment. Once defined, a malfunction should be regulated by alternative limits applied during the time it takes to complete corrective action and get the boiler back to normal operational mode.

4. If properly designed to reflect the broad range of boiler designs and operational conditions, as well as manufacturers' emission guarantee levels, the Proposed Area Source Rule will stimulate the creation of jobs in the boiler and boiler-related equipment industry. To the extent that EPA develops an Area Source Rule rulemaking that is achievable in practice for boiler owners and operators**,** the proposal will create solid, well-paid, professional, skilled and unskilled manufacturing jobs attendant to the upgrade, optimization and replacement of existing boilers around the United States. In addition, service jobs associated with the installation and maintenance of these systems, as well as service jobs associated with required tune-ups and energy assessments will be created. These jobs will be significant contributions to our local, state and national economies – contributions that must not be overlooked or minimized.

Specific Comments

1. Comments Relating to Carbon Monoxide

ABMA is concerned that the emission limits identified in the Proposed Area Source Rule for CO are not achievable in practice, because they do not fully reflect the broad range of design and operational considerations that affect CO emissions. Further, although EPA appears to assume that Good Combustion Practices ("GCP") will be adequate for CO control, ABMA believes that add-on controls will be necessary to reduce CO within the range of proposed levels. ABMA offers the following specific comments for CO:

- EPA has not adequately identified its basis for using CO as a surrogate for polycyclic organic matter ("POM"). ABMA acknowledges a correlation between CO and organic HAPs; however, ABMA is not aware of any relevant testing data that correlates the relationship between HAPs and CO when operating at CO levels less than 100 ppm. By contrast, data from the Petroleum Environmental Research Forum Project 92-19 provides some of the most complete data examining the relationship between CO and HAPs during gas firing. While there is a fairly linear correlation between decreasing CO and decreasing HAPs at higher levels, once the CO values fall under 100 ppm, further reduction of CO did not provide any substantial correlating reduction of HAPs. Based on this data, it can be concluded that during gas firing the reduction of CO from 100 ppm to 1 ppm may not create any incremental benefit in terms of HAP reductions. Without any data to the contrary, this relationship between CO and HAPs should also be applied to oil-firing, where EPA has not demonstrated that a significant HAP reduction would occur at CO levels below 100 ppmvd.

- EPA's data set for establishing a MACT standard for CO emissions from oil-fired units is inadequate. Out of an estimated 168,000 oil-fired units that will be affected under the Proposed Area Source Rule, EPA's MACT floor evaluation was based on emissions data from only 68 units, and permit limit information for 56 others. ABMA is concerned that this data set is too limited, in light of the many types of boiler design and operating scenarios which may affect CO emissions.

- EPA did not adequately account for load variability in establishing the proposed CO limit of 1ppm for oil-fired units. As a general matter, stack testing data is not representative of load variability because stack tests are conducted at steady state loads where CO is minimized (i.e. 50-90%). By contrast, CO will increase at lower firing rates due to the decreased mixing energy of the flame and the reduced temperature in the furnace. (This is more pronounced in single-burner boilers, since the burner needs to cover the entire turndown range, than for multiple-burner boilers in which turndown can be achieved by taking burners out of service.) It is common for boiler burners to be required to operate across an 8:1 turndown range (down to 12.5% firing rate) on oil. CO may also increase at higher firing rates, when the flame fills the furnace and approaches the tube walls where temperatures become too cool to promote CO oxidation. CO may also vary dramatically when a boiler is modulating load to follow a steam demand. This results from metered control systems which allow air to lead fuel on increasing load, and fuel to lead air on decreasing load. Fuel-lean operation during transient load conditions reduces flame temperature and increases CO production. As a general matter, the faster a unit is required to change load, the greater the magnitude of CO increases.

- ABMA believes that the Proposed Area Source Rule CO limits of 2 ppmvd @ 3% oxygen for existing (large) oil-fired boilers and 1 ppmvd @ 3% oxygen are not achievable using GCP. As noted above, minimizing CO in the combustion system is inconsistent with minimizing NOx emissions. Fuel staging and FGR technologies aim to lower the overall temperature of the flame, making it longer and wider. By contrast, minimization of CO requires the flame to be more concentrated to the center of the furnace. While burner companies are generally able to balance NOx and CO minimization goals by a combination of fuel staging and turbulence, a CO limit of 1 ppm cannot be achieved on this basis. This is especially true at low firing rate (i.e. <25%), because excess air cannot be regulated tightly at these firing rates. Excess air at low loads may "chill" the flame, causing incomplete combustion and increased CO emissions. For a CO limit to be achieved using GCP while firing oil, ABMA offers the following recommendation based <u>on manufacturer guarantees of performance</u>:

    - For boilers firing both fuel oil and natural gas: a CO limit of 50 ppm.

- Operation of oxidation catalyst for CO control would be subject to several design constraints. As an initial matter, oxidation catalyst performs optimally at temperatures of 600ºF and above. Small boilers operating at turndown ratios may not be able to meet these temperatures. In particular, package boilers operating at low pressure and low load may

experience low flue gas temperatures.[1] While an increase in volume and pressure drop may compensate for lower temperature, capital costs and operating expenses may increase. For example, a typical boiler producing 80,000 pounds of saturated steam is assumed to use a fan (at sea level) that moves 18,000 cfm at 14 inches of water column, and its energy consumption is 39.4 kw. The addition of a CO oxidation catalyst will add an estimated 2 inches water column to the draft losses of the system. This figure is based on typical design criteria, plus the need to compensate for low flue gas temperature. To the extent that the air moving equipment is capable of overcoming the added draft losses, the static pressure increase would result in a new energy usage of 45 kw, or 14% increase. Other costs associated with the use of oxidation catalyst include the need for a near perfect flow distribution, which require flow straightening material or large amounts of catalyst material. The formation of sulfates is also a concern, because they may bond to the substrate of the oxidizing catalyst and create a potential for a sulfuric plume of SO_3, which may condense to form sulfuric acid. Further, in some field erected units, the installation of oxidation catalyst can reduce boiler heat exchange surface for lack of an adequate "window" for placement. Based on all of the above, oxidation catalysts may present technical and economic constraints that were not adequately evaluated by EPA. Further, even at optimal temperatures, use of an oxidation catalyst may not be sufficient to meet a 1 or 2 ppmvd emission level for CO. As an alternative, ABMA recommends a CO limit in the 5 ppm range where oxidation catalyst is used at optimal flue gas temperatures (>600ºF).

- Good combustion is the result of the three T's: time, temperature and turbulence. CO emissions from biomass-fired boilers and energy systems will vary due to the wide range in the moisture content of the biomass fuels being fired and the design of the furnace and combustions systems. An increase in the moisture content of the biomass fuel results in a lower adiabatic flame temperature and therefore increased CO. Advances in equipment design, including water-cooled grates that allow for increase pre-heated air temperature, has helped to decrease CO and advanced overfire/secondary air systems provide turbulence and oxygen in strategic areas of the furnace to improve combustion and subsequently reduce CO. The CO emissions from existing facilities routinely vary between 450-700 ppm @ 3% oxygen under the best of operating conditions. Interruption in fuel feed can increase CO emissions to levels above 1000 ppm. Even with upgrades to combustion controls and overfire/secondary air systems, there are no guarantees that the proposed CO limit of 160 ppmvd @ 7% oxygen would be obtainable for a large population of older boilers due to specific operating requirements and existing combustion system and furnace design limitations.

- In the past decade, CO permit limits have decreased. In order to achieve these lower CO limits, new units are designed with (1) larger furnaces which result in increased retention time; (2) increased grate areas which result in lower upward furnace velocity; (3)

[1] The following represent typical outlet flue gas temperatures for package boilers:

	25% MCR	100% MCR
125 psig 3 pass FT	380F	460F
125 psig 4 pass FT	365F	400F
300 psig saturated IWT	454F	628F
750 psig 730F superheated IWT	559F	807F

advanced water-cooled grate designs which enable higher combustion air temperatures for improved combustion of high moisture content biomass fuels; and (4) advanced overfire/secondary air systems which reduce the formation of CO and NOx. Therefore, the proposed CO value of 100 ppmvd @7% oxygen for new biomass-fired units may be obtainable for a limited range of biomass fuels and combustion systems, but in most cases, an oxidizing catalyst will be required. ABMA is aware of CO reduction catalysts installed on at least two (2) biomass facilities. The results have been reported to be successful. However, these particular units both fire a consistent chipped wood and bark fuel with moisture contents between 45-50%, <3% ash with low percentages of alkali constituents in the ash and uniform fuel particle size distribution sizing on an annual basis. Also, because they serve electrical generating facilities, boiler operations are relative stable and steam flow does not fluctuate. It is unknown how these facilities would perform given the fluctuations in operating conditions that are inherent with most industrial boilers.

- For an area source where a CO catalyst is required, there is an additional issue EPA should consider. If the NOx emission limit requirement (not regulated under proposed MACT) is such that selective non-catalytic reduction ("SNCR") is required, then the nitrogen in the ammonia slip will be oxidized at the CO catalyst into NOx. This means that the SNCR needs to be sized to reduce NOx at the boiler outlet to a value lower than the permitted requirement with low ammonia slip. Essentially, 1 ppm of ammonia will make an additional ppm of NOx at the stack if it passes over a CO catalyst. Therefore, NOx at the boiler outlet must be low enough so that the new NOx made at the CO catalyst from the oxidation of the ammonia will not exceed the overall NOx emission requirement. To make this system work requires very close coordination between the boiler designer and the SNCR supplier. If the requirements for NOx control and CO control cannot be balanced as outlined in the foregoing, then SCR may be required even if the NOx requirement is not too difficult. This may be an unintended and possibly very costly consequence of the proposed Area Source rule. There is more than one way to integrate a SCR catalyst into an area source boiler system. Typically the CO catalyst comes first followed by a SCR if both systems are required. However, to meet the proposed Area Source requirements one other strategy that may be useful is to put a limited quantity of SCR catalyst before the CO catalyst with the express purpose of using up the ammonia in the flue gas. With this system, one will obtain an additional reduction in NOx, as well. Again, however, if the ammonia slip required to reduce the NOx is too high, a full SCR will be required after the CO catalyst. It is therefore ABMA's contention that the Area Source CO requirement for biomass boilers with stoker combustion technology is difficult with which to comply, definitely costly, and, in our experience, unfounded in good industry practice.

- Noting the differential between the proposed Area Source and Major Source MACT limits for CO for biomass-fired units, 560 ppm at 3% O2 is the equivalent of approximately 435 ppm at 7% O2. Generally, ABMA would be comfortable meeting the 435 ppm number with a stoker biomass unit. However, the limit for CO for a Major Source for a biomass stoker fired boiler is significantly less stringent than the CO requirements for units permitted as an Area Source, where the proposed CO limits are 100 ppm at 7% O2 for new sources and 160 ppm at 7% O2 for existing sources. To meet these limits, as discussed above, a

CO catalyst would be required for biomass-fired boilers using stoker combustion technology. [Note: fluidized bed units have a different standard and CFBs can usually meet the limit on CO for several reasons, including the enormous heat sink they have with the bed material, the additional time at temperature for the fuel in the bed, the attrition of the bed material on the fuel particles constantly exposing new surface to the combustion process, and generally good mixing.]

2. Comments Relating to Monitoring and Continuous Emission Monitoring Systems Requirements

- ABMA believes that the monitoring and CEMS requirements of the Proposed Area Source Rule should be clarified. As an initial matter, ABMA recommends that EPA evaluate the technical feasibility of in-situ measurements at the very low emission levels identified in the proposed rule. To the extent that EPA has not done any such evaluation, ABMA recommends that EPA contact CEMS manufacturers to ensure that CEMS will provide an accurate and feasible tool for compliance.

3. Comments Related to Boiler Tune-up Requirements

- ABMA acknowledges the proposed requirements for boiler tune-ups set forth in proposed 40 C.F.R. §63.11223. While maintenance, repair and tune-up of boilers and combustion equipment in the >400,000 Btu/hr sector do have characteristics in common, ABMA notes that every boiler system is different depending on overall design, operational characteristics and use. Each boiler system in this sector is designed to a specific application; "cookie-cutter" designs do not apply to the non-residential boiler sector. Given such variability in design and operation, and the very real issue of safety as it pertains to (1) doing work with highly technical combustion systems and (2) operating those systems post-tune-up, it is important for tune-ups to be conducted by companies and personnel with the highest standards of technical training and practical expertise in addressing issues of maintenance, repair and optimization of boiler systems. The manufacturers of boilers, burners, or boiler components are a logical source of expertise, as are representatives and boiler repair companies that have documented arrangements with manufacturers. Further, tune-ups should be conducted in accordance with manufacturer guidelines and recommendations in order to preserve technical warranties and guarantees.

4. Comments Related to Energy Assessment Requirements

- EPA has requested comment on its requirement for existing boilers located at major source facilities to undergo an energy assessment to identify cost-effective energy measures. ABMA supports EPA's proposal that such assessment would be conducted by professionals and/or engineers that have relevant expertise, such as those who have successfully completed the Department of Energy Qualified Specialist Program, or a professional engineer certified as a Certified Energy Manager by the Association of Energy Engineers. ABMA suggests that such qualified personnel may also include other persons who are equally knowledgeable about the equipment and processes that are the subject of the assessment.

- ABMA requests that EPA clarify the scope of the required energy assessment. As set forth in Table 2 of the Proposed Area Source Rule, the scope of the energy assessment could be interpreted to extend beyond the affected boiler. ABMA recommends that the scope of the energy assessment should be limited to the boiler and directly associated components such as the feed water system, combustion air system, fuel system (including burners), blow down system, combustion control system and heat recovery of the combustion fuel gas. The publication of a standard procedure would ensure uniform and comparable results for all plant energy assessments. It is also of utmost concern that the boiler owner/operator has full faith that the qualifications of any provider of assessment services have been sufficiently vetted to assure that fly-by-nighters, scammers or those out to make a quick buck as a result of mandated federal requirements be quickly identifiable and avoidable. Toward that end, ABMA would recommend that providers of energy assessment services should have no financial interest in any company that might profit from the assessment's findings – in other words, conflicts of interest should be avoided wherever possible.

In conclusion, establishing HAP emissions limits for industrial, commercial and institutional boilers is not a simple exercise. Not only are there vastly differing design concepts within each boiler type, there are significant variables associated with each design's specific application, operation and fuel – singly and in concert with other boilers. Although design can anticipate many of those variables, the hourly operation of a boiler is subject to many unanticipated occurrences. While ABMA understands the importance of uniformity, it is important that EPA understand the diversity of the equipment and systems it is attempting to regulate and the role and importance of performance guarantees in addressing that diversity of design and operation. As the sole trade association representing the interests of its membership in the >400,000 Btuh (heat input) boiler manufacturing industry, ABMA has tried to shed a light on that design and operational diversity and this industry's ability to achieve the emissions levels proposed. ABMA appreciates EPA's consideration of these comments, and is more than willing to provide additional information as may be appropriate at EPA's request.

Very truly yours,

W. Randall Rawson
President/Chief Executive Officer