National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers; Proposed Rule
(2015 Area Source Proposed Reconsideration Rule)

EPA–HQ–OAR–2006-0790

Comments of Council of Industrial Boiler Owners (CIBO) and American Chemistry Council (ACC)

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I. INTRODUCTION

The Council of Industrial Boiler Owners and American Chemistry Council (collectively “Commenters”) appreciate the opportunity to comment on the Environmental Protection Agency’s (EPA) proposed reconsideration of the national emission standards for hazardous air pollutants (NESHAP) for area source industrial, commercial and institutional (ICI) boilers. 80 FR 2871 (Jan. 21, 2015) (2015 Area Source Proposed Reconsideration Rule).

ACC represents the leading companies engaged in the business of chemistry. ACC members apply the science of chemistry to make innovative products and services that make people’s lives better, healthier and safer. ACC is committed to improved environmental, health and safety performance through Responsible Care® common sense advocacy designed to address major public policy issues, and health and environmental research product testing. The business of chemistry is a $812 billion enterprise and a key element of the nation’s economy.

CIBO is a trade association of industrial boiler owners, architect-engineers, related equipment manufacturers, and University affiliates representing 20 major industrial sectors. CIBO members have facilities in every region of the country and a representative distribution of almost every type of boiler and fuel combination currently in operation. CIBO was formed in 1978 to promote the exchange of information about issues affecting industrial boilers, including energy and environmental equipment, technology, operations, policies, laws and regulations.

Commenters’ member companies own and operate many boilers that will be subject to this rule.

II. BACKGROUND

In August 2013, EPA noticed reconsideration of several issues and now proposes additional revisions to the Area Source boiler rules. 80 FR 2871 (January 21, 2015) (2015 Area Source Proposed Reconsideration Rule).

While the reconsideration rulemakings proceeded, parties challenged the 2011 and 2013 Area Source Final Rules in DC Circuit Court. Those challenges are consolidated in ACC v. EPA (No. 11-1141) and as of February 2015 are briefed and pending oral argument before the Court.

Commenters submit these comments on the 2015 Area Source Proposed Reconsideration Rule.

III. COMMENTS

A. STARTUP AND SHUTDOWN PROVISIONS

EPA specifically granted reconsideration of the startup and shutdown provisions and proposes significant revisions to those provisions. This most recent iteration is an improvement over earlier versions, including for example the new definition of “useful thermal energy.” EPA directly addressed comments by regulated sources on its prior Area Source boiler regulation and thereby proposes to improve the achievability of the rule with the current rulemaking.

In the preamble to the proposed rule, EPA expressly requests comment on certain aspects of the startup and shutdown provisions. Our organizations and members have substantial experience and knowledge regarding ICI boiler startup and shutdown periods, which should be considered before finalizing the 2015 Area Source Proposed Reconsideration Rule.

EPA agrees that “the startup period should not end until such time that all control devices have reached stable conditions.” 80 FR 2875. However, EPA then arbitrarily limits the startup period to four hours after the start of supplying useful thermal energy, even for the boilers that need more time for a control device to reach stable conditions. EPA’s reliance on data from electric generating units (EGUs) in an entirely different source category subject to the Mercury and Air Toxics (MATS) rule does nothing to ensure that boilers subject to this rule can complete a startup period within four hours without posing a safety or compliance risk. EPA then asserts – incorrectly – that the ICI boiler data in the record supports a four hour limit on the startup period.
for area source boilers. Many ICI boilers will need more than four hours to meet EPA’s criterion that “all control devices have reached stable conditions” before the end of the startup period. We ask that EPA allow source owners/operators more time during startup and the flexibility to work with their permit authorities to establish a source-specific startup period when the default startup period is insufficient for a particular boiler configuration.

After acknowledging comments expressing that safety must be the primary concern regarding startup, EPA inexplicably proposes to base the starting point on what was achieved by the best performing 12 percent of existing EGU sources without regard to whether that reflects the time boilers need to reach safe and stable conditions. See 80 FR 2875. EPA misapplies the 112(d)(3) (top performing 12 percent) existing source MACT methodology here. The startup period is not an emission limitation or standard to be set by the top performers. It would be reckless for EPA to ignore 88% of the sources regulated when evaluating the time period necessary to ensure safe and stable startup operations. EPA’s apparent rush to mark the end of startup must not push any boiler into unsafe or unstable operating conditions.

The reason the puzzle of regulating startup and shutdown has not yet been solved is because startup and shutdown are defined by the facts of boiler operation, facts which vary from unit to unit and that cannot be changed to meet regulatory commands. These facts are reflected in startup curves prepared by boiler manufacturers that reflect the incremental increase in temperature that a unit can safely accommodate. EPA’s proposed alternate definition of “startup” makes some progress by defining the startup period after a shutdown to include the time a boiler needs to come up to temperature before it starts generating useful thermal energy. This part of the startup period comes before the clock starts on EPA’s proposed 4-hour period and it accommodates many of the boiler differences that affect the length of the startup period. Boilers need this flexibility to accommodate differences in the size, type, age, condition, and fuels used during startup. The time for startup may also change seasonally as cold atmospheric temperatures can extend the time needed to incrementally bring the unit up to temperature. EPA’s proposed alternate startup definition properly recognizes and accommodates this diversity of boilers.
Some boilers, however, start generating useful thermal energy more than four hours before they reach safe and stable operating conditions. For these units, the “startup” definition should include provisions for a simple process for establishing source-specific startup periods longer than four hours as may be needed to safely accomplish startup to stable conditions. We suggest a simple, sensible, safe and environmentally protective solution: define startup to be the point at which stable operating load is reached for the specific boiler.

1. **Startup Definition**

In the February 2013 Area Source Final Reconsideration Rule, EPA defined startup to include the period commencing when fuel is fired in a boiler and ending when heat or steam is supplied for any purpose. 40 CFR § 63.11237. EPA proposes an alternate definition that defines startup as:

(2) The period in which operation of a boiler or process heater is initiated for any purpose. Startup begins with either the first-ever firing of fuel in a boiler or process heater for the purpose of supplying useful thermal energy (such as steam or heat) for heating, cooling or process purposes, or producing electricity, or the firing of fuel in a boiler or process heater for any purpose after a shutdown event. Startup ends four hours after when the boiler or process heater makes useful thermal energy (such as heat or steam) for heating, cooling, or process purposes, or generates electricity, whichever is earlier.

80 FR 2884; 40 CFR § 63.11237.

This alternate definition is EPA’s acknowledgement “that the startup period should not end until such time that all control devices have reached stable conditions. 80 FR 2875. EPA cites to CIBO comments on the prior Area Source rule and to EGU performance data to support this alternative definition, which allows steam and heat to be put to use for a limited period of time during the startup period as boiler and control devices reach safe and stable conditions.

While it improves on the first “startup” definition, the arbitrary 4-hour limit is not broad enough to address the wide range of startup scenarios at regulated boilers as described in more detail below.
EPA states that it has very limited data on the number of hours ICI boilers need to reach stable conditions, specifically, data from 13 units and information submitted by CIBO. 80 FR 2875. The CIBO data provides startup and shutdown information for 76 boilers, so EPA presumably has data for a total of 89 boilers. This is an extensive data set specifically derived from the sources in the category regulated by this rule, and is therefore a much sounder basis on which to discern the number of hours needed to reach stable operation and define startup.

EPA also incorrectly states that the CIBO data supports EPA’s regulatory conclusions. The CIBO data clearly shows that a large number of ICI boilers will not reach stable load within 4 hours.

In 2014, CIBO sent an informal survey to members to gather information on startup times for different designs of units subject to the Area Source rule. We gathered information for a total of 72 solid fuel units and 4 liquid units and that information was provided to EPA (See Attachment A CIBO Startup Survey Summary). The following table shows the type of units for which information was gathered:

<table>
<thead>
<tr>
<th>Boiler Type</th>
<th>Primary Fuel</th>
<th>Control</th>
<th>Responses Received (# units)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Circulating FBC</td>
<td>Coal or coal/biomass</td>
<td>Baghouse</td>
<td>20</td>
</tr>
<tr>
<td>Bubbling FBC</td>
<td>Coal</td>
<td>Baghouse</td>
<td>3</td>
</tr>
<tr>
<td>Pulverized Coal</td>
<td>Coal</td>
<td>Baghouse</td>
<td>2</td>
</tr>
<tr>
<td></td>
<td></td>
<td>ESP</td>
<td>11</td>
</tr>
<tr>
<td>Stoker or Hybrid Suspension Grate</td>
<td>Coal</td>
<td>Baghouse</td>
<td>7</td>
</tr>
<tr>
<td></td>
<td>Biomass</td>
<td>Baghouse</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>Coal</td>
<td>ESP</td>
<td>6</td>
</tr>
<tr>
<td></td>
<td>Biomass</td>
<td>ESP</td>
<td>15</td>
</tr>
<tr>
<td></td>
<td>Biomass</td>
<td>Scrubber</td>
<td>5</td>
</tr>
<tr>
<td>Fuel Cell</td>
<td>Biomass</td>
<td>ESP</td>
<td>2</td>
</tr>
<tr>
<td>Liquid</td>
<td>Liquid</td>
<td>Any</td>
<td>4</td>
</tr>
<tr>
<td><strong>Total Responses</strong></td>
<td></td>
<td></td>
<td><strong>76</strong></td>
</tr>
</tbody>
</table>
CIBO asked members for information on cold, warm, and hot startup times, where a cold startup indicated that the unit had been offline for at least 120 hours, a warm startup indicated that the unit had been offline for 8 to 120 hours, and a hot restart indicated that the unit had been offline less than 8 hours. CIBO asked the average time for the unit to come online after first ignition of the startup fuel, the average time to reach 25% load after coming online, and the average time to attain stable operation of both the combustion unit and its emissions controls after reaching 25% load. CIBO focused on 25% load because that was one of the criteria that EPA was once considering for defining the end of startup. The responses varied by fuel, unit design, and control device. The data shows, in summary, that 4 hours is not enough time for all designs of boilers and all control devices to achieve safe and stable operation.\(^1\)

CIBO’s data indicate that on a cold or warm startup, the total time for fluidized bed boilers to reach stable operation ranges from 6.5 to 45 hours, for pulverized coal the total time is 7 to 40 hours, for stoker or hybrid suspension grate units the total time is 2.2 to 32 hours, for fuel cells the total time is 22 to 36 hours, and for liquid units the total time is 7.5 to 11 hours. What is not clear from these data is the point at which a unit starts to generate useful thermal energy, which starts the 4-hour clock in EPA’s alternate definition of “startup.”

CIBO collected information regarding the time required to reach stable conditions after achieving 25% load. While 25% load does not equate to useful thermal energy for all units, it is a reasonable surrogate for the point at which useful thermal energy could be available for some units. Therefore, CIBO’s 25% load data is a reasonable indicator of the time necessary for units to move from useful thermal energy to safe and stable conditions. Fluidized bed boilers can take up to 26 hours to reach stable conditions after reaching 25% load, pulverized coal boilers can take up to 5 hours to reach stable conditions after reaching 25% load, stoker and hybrid suspension grate type units can take up to 20 hours to reach stable conditions after reaching 25% load, and fuel cell units can take up to 26 hours to reach stable conditions after reaching 25%

\(^1\) A similar survey by American Municipal Power (AMP) of municipal utilities provides further confirmation that 4 hours may be insufficient for startup for ICI boilers. Attachments to comments filed by ACC, CIBO, and AMP provide examples of startup instructions and data from members affected by the Boiler MACT rule. The procedures in these documents are guidelines designed for individual units, and cannot be generalized for all boilers or control equipment. Exact procedures may vary depending on operating conditions and other circumstances, and guidelines may be updated from time to time.
load. On a hot startup, responses indicate that fluidized bed boilers can take up to 13 hours to reach stable conditions after reaching 25% load, pulverized coal boilers can still take up to 5 hours to reach stable conditions after reaching 25% load (especially for units that come online with a clean fuel and transition to solid fuel), and stoker and hybrid suspension grate type units can take up to 4 hours to reach stable conditions after reaching 25% load.

Circulating fluidized bed boilers need adequate time to establish stable bed conditions such as reaching the temperature and pressure necessary for stable operation and to calcine the limestone in the bed to begin achieving acid gas control within the bed. Although we only received 3 responses on bubbling fluidized bed units, it appears from that limited feedback that the time required for this design to achieve stable operation after 25% load is more similar to pulverized coal units. Liquid units can typically achieve stable operation within 4 hours of reaching 25% load.

In summary, the length of startup period for achieving safe and stable operations depends upon a number of source-specific factors. While we support using a standard period of time for east of administration, four hours after generating useful thermal energy does not reflect a typical startup period for many of the ICI boiler subcategories. The data indicate that a 26-hour period would ensure that all units can reach safe and stable operating conditions after generating useful thermal energy. We also recommend that EPA include an opportunity to define a different startup period with the permitting authority as part of the source-specific startup plan. CIBO also provided to EPA explanations of example startup scenarios, demonstrating the variation that is typical of the ICI boiler category and showing the need for source-specific treatment in many instances. See Attachment F (Startup and Shutdown Scenarios and Issues for Solid Fuel Boilers.)

EPA’s proposed use of a 4-hour startup period is based on sources that are not part of the ICI Source Category. EPA’s support is based on data for EGUs subject to the MATS rule (Subpart UUUUU):

Since the types of controls used on EGUs are similar to those used on industrial boilers and the start of electricity generation is similar to the start of supplying useful thermal energy, we believe that the controls on the best performing industrial boilers would also reach stable operation within 4 hours after the start
of supplying useful thermal energy and have included this timeframe in the proposed alternate definition.

80 FR 2875.

As a basis for the 4-hour period, EPA appears to have evaluated EGU CEMS data for NOx and SOx, not industrial boiler data for pollutants regulated under this rule, such as particulate matter (PM). Yet EGU data are not an appropriate basis for defining startup for ICI boilers, particularly when EPA has the ICI boiler data described above.

In addition, although this rule directly addresses the timing for engaging PM controls, EPA admits in its November 2014 technical support document “Assessment of startup period at coal-fired electric generating units – Revised” that EPA did not review any data for PM controls in establishing the startup definitions. EPA-HQ-OAR-2006-0790-2531 (relied on by EPA in this proposed rule at 80 FR 2875 at fn 1).

ICI boilers that will be most dependent on this alternate definition do not operate similarly to EGUs. The sole purpose of an EGU is to generate electricity on demand so they have every reason to startup as quickly as possible. By contrast, industrial boilers must start up in concert with the processes that use the energy they supply. For a complex facility with multiple process operations that need heat, steam, and electricity to operate and must start up in a certain sequence, the goal is not to start up the boilers as fast as possible. The goal is to match the operation of the boilers with the needs of the process and start up the entire facility in a safe and efficient manner without damaging equipment and to make quality product. Thus, the time until the start of electricity generation – the key factor in EPA’s startup analysis under MATS – is not a factor that is generally relevant in assessing an appropriate startup period for industrial boilers.

ICI boiler “best performers” are NOT those units that simply experience the shortest startup time, but rather those that demonstrate an optimum startup time providing proper equipment heat-up time to minimize/control equipment thermal stresses, adequate time for process heat-up and function to occur so that control systems can adequately function, adequate time for emissions control systems to heat up and stabilize without causing upset conditions, and other such requirements. The overall time for all of these functions to occur will vary by unit and
application. That time will also vary depending on the state of the unit when startup is initiated, e.g., cold start after the unit being shut down for an extended period of time versus hot restart or warm restart after the unit being shut down for only a short period of time.

Above all, the boiler operator’s primary concern during startup is safety, because startups are demonstrated to be the most hazardous operating period. The startup procedures must ensure that the equipment is brought up to normal operating conditions in a safe manner and as recommended by the equipment supplier. Startup ends when the boiler and its controls are fully functional and supplying steam to the processes and/or building requiring the energy. In many cases, stable operation of a boiler is tied to whether the process being served has reached stable operation, especially where a single combustion unit is supporting startup of a dedicated process. The procedures and the time necessary to complete a startup are site specific, and vary by boiler fuel, design, and control technique. The end of startup occurs when safe, stable boiler and process operating conditions are reached, and after emissions controls are properly operating. These factors support a longer startup period and a simple process for granting additional time where necessary to accommodate unique ICI boiler operating circumstances.

**It is well within EPA’s authority to provide for a longer startup period for industrial boilers.** In this rule, EPA uses the CAA §112(d)(3) methodology for setting floors for numeric standards, to define startup period. That methodology is inapplicable to definitions in a NESHAP and it would produce unsafe and unstable operating conditions.

The § 112(d)(3) methodology does not apply to the definition of a mode of operation. The § 112(d)(3) methodology requires EPA, when setting *numeric emission limits*, to calculate the average emission limit achieved by the best performing existing sources or the best controlled similar new source. On its face, the statutory provision governs only *numeric* standard setting, not defining core terms. In addition, floor setting is fundamentally quantitative. By contrast, defining the safe and stable end of startup for a category of boilers that serve diverse operational functions is qualitative not quantitative.
Under the authority of § 112(h), EPA considered in the Area Source final rule for ICI boilers whether “performance testing, and therefore, enforcement of numeric emission limits, would be practicable during periods of startup and shutdown.”

EPA determined that it is not technically feasible to complete stack testing—in particular, to repeat the multiple required test runs—during periods of startup and shutdown due to physical limitations and the short duration of startup and shutdown periods.

76 FR 15560 (Mar. 21, 2011). Thus, EPA did not calculate numeric standards for startup and shutdown based on the average emission limitation achieved by the best performing sources, as required by § 112(d)(3) for numeric standards. Instead, EPA developed narrative standards that define the work practices for minimizing emissions during startup and shutdown periods. EPA also did not develop numeric generally available control technology (GACT) standards for startup and shutdown, but instead set management practices for those periods of operation.

In the 2015 Area Source Proposed Reconsideration Rule, EPA has not repudiated its findings nor abandoned them as the basis for having decided to set work and management practice standards for startup and shutdown periods. EPA’s data set for ICI boiler emissions during startup and shutdown periods on reconsideration still lacks emissions data on which EPA reasonably can calculate the average emissions limitation achieved by best performers.

It is illogical for EPA to now turn to a different type of data—the amount of time units take to achieve full operating load—and use that averaging methodology to set limits on the number of hours in the startup period through the definition of startup.

EPA’s interpretation of the § 112(d)(3) methodology as applicable to defining startup defies congressional intent because that interpretation falsely constrains EPA’s ability to fashion achievable standards as Congress intended. This is especially true for a source category—such as ICI boilers—that is made up of very diverse units, and for regulating a mode of operation—such as startup—that has very diverse characteristics among units in the category. Congress did not intend for EPA to look only at the top performing 12% to determine a safe startup period. That could impose unsafe and unstable conditions on 88% of the source category. There is no reason, nor does EPA offer any reason, for EPA to constrain its discretion under § 112(h) to
consider the entire source category when determining what timeframe constitutes a safe and stable startup period.

EPA has ample authority to define and regulate startup period in a way that accounts for the wide range of source types in this category, and to require that sources maximize emission reductions during those periods. On its face and under any rational interpretation of § 112, Congress did not intend EPA to apply § 112(d)(3) methodologies to defining core terms.

2. **Shutdown Definition**

EPA proposes significant revisions to the definition of shutdown, which are for the most part responsive to concerns raised in comments and petitions for reconsideration. Commenters support these revisions generally, but seek additional revisions to clarify that “shutdown” can end before the point at which no fuel is combusted in the boiler by initiating startup.

For example, a unit may begin shutdown due to an unscheduled momentary power outage. Power outages occur routinely for a wide range of reasons and are beyond the control of the boiler operator. In such circumstances, when systems trip due to unexpected or unknown causes, the correct operational response may be to initiate a restart sequence to bring the boiler back online. This avoids a complete shutdown and returns the unit to operation more quickly. This partial shutdown is not adequately addressed in the proposed definition of “shutdown.” However, the restart is covered by the alternate definition of “startup,” which includes “the firing of fuel in a boiler for any purpose after a shutdown event.” Therefore, Commenters suggest that EPA add to the definition of “shutdown” that a shutdown can also end when “startup” begins.

3. **Useful Thermal Energy Definition**

EPA proposes to define “useful thermal energy” to mean “energy (i.e., steam, hot water, or process heat) that meets the minimum operating temperature and/or pressure required by any energy use system that uses energy provided by the affected boiler.” 80 FR 2884; 40 CFR § 63.11237 (proposed). Commenters support this definition.
B. ALTERNATIVE PM STANDARD

The February 1, 2013, final rule added a new provision that specifies that new or reconstructed oil-fired boilers with heat input capacity of 10 million Btu per hour (MMBtu/hr) or greater that combust only oil that contains no more than 0.50 weight percent sulfur or a mixture of 0.50 weight percent sulfur oil with other fuels not subject to a PM emission limit under this subpart and that do not use a post-combustion technology (except a wet scrubber) to reduce PM or sulfur dioxide emissions meet GACT for PM, providing the type of fuel combusted is monitored and recorded on a monthly basis. See 40 CFR § 63.11210(e). EPA’s rationale for this alternative is that sufficient testing has shown that ultra-low sulfur diesel (ULSD) contains low levels of urban metal HAP, thus assuring that this alternative standard is effective. 80 FR 2876-77.

Overall, EPA’s decision to set GACT emission limits instead of MACT is appropriate. EPA set numeric emission limits for new oil-fired units with heat input capacities 10 mmBtu/hr or greater because those units will already have to comply with the new source performance standard (NSPS) emission limits for PM, which requires PM testing. 76 FR 80537. EPA’s decision to set numeric GACT emission limits for larger new units that will already have to comply with NSPS is appropriate. This approach is justified as EPA has as recently as 2009 reviewed and promulgated standards for the small industrial boiler NSPS and determined that a PM limit of 0.030 lb/MMBtu is appropriate for new small boilers. See 74 FR 5091.

The NSPS provides an exemption from the PM limit for units burning low-sulfur fuel at § 60.43c (e)(4):

“an owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.50 weight percent sulfur or a mixture of 0.50 weight percent sulfur oil with other fuels not subject to a PM standard under §60.43c and not using a post-combustion technology (except a wet scrubber) to reduce PM or SO2emissions is not subject to the PM limit in this section.”

Thus, it is appropriate for EPA to revise the 2013 Area Source Final Reconsideration Rule to include an alternate compliance approach of using low-sulfur fuel. This keeps the Area Source rule consistent with NSPS, with which the same units also have to comply.
EPA also seeks comment on whether the definition of low-sulfur would allow emissions that exceed the PM limit. The attached graphs of boilers at major and area sources show PM emissions data for uncontrolled #6 oil boilers vs uncontrolled #2 oil boilers from EPA’s boiler database. The vast majority of the PM emissions from the uncontrolled #2 oil boilers (these would be <0.5% sulfur) are well below the area source PM limit of 0.03 for new liquid units. Some of the data above the limit may not be properly marked as #2 oil emissions. See Attachment G, PM Emissions Uncontrolled No. 6 Oil vs. No. 2 Oil.xlsx. Heavy liquid units will still be subject to ongoing monitoring and/or testing because combustion of these fuels without emissions controls typically results in emissions greater than 0.03 lb/MMBtu. PM emissions from the low sulfur liquid fuels - like #2 oil, biodiesel - from EPA boiler database are typically below the area source limit of 0.03 lb/MMBtu. See Attachment H, PM Emissions Low Sulfur liquid fuel.xlsx.

C. LIMITED-USE BOILER SUBCATEGORY AND STANDARDS

The final Area Source Rule established a limited-use boiler subcategory (similar to the provision in the Boiler MACT rule) for solid or liquid-fired boilers that have a federally enforceable average annual capacity factor of 10% or less. The 2015 Area Source Proposed Reconsideration rule provides the following definition, retained from the 2013 Area Source Final Reconsideration Rule with one change: “Limited-use boiler means any boiler that burns any amount of solid or liquid fuels and has a federally enforceable annual capacity factor of no more than 10 percent.” 80 FR 2883; 40 CFR § 63.11237 (proposed). EPA’s only proposed change to this definition is to the capacity factor, which is now an “annual capacity factor” instead of an “average annual capacity factor.”

EPA seeks comment on whether this subcategory is appropriate and necessary and detailed information supporting the comment. Commenters support retaining this subcategory as defined as proposed. Limited use units have a rated heat input greater than 10 MMBtu/hr with an annual average capacity factor of 10% or less. This is the best means of defining a limited-use boiler. EPA came to that conclusion in the 2013 major source boiler rule, which includes a subcategory for limited-use units that is based on an annual average capacity factor of 10% or less. See 40 CFR § 63.7499(o); 40 CFR § 63.7575.
A subcategory for limited-use units is important due to these units’ significant differences from steady-state units. Many of these units operate for short periods of time during the year and therefore spend a larger proportion of their time in startup and shutdown. They also may experience relatively few startup, shutdown or malfunction events. Because limited use units do not operate regularly, their emissions differ from other boilers operating continuously or operating near their design capacity. EPA has recognized that "units operate most efficiently when operated at or near their design capacity." 75 FR 32023-24. Based on their operating schedule, limited-use units do not operate at or near their design capacity.

Additionally, the short operating times of limited use units result in difficulties in effectively controlling emissions. As EPA has noted, based on the operating schedules of limited use units, EPA could not identify a control technology for controlling organic HAP emissions. See EPA, Response to Public Comments on Proposed Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP, at 67 (Feb. 25, 2004). Because these Area source limited use boilers are similar in all relevant respects to major source limited use boilers and for consistency, EPA is justified in establishing this subcategory as defined in the 2015 Area Source Proposed Reconsideration Rule.

Furthermore, because of the short operating times and difficulty in controlling emissions of these boilers, EPA should retain the work or management practice standard for the limited use subcategory. EPA has acknowledged that there is no proven control technology for organic HAP emissions from limited-use units. Second, limited use units, such as emergency and backup boilers, cannot be tested effectively due to their limited operating schedules. This is due to the fact that there is often no time to conduct performance tests on a unit operating in a limited capacity. Based on existing test methods, limited use units would have to operate for the sole purpose of being subjected to emissions testing. Such a result is counter to the general intent behind the CAA. EPA should therefore use its authority under § 112(h) and adopt a work practices standard for limited use units and not subject the subcategory to emissions monitoring.

D. FREQUENCY OF TESTING FOR PM COMPLIANCE

The rule proposes a provision that eliminates further performance testing for particulate matter for boilers whose initial compliance test shows that its particulate matter emissions are equal to
or less than half of the particulate matter emission limit. Commenters support this provision as qualified below.

The proposed provision is reasonable and in line with other MACT and NSPS standards. Many MACT standards and NSPS standards require only one initial performance test unless there is a physical change to the control device. This proposed revision also reduces the burden on sources that still existed under the triennial testing requirement in the 2013 Area Source Final Reconsideration Rule. CIBO 2012 Comments on Proposed Recon Area Source Rule at 10, EPA-HQ-OAR-2006-0790-2443.

EPA acknowledges that the cost of testing small boilers is prohibitive, and EPA is right to consider these costs when establishing the frequency of testing. If a unit continues to comply with all applicable operating limits and monitoring requirements, then the benefits of requiring subsequent testing do not justify the costs. HAP emissions change only when operating parameters change (e.g., firing rate, maximum contaminant input limits for chloride and mercury, type of fuel, combustion efficiency, oxygen content, etc.) or when design changes occur. Absent these changes to an affected source, operating parameters established by implementation of the Area Source Rule are more than sufficient to ensure that emissions of these inherently low-emitting sources will not significantly change over time. *Id.* We agree that inclusion of this provision promotes good PM performance from new boilers and acknowledges that some boilers are inherently low-emitting and should be spared the burden of ongoing performance testing where operations remain consistent.

**E. Hg ALTERNATE COMPLIANCE**

In the 2013 Area Source Final Reconsideration Rule, EPA specified that units do not need to conduct further fuel analysis sampling if, when demonstrating initial compliance with the Hg emission limit, the Hg constituents in the fuel or fuel mixture are measured to be equal to or less than half of the Hg emission limit. In contrast, if the initial compliance demonstration shows that Hg constituents in the fuel or fuel mixture are greater than half of the Hg emission limit, then the owner must conduct quarterly sampling.

Commenters support this provision. For units complying with the mercury standard, requiring fuel analysis any more frequently would be unjustifiably burdensome. As much of the data in
the Boiler MACT survey database demonstrate, coal mercury content is below the Hg emission limit established by the 2013 Area Source Final Reconsideration Rule. Subsequent fuel analysis will not provide additional useful information, is unnecessary and the costs are unwarranted.

F. AFFIRMATIVE DEFENSE

Invoking the DC Circuit decision NRDC v. EPA, 749 F.3d 1055 (D.C. Cir. 2014), in which the court invalidated the affirmative defense in the Portland Cement MACT rule, EPA proposes to remove the affirmative defense in the rule. This proposal is contrary to law and not a rational response to the DC Circuit decision in NRDC.

Commenters oppose removing the affirmative defense, where the final rule otherwise provides sources no means of demonstrating compliance during malfunction periods. As the rule now stands, sources experiencing malfunctions must meet numeric limits that were developed based on emissions during normal operating periods. The Clean Air Act (CAA) requires EPA to establish technology-based standards that properly account for malfunction periods and that apply during malfunction periods. EPA’s failure to establish achievable standards in the final area source boiler rule that apply during malfunction events is contrary to the CAA and arbitrary and capricious. EPA should find that setting numeric standards is not feasible or practicable and on that basis set work practice standards. This issue is pending before the DC Circuit Court in US Sugar Corp. v. EPA (No. 11-1108), ACC v. EPA (No. 11-1141) and AF&PA v. EPA (No. 11-1125). Until that issue is resolved by the DC Circuit Court, EPA should not remove the affirmative defense.

NRDC does not compel EPA’s proposed action here to remove the affirmative defense in this rule. The DC Circuit in that case invalidated the affirmative defense in the context of the Portland Cement MACT rule because, “[b]y its terms, Section 304(a) clearly vests authority over private suits in the courts, not EPA. As the language of the statute makes clear, the courts determine, on a case-by-case basis, whether civil penalties are “appropriate.” NRDC v. EPA 749 F.3d at 1063. The NRDC Court decided the issue before it – whether EPA has authority to establish the affirmative defense -- without addressing the implications of its decision on the

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2 These data are equally applicable to the Area Source Rule—there is no distinction between the coal burned by area source boilers and that burned by major sources.
emission standards in that rule. EPA cannot simply directly apply the NRDC ruling to the Area Source rule without addressing its implications on the emission limits in the rule, which were set without including malfunction emissions.

Without the benefit of the affirmative defense, because sources are indisputably incapable of complying during malfunctions with the numeric emission limits in the rule, sources would be totally dependent on enforcement discretion for compliance with the rules during malfunction periods. This is illegal. The DC Circuit has made clear that such an approach improperly shifts the question of what is technologically achievable “to the enforcement stage, an approach not contemplated” by the Clean Air Act. Portland Cement Ass’n v. Ruckelshaus, 486 F.2d 375, 398 n.91 (D.C. Cir. 1973).

EPA does not even propose anything to attempt to rectify the situation, such as, for example, the interim relief of non-enforcement discretion. EPA does not propose to suspend the effect of the emission limits as applied to malfunction periods, pending a judicial outcome of the underlying dispute. EPA also does not explain why the numeric standards remain legal in the absence of the affirmative defense, where the inclusion of that defense was central to EPA’s conclusion that technology-based standards need not reflect malfunction periods.

EPA’s proposal to remove the malfunction provision, including its faulty claim of legal authority and absence of any discussion on which sources could provide meaningful comment, should not be finalized. Instead, EPA should announce that it is exercising administrative enforcement discretion for malfunctions to address the immediate concerns of regulated sources and await the outcome of the multiple related substantive matters now pending in the courts.

G. TECHNICAL CORRECTIONS & CLARIFICATIONS

1. Energy Assessment

The rule proposes that sources can satisfy the energy assessment requirement if they have “operated under an energy management program developed according to the ENERGY STAR guidelines for energy management or compatible with ISO 50001 for at least one year between
January 1, 2008, and the compliance date specified in §63.11196 that includes the affected units. . .” Table 2 to 40 CFR 63 Subpart JJJJJJJ (new proposed text in italics).

Commenters support this alternative compliance with the EA requirement. It reflects the similarity in goals of the EA requirement and those achieved by energy assessments that sources may already have undertaken at their sites.

2. Oxygen Set Point for Sources Not Required to Conduct a CO Performance Test

In the 2013 Area Source Final Reconsideration Rule, 40 CFR § 63.11224(a)(7) describes the requirement for oxygen trim systems for boilers subject to a CO emission limit in Table 1. Paragraph (a)(7) requires the oxygen level of the system to be set “no lower than the lowest hourly average oxygen concentration measured during the most recent CO performance test as the operating limit for oxygen.” 40 CFR § 63.11224(a)(7). However, paragraph (a)(7) does not address the oxygen set point for a source that is not required to conduct a CO performance test. Therefore, EPA has proposed to amend § 63.11224(a)(7) by adding the italicized text as follows:

(7) You must operate the oxygen analyzer system at or above the minimum oxygen level that is established as the operating limit according to Table 6 to this subpart when firing the fuel or fuel mixture utilized during the most recent CO performance stack test. If your facility is not required to conduct a CO performance stack test, you must set the oxygen level to the oxygen concentration measured during the most recent tune-up to optimize CO to manufacturer’s specifications and you must operate the oxygen analyzer system at or above that level. Operation of oxygen trim systems to meet these requirements shall not be done in a manner which compromises furnace safety.

While we agree with EPA that this provision should be amended. However, to make this amended provision workable, EPA’s proposed textual change should be amended as shown here in italics:

(7) You must operate the oxygen analyzer system at or above the minimum oxygen level that is established as the operating limit according to Table 6 to this subpart when firing the fuel or fuel mixture utilized during the most recent CO performance stack test. If the facility is not required to conduct a performance stack test, you must set the oxygen level no lower than the average measured during the tune-up final setup testing to optimize CO to manufacturer’s specifications. Operation of oxygen trim systems to meet these requirements shall not be done in a manner which compromises furnace safety.
This amended version is more accurate and therefore will be more likely to achieve the goal of the provision.

3. **Changes to Definition of Coal**

EPA proposes to revise the definition of “Coal” to clarify that coal-derived liquids are considered to be a liquid fuel type. Commenters oppose this change.

Commenters oppose the substance of the proposed change to the coal definition. The revised definition is not logically consistent with the other fuel definitions and irrationally recategorizes specific units as liquid fuel fired where a data analysis would rationally lead to them remaining in the solid fuel category.

A substantive discussion would demonstrate that they are logically within the coal-fired category. Per EPA’s proposed revised definition, coal includes coal-oil mixtures and coal-water mixtures within the definition, but specifically excludes coal-derived liquids. The following link explains coal-water mixtures and their use as gas and oil replacement:

http://en.wikipedia.org/wiki/Coal-water_slurry_fuel. Coal-oil mixtures would be similarly used, but have higher heating value. Therefore, coal-water mixtures and coal-oil mixtures are both included and both utilized as liquid oil or gas replacement fuels, similar to utilization of coal-derived liquids. It is illogical to treat coal derived liquids differently than these two coal based mixtures, and all should be regulated like coal.

Commenters also oppose the proposed change on procedural grounds. EPA makes clear that the proposal is limited to specific issues for which reconsideration was granted (this issue is not among them) and that EPA “will not respond to any comments addressing any other issues or any other provisions of the final rule.” 80 FR 2871. In addition to those specific topics, EPA also proposed technical amendments to many provisions. EPA categorizes the definition of coal as a technical amendment. That is not correct. This topic is clearly beyond the narrow scope of a technical amendment and triggers EPA’s obligation under the CAA and Administrative Procedure Act (APA) to “give interested persons an opportunity to participate in the rule making through submission of written data, views, or arguments” 5 U.S.C. § 553.

EPA has not fulfilled its obligations for rule proposals under Section 307 of the CAA. EPA has not included, with respect to this proposed provision, a statement of basis and purpose that
provides “(A) the factual data on which the proposed rule is based; (B) the methodology used in obtaining the data and in analyzing the data; and (C) the major legal interpretation and policy considerations underlying the proposed rule.”  CAA § 307(d)(3).  Having bypassed all procedural requirements by framing this as a technical amendment, EPA has not engaged in legal, rational decision-making on whether to revise the definition of coal to exclude coal derived gases and liquids.

As the short substantive discussion of the issue above makes clear, this proposal constitutes a rule under the APA.  5 U.S.C. § 551(4)(it is “designed to implement, interpret, or prescribe law or policy …”).  The DC Circuit Court would clearly consider this proposed revision a substantive rule under its well established four-part test:  (1) “whether in the absence of the rule there would not be an adequate legislative basis for enforcement action; (2) did the agency publish it in the Code of Federal Regulations; (3) did the rule amend or repudiate a prior rule; and (4) whether the agency invoked its legislative authority.  Am. Min. Congress v. Mine Safety & Health Admin, 995 F.2d 1106, 1112 (D.C. Cir. 1993).  Measured against this test, the proposal is a rule:  (1) EPA would be able to take enforcement action against the excluded units; (2) the provisions of the boiler reconsideration rule will be published in the Code of Federal Regulations (CFR); (3) the rule changed the current definition of coal in the CFR ; and (4) EPA invoked its legislative authority when proposing the reconsidered rule.

For all these reasons, procedural and substantive, EPA should not finalize this proposed change to the rule.

4.  Definition of Load Fraction

EPA proposes to revise the definition of load fraction in the 2015 Area Source Proposed Reconsideration rule by adding the italicized text to the current version of the rule (found at 40 CFR § 63.11237).

Load fraction means the actual heat input of a boiler divided by heat input during the performance test that established the minimum sorbent injection rate or minimum activated carbon injection rate, expressed as a fraction (e.g., for 50 percent load the load fraction is 0.5).  For boilers that co-fire natural gas with a solid or liquid fuel, the load fraction is determined by the actual heat input of the solid or liquid fuel divided by heat input of the solid or liquid fuel fired during the performance test (e.g., if the performance test was conducted at 100 percent solid
fuel firing, for 100 percent load firing 50 percent solid fuel and 50 percent natural gas, the load fraction is 0.5). 80 FR 2883.

Commenters support this revision because it recognizes that neither a boiler’s Hg, SO2, or HCl emissions are affected by the portion of the boiler’s heat input attributable to firing natural gas.
<table>
<thead>
<tr>
<th>Boiler Type</th>
<th>Primary Fuel</th>
<th>Control</th>
<th>Responses Received (# units)</th>
<th>Cold Startup Data</th>
<th>Warm Start Data</th>
<th>Hot Start Data</th>
<th>Total time to reach stable operation</th>
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<tbody>
<tr>
<td>Circulating FBC</td>
<td>Coal or coal/biomass</td>
<td>Baghouse</td>
<td>20</td>
<td>4.5-31 0.1-4 1-26 6.5-45 4.4-18 0.1-4 2.1-24 6.6-34 0.6-4 0.4-4 1.1-13</td>
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<td>Bubbling FBC</td>
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<td>6 1 1 8 4 1 1 6 2-4 1 1 4-6</td>
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<td>1-8 0.025-5 0.5-8 2.2-15 1-6 0.039-6 0.5-6 2.4-17 0.5-5 0.017-5 0.5-4 2.8-15</td>
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<tr>
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<tr>
<td>Liquid</td>
<td>Liquid</td>
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<td>4</td>
<td>5.5-8 1.2 1.2 7.5-11 5.5-8 1.2 1.2 7.5-11 4.5-7 0.5-2 1-2 6.5-11</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
OPERATION

-CAUTION-

1.0 Filter Bag and Housing Damage - can occur if proper combustion control is not maintained.

2.0 Fire/Explosion Hazard

Many dusts represent an explosion and/or fire hazard. The potential of either is determined by the type of dust(s) encountered, their concentration, methods of dust storage, and the potential for an ignition source to be present. DUSTEX makes available explosion vents and some types of fire suppression systems. If you have not addressed the need for such equipment, advise your DUSTEX representative or the DUSTEX home office prior to start-up. It is further recommended that you contact your insurance underwriter for their input as to protective auxiliary equipment.

Determination of the need for and the supply of auxiliary equipment for the venting of explosions or the sensing and suppression of fire are the total responsibility of the owner. DUSTEX does not accept liability for the direct or indirect effects of fire or explosion in its dust control equipment.

3.0 Acids Can Condense - on cold filter and inside wall surfaces if surfaces are under the dew point. During start-up and shut-down, precautions must be taken so that cold surfaces are not exposed to hot acid-laden gasses.

At start-up the system must be preheated with non-acid bearing fuel so that all surfaces reach at least 300°F before the process begins or bypass damper is closed.

At shut-down, combustion gasses must be immediately purged with hot dry air before the fan(s) are shut down. If the system goes on by-pass, control provisions should be established to allow the ID fan to purge the baghouse with ambient air.

Baghouse Hoppers Are Not Intended For Dust Storage - ash and dust can contain materials which continue to oxidize and release heat. If any carbon material is present, a fire hazard as a result of spontaneous combustion can occur.

Ash remaining in the hopper can be re-entrained on the filter bags causing undo wear and an elevation of pressure differential.

Continuous removal of collected ash and dust is recommended.

With regard to baghouse operation, anticipated sequences of start-up and shut-down are as follows: (Note: system instrumentation and control logic by others.)

5.0 Pressure Drop Across Collector - occasionally during operation it is desirable to manually check the pressure drop across the collector.
Recommended Rate of Warming Up or Cooling Down

See Operating Instructions

Section 5, Page 2
B & W BOILER

OPERATING PROCEDURE

A) COLD START (Before starting fans, be sure to have oil in the bearings)

1. Start I D Fan
2. Start F D Fan
2a. Start Scanner Cooling Air Blower
3. Start Air Heater
4. Start Cooling Water to I D Fan, Air Heater, Ash Hopper Doors.
4a. Start Air flow to scanners.
5. Check for proper water level in ash hopper seal trough.
6. Check for proper oil level in I D Fan bearings, F D Fan bearings and air heater.
7. Open I D & F D Fan dampers to 30% air flow as indicated on the air flow chart, keeping furnace pressure at - 0.2 inches.
8. Open all air registers.
9. Place all Impellers at the retracted position.
10. Press start purge pushbutton - Boiler will purge for 5 minutes.
11. Open Non-Return valve to full open position.
12. Open superheater drains.
13. When purge complete light comes on, close air register of the burner being lit, open gas header valve.
14. Light burner ignitor by pressing the ignitor start pushbutton.
15. When ignitor proves lit, open air register to the light-off position.
16. Light second ignitor (start at step 13 through step 15).
17. Bring Boiler up to pressure (Minimum required time is 6 hours).
18. Superheater Thermocouples should be monitored. When superheater metal temps. reach approx. 585°F, superheater is boiled out and unit may be placed on line, superheater drains should be closed.
19. Watch water level at all times no more than two igniters are required to bring the unit up to pressure.
20. Refer to separate instructions for oil or coal firing.

B) HOT START

1. Follow steps 1 through 10 above.
2. Place all 4 igniters in service.
3. Refer to separate instructions for oil or coal firing.
4. Boiler should Not increase more than approximately 200 psi per hour. Igniters will produce approximately 10,000 lbs/Hr. of steam each.
PRESSURE RAISING SCHEDULE

There are many factors to be considered in warming up a unit. In general follow the curve of suggested warm up rate, Section 5. It would be possible to bring a cold unit up to operating pressure in much shorter time but this is undesirable because the unit would be subjected to severe strains and stresses. It is generally considered good practice to warm a unit up at a rate that will cause 100°F saturated temperature rise per hr. This rate will assure even temperature distribution throughout the unit and usually permit steam temperature to be held to the desired point.

Approximately one and one half hours is allowed for bringing the unit from room temperature to boiling temperature at atmospheric pressure 212°F. If the unit is filled with hot water, this time will be reduced, but should not be less than forty-five minutes. This will assure time for the setting to absorb some of the heat. Steam will then be emerging from the drum vent. The pressure increases should closely follow the curve. Firing should be kept as steady as possible but intermittent firing may be necessary in some cases. Intermittent firing should be carried out as follows:

1. Fire at the lowest possible rate until an increase of 100 psig is obtained. If this takes less than 40 minutes, it should be done by separate firings with time out between firings to meet the curve requirement.

2. Fans should be left running during the non-firing periods to let heat disperse through the unit. The forced draft dampers may be left in position and the air reduced by closing the burner dampers. The furnace draft should be the normal - 0.1". The oil ignition torch may in the large units be left burning as it provides relatively little heat.

The pressure raising schedule should also take into account the superheated steam temperature rise. The steam temperature should not be allowed to rise to more than 100°F. above the superheated and reheated steam temperature expected in normal operation and its rise should be moderate. If the temperature of the gases entering the superheater and reheater section is kept below 1000°F., there will be no trouble. (See Section 5SP)

When boiler pressure approaches line pressure, see section on "Placing Unit on Line".
START UP CURVES

CURVE I - BOILERS WITHOUT SUPERHEATERS
120°F PER HOUR TEMP INCREASE ≤ 100°F INITIAL BOILER WATER TEMP

CURVE IA - BOILERS WITH SUPERHEATER
100°F PER HOUR TEMP INCREASE ≤ 100°F INITIAL BOILER WATER TEMP.
1. Before starting, be sure to that 8 radios are available and distributed to each Fireman and each Boiler worker. Management keeps them off the floor, in their office. You have to ask for them every start up.
2. Perform Boiler walk down as described in “Pre Start-Up Walk Down” procedure.
3. Check boiler water level. Blowdown or fill boiler until it is at two or three green glasses in sight glass. Drum level control should be at zero or less.
4. Open and adjust Stoker Cooling Water. Start rotors and set speed at 20 Hz.
5. Insert temperature probe in the side of the firebox on the coal scale floor and set the dial located in the back of control cabinet at “2.” Confirm read out is working on the panel.
6. Start ID Fan and place in AUTO
7. Start Coal FD Fan and keep in manual
8. Start Gas Burner FD Fan and keep in manual
9. With Coal ID damper already in AUTO,
   a. Set Coal FD damper at 30%, Coal FD Speed at 37%, (must have 40,000 flow air flow min.) Natural Gas Master at 0% in manual, Gas burner A & B damper both in AUTO. Set Gas FD in 10% in manual.
   b. At the gas burner panel, set gas burner purge selector switch to “Cold”
   c. Hit the PF key on the Gas Burner FD Damper. Gas FD damper should open 100% at this time. (Gas Master must be at “0” to do this)
   d. Once dampers are 100% open, purge will start timing out.
   e. When 5 seconds are left in purge cycle, hit the PF key key on the damper control. Damper will ramp back down to 10 and burners should light OFF.
   f. After Burners are lit – Set Gas Master at 5%, Gas FD at 10%, Coal Damper at 30%, and Coal FD speed at 37%.
   g. Leave burner at 5% for one hour for warm-up.
10. Raise Gas in 5% increments. Once steam is visible coming out of the vents, start backing down the FD damper to start raising the furnace temperature.
11. Close super heater vents.
12. Close drum vent when boiler reaches 20 to 50 psi.
13. Set 400 psi control valve at 5% to warm up the header.
14. Start checking super heater temps when firebox reaches 600 degrees. Each tube must show a jump of 100 degrees in one hour to be considered clear.
15. Whenever boiler pressure reaches 200#, notify operating engineer so they can start warming up header.
16. If pressure stops rising, pinch back on super heater drains until pressure reaches 450 psi.
17. Check 400# header that is rising.
18. Continue lowering the FD damper when gas is at 40%.
19. Raise 400# valve to 10%.
20. Once 400# header reaches 240#, adjust 400# control set point at 240 and put in AUTO.
21. Set 2# steam valve control at 10% if it is less than the 1.8 set point.
22. Start Over Fire Air Fan – Set Control at ?
23. Wait for notification from the Operating Engineer that they have started rolling the turbine which will give approximately a 45 minute window for when they will need the boiler on line burning coal. When they call, start adding coal to the boiler and proceed with light up. Always leave the rotors running and adjust fuel bed by switching feeders on and off as needed.

24. When the call comes that are putting the turbine on line, close the superheater drains, switch all stoker feeders to auto and adjust coal feeding as required to maintain pressure.

25. Send the helper to open the feedwater knocker valve all the way and open the feedwater pump effluent valve all the way.

26. Start backing down the gas burners in 5% intervals.

27. Start bumping up the 400# line set point until it is at 340# and put in AUTO.
Startup and Shutdown Scenarios and Issues for Solid Fuel Boilers

<table>
<thead>
<tr>
<th>Controls</th>
<th>Scenario</th>
<th>Potential Compliance Issue</th>
<th>Suggested Solution</th>
</tr>
</thead>
<tbody>
<tr>
<td>Any</td>
<td>Startup on clean fuel, engage non-listed controls prior to adding solid fuel.</td>
<td>May be an issue with clean fuel availability. May have CO issue with transition from gas or liquid fuel to solid fuel, may not be an issue for 30-day average depending on compliance margin.</td>
<td>Expand list of clean fuels to include all Other Gas 1 fuels, biodiesel, fuels that meet the HCl, Hg, TSM limits through fuel analysis, and other clean fuels as determined by permitting authorities. Provide adequate length of time for startup period to cover transition from startup fuel to solid fuel. (as defined below)</td>
</tr>
<tr>
<td>Wet</td>
<td>Startup on solid fuel</td>
<td>Shouldn’t be an issue for operating parameter monitoring – can start wet controls prior to startup (depending on design of wet controls, may not be able to meet operating parameter limits instantaneously, but should be able to meet 30-day average). Need to address units that share a common control device that startup separately. Could have issues meeting 30-day rolling CO CEMS limit if enough time is not given for startup. Need to differentiate between cold startup (need more time) and hot restart (need less time).</td>
<td>Startup ends either when the boiler or process heater has continuously maintained a steam production rate of at least 25% of maximum steam or heat output at normal operating pressure for a certain number of continuous hours after a cold startup or a certain number of continuous hours hour after a hot restart and when all control devices are in stable operation or when the boiler or process heater is operating above an alternate minimum operationally stable output flow rate and pressure for a minimum time, as specified in a site-specific start-up plan. This would also apply to units sharing a common control device that start up at separate times (separate startup period occurs for each unit). For units sharing a common control device that are starting up sequentially, startup ends either when the last boiler or process heater to start has continuously maintained a steam production rate of at least 25% of maximum steam or heat output at normal operating pressure for a certain number of continuous hours after a cold startup or a certain number of continuous hours after a hot restart and when all control devices are in stable operation or when the last boiler or process heater is operating above an alternate minimum operationally stable output flow rate and pressure for a minimum time, as specified in a site-specific start-up plan.</td>
</tr>
<tr>
<td>Controls</td>
<td>Scenario</td>
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<td>Suggested Solution</td>
</tr>
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<td>----------</td>
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<td>-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Dry</td>
<td>Startup on solid fuel</td>
<td>Can’t startup ESP until certain flue gas temperature and oxygen level are reached. NFPA 85- Boiler and Combustion Systems Hazards Code, 2011 Edition, Section 6 Multiple Burner Boilers (firing oil, gas, or PC) requires purging of precipitators prior to initial firing to prevent a precipitator spark from igniting an explosive mixture of unburned fuel. Manufacturing and operating company procedures may include a requirement to be operating on main burners with adequate flue gas temperature and low enough oxygen levels prior to ESP energization to limit potential ignition of unburned fuel by a precipitator spark. Need time within the “startup” period for the combustion unit firing primary fuel(s) and all exempted air pollution controls to reach stable operating conditions relative to the start of steam or process heater output to the distribution system. Need to get better definition of end of startup if heat or steam is immediately supplied upon ignition of fuel. Need to address units that share a common control device that start up separately. Could have issues meeting 24-hour block opacity or 30-day rolling CEMS limit if enough time is not given for startup. Need to differentiate between cold restart (need more time) and hot restart (need less time)</td>
<td>ESPs must be included in the Table 3, item 5 list of exempted air pollution controls that must be started as expeditiously as possible. Startup ends either when the boiler or process heater has continuously maintained a steam production rate of at least 25% of maximum steam or heat output at normal operating pressure for a certain number of continuous hours after a cold restart or a certain number of continuous hours after a hot restart and when all control devices are in stable operation or when the boiler or process heater is operating above a minimum operationally stable output flow rate and pressure for a minimum time, as specified in a site-specific start-up plan. This would also apply to units sharing a common control device that start up at separate times (separate startup period occurs for each unit). For units sharing a common control device that are starting up sequentially, startup ends either when the last boiler or process heater to start has continuously maintained a steam production rate of at least 25% of maximum steam or heat output at normal operating pressure for a certain number of continuous hours after a cold startup or a certain number of continuous hours after a hot restart and when all control devices are in stable operation or when the last boiler or process heater is operating above an alternate minimum operationally stable output flow rate and pressure for a minimum time, as specified in a site-specific start-up plan.</td>
</tr>
<tr>
<td>Controls</td>
<td>Scenario</td>
<td>Potential Compliance Issue</td>
<td>Suggested Solution</td>
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<tr>
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</tr>
<tr>
<td>Any</td>
<td>Unit begins startup, reaches a certain minimum stable load, then there is an equipment problem that results in “failed startup.”</td>
<td>All of the above.</td>
<td>Need to be sure that this entire period is considered startup, even if you reach the minimum load threshold. If, for example, the end of startup is 25% load plus 8 hours, the unit has to be over 25% for 8 continuous hours.</td>
</tr>
<tr>
<td>Wet</td>
<td>Lose solid fuel feed, takes time to get auxiliary fuel going to boiler or there is no auxiliary fuel available. Sometimes wet fuel can cause high O2 conditions, which will trip the ESP, which will trip the fuel feed. Sometimes there are problems with the equipment used to supply the solid fuel that cause loss of fuel feed.</td>
<td>Losing fuel feed would trigger a shutdown – however, shutdown as EPA currently interprets would not be completed if the unit continues supplying useful steam until fuel feed is restored. We can’t classify these periods as malfunctions in all cases and these periods are not normal operation. We need to be able to call them shutdown, or we don’t have certainty on how to classify these periods. Operating parameters would probably be okay on a 30-day rolling average basis. Whether or not there was an issue meeting 30-day rolling CO CEMS limit if this is not shutdown would depend on compliance margin and length of event.</td>
<td>The shutdown definition should accommodate the scenario where fuel feed is reinitiated before the unit ceases to supply steam. Facilities need to be able to call it a shutdown, even if fuel supply is restored. Facilities should not be forced to take the boiler down fully before reinitiating a startup – this would be uneconomical and could result in more emissions. The end of this period is a hot restart, and then the startup work practices would apply until certain load and time conditions are met. Could revise end of shutdown definition: “Shutdown ends when there is both no steam or heat being supplied and no fuel being combusted in the boiler or process heater or when startup is initiated by reintroducing fuel to the boiler or process heater after fuel feed has been halted.”</td>
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<td>Controls</td>
<td>Scenario</td>
<td>Potential Compliance Issue</td>
<td>Suggested Solution</td>
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<tr>
<td>Dry</td>
<td>Lose solid fuel feed, takes time to get auxiliary fuel going to boiler or there is no auxiliary fuel available. Sometimes wet fuel can cause high O2 conditions, which will trip the ESP, which will trip the fuel feed. Sometimes there are problems with the equipment used to supply the solid fuel that cause loss of fuel feed.</td>
<td>Losing fuel feed would trigger a shutdown – however, shutdown as EPA currently interprets would not be completed if the unit continues supplying useful steam until fuel feed is restored. Also, NFPA 85 Boiler and Combustion Systems Hazards Code, 2011 Edition, Section 6 Multiple Burner Boilers (firing oil, gas, or PC) requires tripping of electrostatic precipitators as part of a master fuel trip (MFT) to prevent a precipitator spark from igniting an explosive mixture of unburned fuel. We can’t classify these periods as malfunctions in all cases and these periods are not normal operation. We need to be able to call them shutdown, or we don’t know how to set up recordkeeping because we don’t have certainty on how to classify these periods. Could have issues meeting <strong>24-hour block opacity</strong> or 30-day rolling <strong>CO CEMS limit</strong> if this is not shutdown, depending on compliance margin, type of unit, length of event.</td>
<td>Need to be able to call it a shutdown, even if we get fuel back; emissions will be greater if we have to complete a shutdown before we can start back up. The end of this period is a hot restart, and then the startup work practices would apply until certain load and time conditions are met. Could revise end of shutdown definition: “Shutdown ends when there is <strong>both</strong> no steam or heat being supplied and no fuel being combusted in the boiler or process heater or when startup is initiated by reintroducing fuel to the boiler or process heater after fuel feed has been halted.” ESPs must be included in the Table 3, item 6 list of exempted air pollution controls that are not required to be operated during shutdown.</td>
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<td>Any</td>
<td>Begin shutdown upon halting fuel feed to the boiler. For some designs, there is still fuel burning in the boiler.</td>
<td>Current definition says “<strong>Shutdown begins either when none of the steam and heat from the boiler or process heater is supplied for heating and/or producing electricity, or for any other purpose, or at the point of no fuel being fired in the boiler or process heater, whichever is earlier.</strong>” This could be interpreted that shutdown does not begin unless no fuel is burning or no steam/heat is being supplied. In some boiler designs, fuel continues to burn after fuel feed stops.</td>
<td>EPA should clarify that fuel being fired in this case means fuel being fed to the combustion unit.</td>
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<td>Controls</td>
<td>Scenario</td>
<td>Potential Compliance Issue</td>
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<tr>
<td>Wet</td>
<td>More than one unit vents to a wet control device, one unit shuts down, the other unit stays operating.</td>
<td>For some wet control designs, the pressure drop depends on the flow through the scrubber. If only one unit is operating, the operating parameter limits established during the performance test with both units in operation may not be achievable.</td>
<td>Not sure if there is a way to address this in the rule, or if EPA would advise facilities to submit a request for alternate monitoring and establish different operating scenarios, such as an alternate operating limit with fewer units in operation. This is similar to the question of whether operating parameters must be maintained if a unit burns gas for an extended period of time and emissions controls for PM, HCl, Hg are not needed. This is probably covered under a request to permit alternate operating scenarios as well.</td>
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<td>Any – low load/standby unit</td>
<td>A unit operates for many hours in standby mode, less than 25% load.</td>
<td>How to define the end of startup to accommodate a unit that operates in a low-load mode after initial “ignition” (e.g., it never reaches 25% load).</td>
<td>Where a 25% load+time threshold can’t be accommodated by a standby unit, the following types of concepts could be incorporated into the permit to identify the end of startup:</td>
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