National Emission Standards for
Hazardous Air Pollutants for Major Sources:
Industrial, Commercial, and Institutional Boilers and Process Heaters;
Proposed Rule
80 Fed. Reg. 3090 (Jan. 21, 2015)
(2015 Boiler MACT Proposed Reconsideration Rule)

EPA–HQ–OAR–2002-0058

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

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I. INTRODUCTION

The American Chemistry Council (ACC), American Municipal Power (AMP) and Council of Industrial Boiler Owners (CIBO) (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 major industrial, commercial and institutional (ICI) boilers and process heaters. 80 FR 3090 (Jan. 21, 2015) (2015 Boiler MACT 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.

AMP is a nonprofit corporation that provides services on a cooperative, nonprofit basis for its member communities operating municipal electric systems. AMP serves 130 member municipal electric communities in eight states, as well as the Delaware Municipal Electric Corporation. Combined, these publicly owned utilities serve approximately 625,000 customers. AMP members affected by this rule operate small utility boilers of 25 megawatts or less.

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 and process heaters that will be subject to this rule.

II. BACKGROUND

The DC Circuit Court vacated the 2007 NESHAPs for major ICI boilers and process heaters. EPA issued a replacement NESHAP in March 2011. 75 FR 15608 (Mar. 21, 2011) (2011 Boiler MACT Final Rule). EPA noticed reconsideration of several provisions of the 2011 Boiler MACT Final Rule. In January 2013, EPA issued the 2013 Boiler MACT Final Reconsideration Rule. 78 FR 7138 (Jan. 31, 2013)

In August 2013, EPA noticed reconsideration of several issues and now proposes additional revisions to the Boiler MACT rules. 80 FR 3092 (January 21, 2015) (2015 Boiler MACT Proposed Reconsideration Rule).

While the reconsideration rulemakings proceeded, parties challenged the 2011 and 2013 Boiler MACT Final Rules in DC Circuit Court. Those challenges are consolidated in *US Sugar Corp. v. EPA* (No. 11-1108) and as of February 2015 are briefed and pending oral argument before the Court.

Commenters submit these comments on the 2015 Boiler MACT 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" and the expanded list of "clean fuels." EPA directly addressed comments by regulated sources on its prior Boiler MACT provisions 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 Boiler MACT 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 3094 (January 21, 2015). However, EPA then 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 Boiler MACT sources. 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, e.g., four hours, 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 period on what was achieved by the best performing 12 percent of existing EGU sources without regard to whether that period reflects the time boilers need to reach safe and stable conditions. See 80 FR 3094. 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. Increasing temperature or pressure too quickly is unsafe and could result in significant equipment damage. 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 boiler and process heater.

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 and establish work practice standards that compel sources to minimize emissions and follow best practices guided by the manufacturer's recommendations for starting up and shutting down, which should be described in the proposed Startup Shutdown Plan (SSP).

To highlight several of the detailed comments below:

- Four hours is not enough startup time for all units and appears to be based on 12 percent of the EGU CEMS data for NOx and SOx in the MATS Rule, not on ICI boiler data for sources regulated under this rule;
- one hour is not enough time for units to engage baghouses or ESP's; and
- the petition process for more than 1 hour needs to be clearly identified as being implemented by the State permitting authorities.

1. Startup Definition

In the January 2013 Boiler MACT Final Reconsideration Rule, EPA defined startup to include the period commencing when fuel is fired in a boiler or process heater and ending when heat or

steam is supplied for any purpose. 40 CFR § 63.7575. EPA now 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 house 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 3113; 40 CFR § 63.7575 (proposed).

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 3094. EPA cites to CIBO comments on the prior Boiler MACT 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 3094. 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 sound 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 show 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 Boiler MACT. 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:

Boiler Type	Primary Fuel	Control	Responses Received (# units)
Circulating FBC	Coal or coal/biomass	Baghouse	20
Bubbling FBC	Coal	Baghouse	3
Pulverized Coal	Coal	Baghouse	2
		ESP	11
Stoker or Hybrid Suspension Grate	Coal	Baghouse	7
	Biomass	Baghouse	1
	Coal	ESP	6
	Biomass	ESP	15
	Biomass	Scrubber	5
Fuel Cell	Biomass	ESP	2
Liquid	Liquid	Any	4
Total Responses			**76**

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 show, in summary, that 4 hours is not enough time for all designs of

boilers and all control devices to achieve safe and stable operation. A similar survey by AMP of municipal utilities provides further confirmation that 4 hours may be insufficient for startup. See Attachments B - E, showing examples of startup instructions and data (Dustex Instructions, Startup Curve, B & W Startup Instruction, Boiler Cold Start Up (Example).[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. AMP members require 6-12 hours for startup of stoker units and pulverized coal units. 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% 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

[1] These documents contain example startup procedures 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.

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 the 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 ease 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 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 to accommodate safe and stable startup 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 3094.

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). The EGU data are not an appropriate basis for defining startup and setting work practices 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-2002-0058-3903 (relied on by EPA in this proposed rule at 80 FR 3094).

ICI boilers and process heaters that will be most dependent on this alternate definition do not operate similarly to EGUs.[2] 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 and process heaters 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 a 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 and process heaters.

ICI boiler and process heater "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 versus hot restart or warm restart.

[2] Some ICI boiler functions are more analogous to EGU boilers, and some emission controls used by EGUs and ICI boilers are similar in function. However, this rule applies to all ICI boilers and its definitions therefore must accurately describe other boilers whose functions are not at all analogous to EGUs. ICI boilers that support manufacturing processes are very diverse and not at all like EGUs.

Above all, the boiler/process heater 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/process heater and its controls are fully functional and supplying sufficient steam or heat to the processes and/or building requiring the energy. In many cases, stable operation of a boiler or process heater 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 and process heaters. In this rule, EPA uses the CAA §112(d)(3) methodology for setting floors for numeric standards to 1) define startup period and 2) establish the work practice standard for startup periods. That methodology is inapplicable to those elements of 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. Section 112(d)(3) 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. 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.

Similarly, the § 112(d)(3) methodology does not apply to setting work practice standards. To set a work practice standard, EPA must first find under § 112(h) that it is not feasible to prescribe or enforce numeric standards, which permits EPA to regulate the emissions with a work practice standard. Under § 112(h)(2), it is "not feasible" to prescribe or enforce a numeric limit where:

(A) the HAP "cannot be emitted through a conveyance designed and constructed to emit or capture such pollutant" or
(B) "the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations."

Under the authority of § 112(h), EPA considered in the Boiler MACT 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 15613 (March 21, 2011). Thus, EPA did not calculate floors 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.

In the proposed reconsideration rule, EPA expressly did not repudiate its findings nor abandon them as the basis for its work practice standards for startup and shutdown periods. 80 FR 3093. 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 purport to calculate the § 112(d)(3) level of emission reduction achievable by the best performers. EPA remains unable to calculate that § 112(d)(3) value, given the impracticability of gathering the data on which that value can be accurately calculated. Once EPA concluded that it is infeasible to set numeric limits for startup, it is not logical for EPA to then use that methodology to set limits on the number of hours in the startup period through the definition or work practice standards.

EPA's interpretation of the § 112(d)(3) methodology as applicable to defining startup or setting work practice standards also 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 and process heaters – that is made up of very diverse units, and for regulating a mode of operation – such as startup -- that must be defined in relation to the unique time that a boiler or process heater needs to reach safe and stable operation. Congress did not intend for EPA to look only to 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.

In summary, 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 and setting § 112(h) work practice standards.

2. Startup Work Practice: extension of time to engage PM control

Under the proposed rule, PM controls must be engaged within one hour of first firing coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel or gas 2 gases, and all other controls must be engaged as expeditiously as possible. 80 FR 3095. The final rule also includes a source-specific process for extending the time to engage PM controls beyond one hour after first firing base fuel. As explained below, the default period should be longer than one hour and the PM control extension process should be simplified and delegated to the permitting authority.

One of our members recently installed a new ESP on a biomass-fired process heater, and the manufacturer's instructions indicate that warming should occur at increments of 200F per hour and the ESP should not be energized until the outlet temperature is greater than 300F for at least two hours. The vendor indicates that during startup and shutdown, the ESP goes through a dew point cycle where internal surfaces become wet. If particulate is being collected during this time, a mud layer is formed, which does not rap off the ESP plates easily and becomes hard after high temperatures are reached. If these layers are allowed to build up over time, reduced collection efficiency is the result. Excessive amounts of mud in the ESP hoppers can also clog the screw

conveyors and result in the inability to remove ash. According to manufacturer recommendations, the startup period before engaging the ESP PM control device should be at least four hours.

During startup, the flue gas oxygen level is also usually high. Some boilers/ESPs have oxygen sensors and alarms that shut down the ESP at high flue gas oxygen levels to avoid a fire in the unit. Due to the high oxygen level during startup, the ESP will not be energized due to these safety controls until more stable operating conditions are reached. Manufacturers typically recommend maintaining the concentrations of carbon monoxide below 2% and oxygen below 6-8% to minimize the potential for fires and explosions downstream of the firebox and especially in the dry ESP. These values are considered trip points in the design and operation of an ESP. When the trip point is triggered, ESP power is turned off to eliminate the potential of sparking which would provide a source of ignition. De-energizing the transformer/rectifier causes the ESP voltage to drop to zero, thus eliminating the potential for sparking. These are safety measures that not only are recommended by the ESP manufacturers but are also industry standard practices and hence incorporated into companies' risk management plans and policies and operating procedures.

This example facility does not have access to natural gas as a startup fuel, so it cannot meet the current proposed work practice to energize the ESP within 1 hour of firing biomass. Many boilers operate ESPs to control PM and will face similar conflicts between the proposed rule and manufacturer recommendations. We suggest that EPA use four hours as the default period within which PM controls must be engaged after initiating solid fuel combustion. This reduces the administrative burden for issuing source-specific variances from an unrealistic 1-hour period within which to engage PM controls.

The rule requirements for the unit-specific case-by-case extension to the 1-hour period for engaging PM controls should also be streamlined. Table 3,footnote a. 80 FR 3120. The proposed rule extension is available where the owner provides evidence of two things: 1) engaging the PM control within one hour of firing the base fuel "violates manufacturer's recommended operation and/or safety requirements" and 2) the PM control is "appropriately designed and sized" to meet the filterable PM limit. Table 3, fn a; 80 FR 3120.

If EPA finalizes the first of these requirements, we recommend that the wording be changed from "*violates* manufacturer's recommended operation and/or safety *requirements*" to "*is not in accordance with* manufacturer's operation and/or safety *recommendations*." Manufacturers provide recommended procedures which source owners/operators may adapt as needed for the specific application. The term "violation" is not applicable, but the intent of being in accordance with their recommendations is appropriate.

The preamble specifies additional, somewhat overlapping elements, requiring the source to show:

(1) clean fuels are being used to the maximum extent possible to alleviate or prevent the safety issue prior to the combustion of base fuel; (2) the source has explicitly followed manufacturer's procedures to alleviate or prevent the safety issue, (3) details the manufacturer's statement of concern, and (4) the PM control is adequately designed and sized to meet the PM limit. 80 FR 3095

This extension reflects EPA's recognition that some facilities need more than one hour for engaging controls, including ESPs and baghouses to control PM. Sources will also need the extension based on flue gas temperature above the acid dew point for long enough to prevent bag blinding and ESP impairments. Biomass boilers will have this issue but also coal fired stokers without gas/oil burners. Even if initial lightoff is not a problem, it will not take long (less than an hour) for primary coal to be spread on the grate, simply because there needs to be an ash bed established to protect the grate from coal firing temperatures and the fire needs to be spread across the grate, which takes time.

EPA should, in the first instance, define startup more flexibly, based on ICI boiler data. As previously recommended by CIBO and others, EPA should simply include ESPs in the list of controls that must be started as expeditiously as possible. The information presented above demonstrates that units need to be constrained by safety and equipment protection, not by an arbitrary 1- or 4-hour EPA equipment startup requirement that appears to be based on top performing EGU data.

However, if EPA declines to make those changes, then this compliance extension will be critical to many sources' ability to comply with the rule. Commenters support the alternate definition of

startup and alternate work practice standard with the enhancements recommended above conditioned on EPA finalizing a streamlined and workable PM control extension procedure that accommodates units that need more than one hour to safely initiate PM control equipment during startup. As such, EPA should provide significantly more detail and ensure the success of the variance procedure in the final rule.

The PM control extension process should be handled by the State permitting agency. The PM control extension process will be workable only if its implementation is delegated to and managed by the permitting authority and not required to be submitted to the EPA regional offices. Boiler owners have significant experience with other CAA alternate compliance procedures. Requiring EPA involvement will greatly slow down the process. The timing of the PM control extension application approvals is especially critical here, where sources face a January 2016 compliance date. EPA should require that this process be followed for sources seeking a PM control extension: the source may submit to the permitting authority a request for an extension of the PM control requirement. The permitting authority shall take final action on the request within 30 calendar days.

The PM control extension should be automatically granted if the application is not acted on within a specified timeframe. EPA has not estimated the extent to which this extension will be needed by boilers under this rule. Because some sources will not be able to comply using the alternate definition of startup without this extension, EPA must ensure that there is approval even if the permitting authority does not act on a source's application for such an extension in a timely fashion. Given the approaching deadline and regulators' inexperience with what will be a new extension application process, sources should be given the benefit of a default approval and not be forced to face the ramifications of noncompliance for circumstances beyond their control.

3. 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 or process heater 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.

4. 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 or process heater." Commenters support this definition.

5. Clean Fuels Requirement

EPA proposes to expand the list of clean fuels in the work practice standard for startup to include Gas 1 and fuels that meet HCl, Hg, and TSM emission limits using fuel analysis. Sources would demonstrate compliance either through fuel analysis for the relevant parameters or stack testing. 80 FR 3094 – 95; Table 3, Item 5 (proposed).

We support expansion of the clean fuel list, the addition of Gas 1, the use of fuel analysis and corresponding revisions to the work practice standard. Table 3, item 5.b. This change addresses concerns by facilities that startup on other fuels and that have limited or no access to the fuels EPA initially defined as startup fuels. This revision is critical to the ability of many sources to comply with the rule.

The list of clean fuels must also expressly include dry biomass (<20% moisture content). Dry biomass is comparable in its basic constituent makeup and combustion characteristics as paper and cardboard, which are listed as clean fuels for startup or shutdown. Specifically, the low chloride, mercury, and moisture content of dry biomass means that it has low HCl, Hg, and CO

emissions. Furthermore, PM emissions for units with mechanical collectors that fire dry wood are estimated to be well within the dry biomass subcategory PM limit because the AP-42 PM emission factor for such is below the dry biomass subcategory PM limit. Dry biomass also is included in EPA's definition of "clean cellulosic biomass" under the NHSM rule. It is not reasonable to require that this fuel go through a fuel analysis to demonstrate that it is clean when similar materials are deemed clean without fuel analysis, particularly for units burning dry biomass with mechanical PM collectors.

In addition, it is reasonable to include dry biomass in the list of clean fuels because some of the units relying on these materials are expected to meet emission limits for the dry biomass subcategory, even during startup. Some additional revisions to Table 3 are needed to conform it to the revised list of clean fuels. Specifically, EPA should:

- Revise Item 1 to be consistent with the statement in the preamble that compliance with the clean fuel requirement may be demonstrated not only by fuel analysis, but also by stack testing.
- Revise Items 5.c.1 and 5.c.2 to acknowledge the possibility for additional clean fuels by replacing the list of fuels ("coal/solid fossil fuel, biomass/biobased solids, heavy liquid fuel, or gas 2 (other) gases") with "*fuels that are not clean fuels*."
- Revise Item 6, to acknowledge that some additional fuels may be clean fuels.

EPA should not impose these new burdens, particularly as it launches an effort to streamline existing regulatory burdens. EPA has just issued a Notice and Request for Comment implementing Executive Order 13610, ``Identifying and Reducing Regulatory Burdens," directing agencies to identify existing rules that are "excessively burdensome" and take action including modifying or streamlining the requirements. In its Notice, EPA asks commenters "How can the EPA streamline or consolidate reporting requirements to reduce burden?" 80 FR 12372-73 (March 9, 2015). EPA could fulfill the directive by not imposing in this rule these new duplicative reporting requirements.

6. Startup and Shutdown Reporting Requirements

The rule proposes to require reporting for startup and shutdown periods. Table 3, Items 5(d) and 6; 80 FR 3109-12, 40 CFR § 63.7550 (proposed). Commenters oppose this additional

requirement, which will greatly increase their compliance burden without any additional environmental protection and without any regulatory need or justification.

Sections 63.7555(d)(11)–(12) require sources to record the following information:

- time that clean fuel combustion begins; the time when firing start for base fuel; time when useful thermal energy is first supplied; time when PM controls are engaged; hourly steam temperature, pressure, flow, flue gas temperature; all hourly average CMS data (e.g., CEMS, PM CPMS, COMS, ESP total secondary electric power input, scrubber pressure drop, scrubber liquid flow rate) collected to confirm controls are engaged.
- if compliance is demonstrated with an ESP, the number of fields in service, and each field's secondary voltage and secondary current during each hour of startup.
- if compliance is demonstrated with a fabric filter, the number of compartments in service, and the differential pressure across the baghouse during each hour of startup.
- if compliance is demonstrated with a wet scrubber needed for filterable PM control, the scrubber liquid to fuel ratio and the differential pressure of the liquid during each hour of startup.

Section 63.7550(c)(5)(xviii) then requires sources to report, for every instance startup or shutdown, all of this information. 40 CFR § 63.7550(c)(5)(xviii)(proposed). Requiring sources to report each instance they startup or shutdown in compliance with the work practice standards is not justified, nor does EPA offer any justification.

The reporting requirement places an enormous burden on sources, a burden which EPA does not acknowledge or explain in the proposed rule. Sources are required to report deviations under their Title V permits, which will fully meet any need EPA has to monitor details of deviations from startup and shutdown work practice standards. Thus, there is no additional environmental benefit from a requirement to report this information, nor will it enhance source compliance. There is also no legal justification for EPA to require reporting for each startup and shutdown period. Sources should be required to submit this information only in the instance of deviations from standards and only once, in accordance with their Title V permits.

7. Startup and Shutdown Plan

The alternate work practice standard includes a proposed requirement to develop and implement a written startup and shutdown plan (SSP). 80 FR 3095. The preamble indicates that this requirement applies only to units subject to applicable emission limits if they are using the alternative startup definition. 80 FR 3095 ("In addition, we are proposing in the alternate work practice requirement that owners and operators of boilers and process heaters, if they have an applicable emission limit, must develop and implement a written startup and shutdown plan (SSP)."). The SSP must be maintained onsite and available upon request for public inspection.

Commenters generally support this requirement, except for Gas 1 units, subject to the following qualifications:

- Table 3, item 5.c.(2) should be modified to include the requirement for a written startup and shutdown plan (SSP).
- The Table 3 reference should clarify that the SSP is required only for units utilizing the alternative startup definition, consistent with EPA's intent as provided in the preamble.

B. CO LIMITS BASED ON A MINIMUM CO LEVEL OF 130 PPM

In the January 2013 Boiler MACT Final Reconsideration Rule, EPA established a CO emission limit for certain subcategories at a level of 130 ppm, based on an analysis of CO levels and associated organic HAP emissions reductions. See 78 FR 7144. EPA notes that these CO limits are being challenged on the grounds that they do not meet the CAA requirements for MACT standards and that EPA's rationale for adopting this limit is unrelated to this statutory MACT requirement. Commenters maintain that work practice standards, rather than a numeric emission limitation, is the appropriate standard for source categories with significant amounts of non-detect or unreliable organic HAP data. [3] However, for source categories where EPA has demonstrated a strong correlation between organic HAP and CO, Commenters fully support EPA's revision of the numeric CO standard to 130 ppm.

[3] For example, the correlation between CO and HAPs is in dispute for some subcategories of coal-fired sources due to significant amounts of non-detect and otherwise unmeasureable organic HAP data. That issue is pending in litigation in the DC Court of Appeals. *U.S. Sugar Corp. v. EPA* (DC Cir. No. 11-1108).

In the 2013 Boiler MACT Final Reconsideration Rule, EPA stated:

> We believe a CO level of 130 ppm corrected to 3 percent oxygen is an appropriate minimum MACT floor level. Although some measurements show CO levels below 130 ppm corrected to 3 percent oxygen, it is not appropriate to establish a lower floor level because CO is a conservative surrogate for organic HAP. In other words, organic HAP emissions are extremely low when sources operate under the good combustion conditions required to achieve CO levels in the range of zero to 100 ppm. As such, lowering the CO floor below 100 ppm will not provide reductions in organic HAP emissions.

78 FR 7145.[4]

EPA's conclusion in the 2013 Boiler MACT Final Reconsideration Rule is consistent with its determination in the Hazardous Waste Combustor NESHAP rulemaking. In the Hazardous Waste Combustor NESHAP, EPA determined that forcing CO emissions below 100 ppm does not force organic HAP emissions to ultra-low levels. As the Agency states at 70 FR 59462 (October 12, 2005):

> We explained at proposal why the carbon monoxide standard of 100 ppmv and the hydrocarbon standard of 10 ppmv are appropriate floors. See 69 FR 1282. The floor level for carbon monoxide of 100 ppmv is a currently enforceable Federal standard. Although some sources are achieving carbon monoxide levels below 100 ppmv, it is not appropriate to establish a lower floor level because carbon monoxide is a conservative surrogate for organic HAP. Organic HAP emissions may or may not be substantial at carbon monoxide levels greater than 100 ppmv, and are extremely low when sources operate under the good combustion conditions required to achieve carbon monoxide levels in the range of zero to 100 ppmv. (See also the discussion below regarding the progression of hydrocarbon oxidation to carbon dioxide and water). As such, lowering the carbon monoxide floor below 100 ppmv may not provide significant reductions in organic HAP emissions. Moreover, it would be inappropriate to establish the floor blindly using a mathematical approach—the average emissions for the best performing sources—because the best performing sources may not be able to replicate their emission levels (and other sources may not be able to duplicate those emission levels) using the exact types of good combustion practices they used during the compliance test documented in our data base. This is because there are myriad factors that affect combustion efficiency and, subsequently, carbon monoxide

[4] EPA determined that 100 ppm @ 7 percent oxygen equates to 130 ppm at 3 percent oxygen. 78 FR 7145.

> emissions. Extremely low carbon monoxide emissions cannot be assured by controlling only one or two operating parameters.

Section 112(d)(3) requires EPA to set floors for existing sources at the level achieved in practice by the best-performing 12 percent of sources in each subcategory. In the Boiler MACT rule, EPA set emission limits, using CO as a surrogate, at a level below which organic HAP emissions are expected to be at or near zero. This is conclusively demonstrated in the 2012 MACT Floor Memo. August 2012 BMACT Floor Memo, EPA-GQ-OAR-2002-0058-3836 at 11, app. H, ch. H-1a. EPA determined that organic HAP data corresponding to CO levels less than 130 ppm (i.e., 1-2 ppm) are unreliable, due to difficulties measuring such low levels of organic HAP. EPA therefore set the MACT floor at the most stringent level it could support with the data at hand – a level indicating organic HAP emissions are at or near zero. It is difficult to fathom how EPA could have set a more stringent limit for organic HAP, or how this limit could somehow be less stringent than what the top 12 percent of units is achieving in practice.

Real impacts on organic HAP emissions are not achieved by pressing ultra-low CO limits on fossil fuel combustion units compared to normal operating levels. Emissions of organic HAP will be the same whether EPA sets the CO limit at 130 ppm or 10 ppm, because CO is a conservative surrogate for organic HAP. There is no defensible driver to impose emission limits at any lower level. *See* 2012 CIBO Comments on Proposed Reconsideration Rule, EPA-HQ-OAR-2002-0058-3534, at 17. Selecting 10 ppm would have been arbitrary and capricious, because requiring this level of CO reduction would have had no relation to reductions in organic HAP. EPA recognized this flaw when it adjusted CO emission limits to 130 ppm and achieved the same organic HAP reductions. This was not only reasonable, but required to avoid an arbitrary rule that regulated for the sake of regulating.

Furthermore, EPA's selection of 130 ppm CO as the MACT floor for certain source categories is consistent with DC Circuit holdings that EPA may use surrogates as long as EPA can establish a necessary relationship between emissions of the surrogate and emissions of the underlying HAPs. In the case of CO and volatile HAP emissions from industrial boilers, data show that the relationship is highly nonlinear at low levels. It is rational and in keeping with controlling law for EPA to set a CO standard that reflects this nonlinear relationship by setting a minimum CO

level at 130 ppm. *See* 2012 CIBO Comments on Proposed Reconsideration Rule, EPA-HQ-OAR-2002-0058-3534, at 19.

C. PM CPMS

The March 2011 Boiler MACT Final Rule required units greater than 250 MMBtu/hr combusting solid fossil fuel or heavy liquid to install, maintain, and operate PM continuous emissions monitors (CEMS)to demonstrate compliance with the applicable PM emission limit. 76 FR 15615. In response to petitions for reconsideration challenging PM CEMS, EPA proposed an alternative continuous parametric monitoring system (CPMS) for demonstrating continuous compliance with the PM standards in the rule. In the January 2013 Boiler MACT Final Reconsideration Rule, EPA retained the PM CPMS requirements and included a new requirement that the PM CPMS must be certified, for which EPA had not provided notice and comment. 80 FR 3096. CIBO petitioned EPA for reconsideration of the requirement to certify the PM CPMS and challenged the treatment of exceedances of operating parameters as presumptive violations.

We strongly support the removal of the requirement to certify PM CPMS and oppose the treatment of PM CPMS exceedances as violations. We also recommend that the time period for inspecting the control device and conducting a performance test in response to a parametric exceedance be extended.

1. The requirement to certify PM CPMS should be removed.

EPA proposes to remove the word “certify” from 40 CFR § 63.7525(b) and (b)(1) because “there is no certification procedure for PM CPMS.” 80 FR 3099, Table 1. Although EPA had stated in the Proposed 2011 Reconsideration Rule that it did not intend to impose "the burden of certification of the monitor," the January 2013 Boiler MACT Final Reconsideration Rule did just that: § 63.7525(b) and other sections required sources complying with PM CPMS standards to "certify" their CPMS. 78 FR 7172.

We agree with EPA’s determination that the final rule mistakenly retained a “certify” requirement for the PM CPMS and we support EPA’s technical correction to remove the

requirement to certify PM CPMS. We also agree that there is no certification procedure for PM CPMS because Performance Specification 11 is applicable to use of PM CEMS only.

EPA explained in its Response to Comments on this rule that it did not intend to require sources to certify their CPMS using PS 11. See EPA Summary of Responses to Public Comments, EPA-HQ-OAR-2002-0058-3849 at 768.

In addition, in the final Portland Cement NESHAP rule, EPA acknowledged the difficulty of certifying PM CEMS. EPA noted that "there needs to be some assurance of the reliability of that methodology to certify with PS 11 at low levels (as required by this final rule)" and "[t]hat information does not presently exist." 78 FR 10017 (Feb. 12, 2013). Therefore, EPA appropriately proposes to remove the requirement to certify PM CPMS.

2. PM CPMS Exceedances Should Not Be Presumed to be Violations.

In the January 2013 Boiler MACT Final Reconsideration Rule, EPA added provisions that specify that after operating parameter exceedances trigger four performance tests, any further exceedance would be presumed to be a violation. 80 FR 3096. Thus, each exceedance of the 30 boiler-operating-day PM CPMS requires inspection and a new performance test to verify or reestablish the operating limit within 30 calendar days. 80 FR 3097. Additional exceedances that occur between the original exceedance and the performance test do not trigger another test and up to four performance tests may be triggered in a 12-month rolling period with no additional consequences. However, each additional performance test that is triggered would constitute a separate presumptive violation. 80 FR 3097. PM CPMS exceedances should not be presumed to be violations.

Any well maintained CPMS or CEMS will inevitably have periods where it is out of control or out of operation. To account for this, many other regulations recognize this and build in some reasonable tolerance for missing data. Typical state permit conditions require data availability for a minimum percentage of operating hours in a calendar month or quarter. The minimum percentage depends on the CEMS of CPMS technology. Some monitors such as opacity can reasonably obtain a 95 percent availability (see 40 CFR § 60.2735).

Like missing data, EPA should not treat exceedances of the operating parameters as presumed violations. A higher reading from a PM CPMS is an indication that the characteristics of the PM in the stack gas are different from the stack test conditions, not necessarily that a violation has occurred. Furthermore, it is not rational to set a monitoring requirement that cannot possibly be complied with 100 percent of the time. Although the 2013 Boiler MACT Final Reconsideration Rule allows for a certain number of exceedances of the operating parameter limit before an exceedance would be presumed to be a violation, EPA should revise the rule to make it clear that exceeding an operating parameter limit should never be considered a violation of the standard.

3. PM CPMS Response Times Should be Extended.

EPA solicits additional comments on the requirements for demonstrating continuous PM emission compliance using a PM CPMS under 40 CFR § 63.7540(a)(18). See 80 FR 3098 (erroneously citing 63.7440(a)(18) which does not exist in the rule). One such requirement is the obligation to conduct a visual inspection of the control device within 48 hours of the deviation. See 40 CFR § 63.7540(a)(18)(ii)(A). Many ICI boilers operate on business days, not calendar days. As such, the obligation to inspect a unit within 48 calendar hours could require a facility to inspect over the weekend when the unit may not be operating, when the most knowledgeable internal personnel are not scheduled to work, and when the cost of external personnel can be significantly higher than during normal business hours. A prompt inspection within two business days or within five calendar days would allow such inspection to occur during normal business hours thereby maximizing the benefit of the inspection without unnecessary cost and burden.

The PM CPMS provisions also require a compliance test within 30 days of the parametric deviation. At the same time, 40 CFR § 63.7(b) requires 60 days prior notice to the Administrator before a performance test can be conducted. See 40 CFR Part 63, Subpart DDDDD, Table 10 "Applicability of General Provisions to Subpart DDDDD". EPA may require that a test be ***scheduled*** within 30 days, but the source should have up to 75 days to complete the test to allow for the required 60-day notice after observing a parametric exceedance. This also allows time for proper notice to state permitting authorities to avoid duplicate testing obligations. As the rule currently reads, a source could provide 60-day notice on April 1st for a standard Title V compliance test to be conducted on June 1st and then experience a PM CPMS deviation on April 15th. This would require the PM CPMS test within 30 days -- on May 15th followed by the Title

V test on June 1st. If the PM CPMS testing requirement allowed up to 75 days or was otherwise more flexible, this unnecessary testing burden could be avoided.

D. 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 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 major 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* 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 emission standards in that rule. EPA cannot simply directly apply the *NRDC* ruling to the Boiler MACT,

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.

E. COMPLIANCE REPORTING FOR CEMS AND CPMS

The 2015 Boiler MACT Proposed Reconsideration Rule includes this reporting requirement at 40 CFR § 63.7550(c)(5)(xvi):

> (c) A compliance report must contain the following information depending on how the facility chooses to comply with the limits set in this rule.
> ***
>> (xvi) For each reporting period, the compliance reports must include all of the calculated 30 day rolling average values based on the daily CEMS (CO

> and mercury) and CPMS (PM CPMS output, scrubber pH, scrubber liquid flow rate, scrubber pressure drop) data.

It is not clear to Commenters why EPA would specify daily data in § 63.7550(c)(5)(xvi) when " 30-day rolling average" is defined in 40 CFR § 63.7575 as "the arithmetic mean of the previous 720 hours of valid operating data." Specifying daily data will not improve compliance. Moreover, including hourly or daily data in each of these reports semiannually, annually, biennially, or every 5 years as required in section 63.7550(b) is unreasonable because it will require sources to report a tremendous amount of data with no benefit to the environment. This vast volume of data is likely to also require additional data management infrastructure. For example, for hourly calculations some facilities are likely to have to implement daily manual review and tagging of startup and shutdown periods and data to comply with the rule requirements to segregate that data from periods of normal operation. Calculating a rolling hourly average number also requires 24 times more space in a data acquisition system and more effort to review the information for accuracy than calculating a daily number. These burdens would be imposed across the approximately 2000 boilers with numeric limits under the rule, this is quite a bit of data and effort.

For these reasons, EPA should interpret these provisions to allow sources to report only their deviations, rather than hours and hours of data. Imposing these burdens where there is no corresponding benefit is not reasonable.

F. TECHNICAL CORRECTIONS & CLARIFICATIONS

EPA proposes to make many technical corrections and clarifications to the current 2013 regulations. See 80 FR 3090 at 3098-3100. Commenters offer comments on several of those proposed changes.

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 3 to 40 CFR 63 Subpart DDDDD (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. Site-Specific Fuel Analysis Plan

In the 2013 Boiler MACT Final Reconsideration Rule, 40 CFR § 63.7521(g) requires sources to "develop and submit a site-specific fuel analysis plan for other gas 1 fuels to the EPA Administrator for review and approval . . . ." In the current rule, EPA proposes to revise 40 CFR § 63.7521(g) to remove the requirement to submit the plan for review by and approval of the EPA Administrator. Commenters support EPA's proposed change. In the 2013 Boiler MACT Final Reconsideration Rule only units combusting other Gas-1 fuels are required to submit their plans for review and approval—solid and liquid fuels are not required to do so. This proposed technical correction is justified and removes this inconsistency.

In addition, Commenters also request that EPA consider clarifying two other issues in 40 CFR § 63.7521(g). First, the term "notification" in 40 CFR § 63.7521(g)(2)(ii) could imply that a notification is required when deciding on whether an owner or fuel supplier is conducting the fuel analysis. This contradicts the changes described immediately above that remove the requirement to submit the site-specific fuel analysis plan for review and approval. EPA should replace the word "notification" with the word "identification" so the sentence reads as follows: "For each anticipated fuel type, the identification ~~notification~~ of whether you or a fuel supplier will be conducting the fuel specification analysis.

Second, EPA should clarify 40 CFR § 63.7521(g)(2)(iii). Currently, it requires the site-specific fuel analysis plan to provide a "detailed description of the sample location and specific procedures to be used for collecting and preparing samples." This requirement is difficult to impossible, however, for owners and operators who purchase fuel (e,g, landfill gas) from a supplier and use a fuel analysis from that supplier instead of developing their own site-specific sampling and analysis. Because the fuel sampling is performed at the supplier's location, purchasers cannot be expected to provide this information. Instead, the purchaser should be required only to maintain documentation showing that the supplier has used the analytical methods required by Table 6 to subpart DDDDD, as required by 40 CFR § 63.7521(g)(2)(vi).

Commenters request that EPA revise § 63.7521(g)(2)(vi) to indicate that, when using a fuel supplier's fuel analysis, the owner or operator is not required to submit the information in § 63.7521(g)(2)(iii).

3. Notification of Intent to Conduct Performance Test

In the 2013 Boiler MACT Final Reconsideration Rule, 40 CFR § 63.7545(d) requires a "Notification of Intent to conduct a performance test." However, the rule does not make clear that this requirement does not apply when a fuel specification analysis is being performed. Commenters suggest that EPA insert the phrase "(defined in 63.2)" immediately after "performance test" to clarify that such a notice is not required when a fuel specification analysis is being performed. The sentence should read as follows: "If you are required to conduct a performance test ***(defined in 63.2)*** you must submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin."

4. Notification of Compliance Status

The description of the contents of the Notification of Compliance Status (NOCS) in 40 CFR § 63.7545 does not specify when the NOCS must be submitted for sources that do not have an initial compliance demonstration requirement. Commenters suggest that EPA specify that the NOCS for these sources is due within 60 days of the applicable compliance date specified in §63.7495(b) by revising § 63.7545(e) to include the italicized text as below:

> If you are not required to conduct an initial compliance demonstration as specified in § 63.7530(a), the Notification of Compliance Status must only contain the information specified in paragraphs (e)(1) and (8) *and must be submitted within 60 days of the compliance date specified at 63.7495(b).*

Such a change would be consistent with other NESHAP rules, which also require a Notification of Compliance Status within 60 days.

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

In the 2013 Boiler MACT Final Reconsideration Rule, 40 CFR § 63.7525(a)(7) describes the requirement for oxygen trim systems for boilers or process heaters subject to a CO emission limit in Tables 1, 2 or 11 through 13. 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 § 63.7525(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 § 63.7525(a)(7) by adding the italicized text as follows:

> (7) Operate an oxygen trim system with the oxygen level set no lower than the lowest hourly average oxygen concentration measured during the most recent CO performance test as the operating limit for oxygen according to Table 7 to this subpart, *or if the facility is not required to conduct a performance test, set the oxygen level* ***to the oxygen concentration measured during the most recent tune-up*** *to optimize CO to manufacturer's specification.*

We agree with EPA that this provision should be amended. However, the test setting for oxygen should be at the optimum level recognizing that O_2 changes over load. O_2 increases as firing rate decreases due to inherently lower fuel/air mixing at lower firing rates. Thus, to make this amended provision workable, EPA's proposed textual change should be amended as shown here in italics:

> (7) Operate an oxygen trim system with the oxygen level set no lower than the lowest hourly average oxygen concentration measured during the most recent CO performance test as the operating limit for oxygen according to Table 7 to this subpart, *or if the facility is not required to conduct a performance test, set the oxygen level* ***no lower than the average measured during the tune-up final setup testing*** *to optimize CO to manufacturer's specifications.*

This amended version is more accurate and therefore will be more likely to achieve the goal of the provision.

6. Changes to Definition of Coal

EPA proposes to revise the definition of ''coal'' to define coal-derived liquids as liquid fuel. Commenters strongly oppose this change for substantive and procedural reasons.

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. This proposed change directly affects unique units that have been on

track throughout this rulemaking to comply with the limits for coal-fired boilers, but which cannot meet the limits for liquid-fired boilers.

These units fire three types of fuel: SNG, by-product gas, and coal-derived liquids. 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 3090. In addition to those specific topics, EPA also proposed technical amendments to many provisions. EPA categorizes its revision of the definition of coal as a "technical" correction or clarification. That is not correct. This topic is clearly beyond the narrow scope of a technical amendment and triggers EPA's obligation under the Clean Air Act and Administrative Procedure Act 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 Clean Air Act. 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 is far reaching in its content and impact on sources and 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 "technical" amendment to the definition of coal.

7. Table 6

EPA proposes several revisions to Table 6 to Subpart DDDDD:

1. Revise items 1, 2, and 4 to remove reference to the equations cited in 40 CFR § 63.7530 for demonstrating only initial compliance.
2. Revise items 1.c, 2.c, and 4.c to remove the listed method for liquid samples to be consistent with 40 CFR § 63.7521(a).
3. Revise item 3 to clarify that the two methods listed are alternatives.
4. Revise the title to item 4 to remove ''for solid fuels'' to clarify that item 4. is applicable to also liquid fuel types.

Commenters support the changes to Table 6, in particular the removal of the equations cited in 40 CFR § 63.7530 for demonstrating only initial compliance from items 1, 2, and 4. The cited equations are in conflict with sub-item g of each of the items and are not used in demonstrating continuous compliance. With this change, EPA will be properly referencing here the continuous compliance provisions of 40 CFR § 63.7540.

8. Table 8

Commenters support EPA's revision to item 10 in Table 8 clarifying that compliance with the operating load operating limit is to be evaluated on a 30-day rolling average basis. This is consistent with 40 CFR § 63.7525(d) and avoids any confusion over the appropriate averaging time for this operating limit.

9. Definition of Load Fraction

EPA proposes to revise the definition of load fraction in the 2015 Boiler MACT Proposed Reconsideration Rule by adding the italicized text to the current version of the rule (found at 40 CFR § 63.7575).

> 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 3112-13.

Commenters support this revision because it recognizes that neither a boiler's Hg, SO2, nor HCl emissions are affected by the portion of the boiler's heat input attributable to firing natural gas.

10. Fuel Sampling Requirements

EPA proposes to amend 40 CFR § 63.7521(c)(1)(ii) to correct an inconsistency in the 2013 Boiler MACT Final Reconsideration Rule with regard to the frequency of fuel sampling required for facilities using the fuel analysis option. 40 CFR § 63.7515(e) requires fuel analyses to be conducted on a monthly basis and no closer together than 14 calendar days:

> (e) If you demonstrate compliance with the mercury, HCl, or TSM based on fuel analysis, you must conduct a monthly fuel analysis according to §63.7521 for each type of fuel burned that is subject to an emission limit in Tables 1, 2, or 11 through 13 to this subpart. You may comply with this monthly requirement by completing the fuel analysis any time within the calendar month as long as the analysis is **separated from the previous analysis by at least 14 calendar days**.

In contrast, 40 CFR § 63.7521(c)(1)(ii) requires fuel samples to be collected three times per month:

> (ii) Each composite sample will consist of a minimum of three samples collected at approximately equal one-hour intervals during the testing period for sampling during performance stack testing. For monthly sampling, each composite sample shall be collected at approximately **equal 10-day intervals during the month**.

EPA proposes to resolve this by removing the requirement that fuel sampling be collected approximately every 10 days during the month. Commenters support this revision because it would be impossible to obtain 3 samples 10 days apart in some months.

Related to this issue, commenters request clarification in the final rule that a source may take multiple samples during a month so, in this case, the 14 day separation period would not apply. It is our understanding the 14 day separation is intended to address the case where one sample is analyzed each month and the Agency wanted to make sure there is a reasonable separation between analyses.

11. Dates for Submitting Compliance Reports

The 2013 Boiler MACT Final Reconsideration Rule erroneously established the deadline for sources to submit their first compliance report required under 40 CFR § 63.7550(b)(2) that coincides with the end of the sources' first reporting period in 40 CFR § 63.7550(b)(1). To resolve this issue, EPA proposes to revise the dates in 40 CFR § 63.7550(b)(2) from July 31 and January 31 to June 30 and December 31, respectively. This allows sources one month from the end of the reporting period to prepare and submit their compliance reports. Commenters support this revision.

12. Use of CO2 as an Alternative to O2 for Correcting CO CEMS

EPA proposes several technical corrections to 40 CFR § 63.7575(a)(1), (2), (3), and (5) and to Table 1 and Table 2 to allow CO2 to be used as an alternative to using O2 in correcting the measured CO CEMS without petitioning for an alternative monitoring procedure. 80 FR 3099-3100.

Commenters support EPA's decision to permit sources to use CO2 instead of O2. This change will allow boilers that have installed a CO2 diluent CEMS as part of their compliance efforts

under other regulations to avoid installing a redundant O2 CEMS as well. However, several such CO2 CEMS in use by Commenters' member companies measure CO2 on a wet basis. To allow these units to take advantage of the alternative EPA is offering, additional revisions to the rule are required.

The proposed 40 CFR § 63.7525(a)(2) cross-references several other requirements that sources demonstrating compliance with an applicable alternative CO CEMS emission must meet. Among these, if a CO2 analyzer is used, § 63.7525(a)(2) states that the source must meet the requirements in 40 CFR Part 75 regarding the installation, certification, operation, and maintenance of a CO CEMS. Part 75 provides options for sources to correct the moisture issue, but only with regard to monitoring SO2, NOx, and CO2 emissions. See 40 CFR §§ 75.11, 75.12, 75.13. Because Part 75 does not address CO monitoring, it does not fully address the moisture correction issue and we believe it is necessary to add the language proposed above to do so.

Commenters suggest that EPA address this issue by adapting an amendment along the lines of the following provision from 40 CFR § 63.7525:

> *40 CFR § 63.7525(a)(2)(vi): When CO2 is used to correct CO emissions and CO2 is measured on a wet basis, correct for moisture as follows:*
>
> *Install, operate, maintain, and quality assure a continuous moisture monitoring system for measuring and recording the moisture content of the flue gases, in order to correct the measured hourly volumetric flow rates for moisture when calculating CO concentrations. The following continuous moisture monitoring systems are acceptable: a continuous moisture sensor; an oxygen analyzer (or analyzers) capable of measuring O2 both on a wet basis and on a dry basis; or a stack temperature sensor and a moisture look-up table, i.e., a psychrometric chart (for saturated gas streams following wet scrubbers or other demonstrably saturated gas streams, only). The moisture monitoring system shall include as a component the automated data acquisition and handling system (DAHS) for recording and reporting both the raw data (e.g., hourly average wet-and dry-basis O2 values) and the hourly average values of the stack gas moisture content derived from those data. When a moisture look-up table is used, the moisture monitoring system shall be represented as a single component, the certified DAHS, in the monitoring plan for the unit or common stack.*

13. SO2 CEMS

EPA proposes to amend the text of 40 CFR § 63.7525(m) to clarify that it is only applicable if the source elects to use an SO2 CEMS to demonstrate compliance with the HCl emission limit and to clarify that the SO2 CEMS can be certified according to either Part 60 or Part 75, EPA proposes to do so by adding the italicized text to these paragraphs, as shown below:

> (m) If your unit is subject to a HCl emission limit in Tables 1, 2, or 11 through 13 of this subpart and you have an acid gas wet scrubber or dry sorbent injection control technology and you elect to use an SO2 CEMS *to demonstrate continuous compliance with the HCl emission limit*, you must install the monitor at the outlet of the boiler or process heater, downstream of all emission control devices, and you must install, certify, operate, and maintain the CEMS according to either part 60 or part 75 of this chapter.
>
> (2) For on-going quality assurance (QA), the SO2 CEMS must meet *either the applicable daily and quarterly requirements in Procedure 1 of appendix F of part 60 or* the applicable daily, quarterly, and semiannual or annual requirements in sections 2.1 through 2.3 of appendix B to part 75 of this chapter, with the following addition: You must perform the linearity checks required in section 2.2 of appendix B to part 75 of this chapter if the SO2 CEMS has a span value of 30 ppm or less.

Commenters support these changes because they make CEMS compliance more cost-effective. Allowing sources to meet the requirements of either part 60 or part 75 is appropriate because existing CEMS could have been installed under either part. In addition, sources already using CEMS benefit from this flexibility because it enables them to use CEMS with O2 or CO2 as the diluent gas. The proposed revision to 40 CFR § 63.7525(m) to allow a SO2 CEMS to meet either applicable CEMS requirements of part 60 or part 75 should be finalized.

14. SO2 30 Day Rolling Average Limit

EPA proposes to revise item 11.c to read ‘‘highest’’ instead of ‘‘minimum’’ to be consistent with item 10 of Table 4 to subpart DDDDD. Thus, under the revised Table 8 Item 11c, units monitoring SO2 emissions by using SO2 CEMS would demonstrate continuous compliance by “Maintaining the 30-day rolling average SO2 CEMS emission rate to a level at or below the *highest* hourly SO2 rate measured during the most recent HCl performance test according to §63.7530.” Commenters agree that this change should be finalized because it makes Item 11c consistent with the requirements of Table 4 and because the 30 day rolling average limit should be based on the highest hourly rate measured during the performance test.

EPA proposes a similar change to 40 CFR § 63.7530(h)(3), which Commenters also support for the same reasons.

15. Correction to Section 63.7540(a)(2)

In Table 1 of the preamble, EPA proposes to change the reference to 40 CFR § 63.7550(c) in 40 CFR § 63.7540(a)(2) to § 63.7555(d). 80 FR 3099. However, the regulatory text that EPA proposes on page 3109 of the preamble to implement this change instead changed the cross-reference from § 63.7550(c) to § 63.7550(d), which does not make sense. EPA should correct the typographical error in the proposed regulatory text so that it has the proper cross-reference: § 63.7555(d).

16. Timing of Burner Inspections

40 CFR § 63.7540(a)(10) requires boilers and process heaters with a heat input capacity of 10 MMBtu/hr or greater (other than limited-use boilers and process heaters) to conduct an annual tune-up. Among other requirements, the tune-up requires an inspection of the burner, but the source may delay the burner inspection until the next scheduled shutdown.

EPA should revise 40 CFR § 63.7540(a)(10)(i) to provide owners and operators the flexibility to perform burner inspections at any time prior to tune-up in order to avoid creating a potential compliance conflict in which a boiler was scheduled for shutdown, but had to resume operations, due to unforeseen circumstances, before the burner inspection was performed. To accomplish this, Commenters suggest EPA add the following language, as italicized below, to § 63.7540(a)(10)(i):

As applicable, inspect the burner, and clean or replace any components of the burner as necessary (you may ***perform the burner inspection any time prior to the tune-up or*** delay the burner inspection until the next scheduled unit shutdown).

Attachments

to Comments of CIBO, ACC, and AMP on

2015 Boiler MACT Proposed Reconsideration Rule

CIBO Startup Survey Summary				Cold Startup Data				Warm Start Data				Hot Start Data			
Boiler Type	**Primary Fuel**	**Control**	**Responses Received (# units)**	**Avg hours to come online after first startup fuel ignition**	**Avg time to reach 25% load after coming online**	**Avg time to reach stable operation after 25% load is reached**	**Total time to reach stable operation**	**Avg hours to come online after first startup fuel ignition**	**Avg time to reach 25% load after coming online**	**Avg time to reach stable operation after 25% load is reached**	**Total time to reach stable operation**	**Avg hours to come online after first startup fuel ignition**	**Avg time to reach 25% load after coming online**	**Avg time to reach stable operation after 25% load is reached**	**Total time to reach stable operation**
Circulating FBC	Coal or coal/ biomass	Baghouse	20	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	1-13	2.5-20
Bubbling FBC	Coal	Baghouse	3	6	1	1	8	4	1	1	6	2-4	1	1	4-6
Pulverized Coal	Coal	Baghouse	2	1-6.5	0.1-4	1.4-4	8-9	no response	no response	no response	no response	no response	no response	no response	no response
		ESP	11	5.5-36	0-3	0-5	7-40	5.5-16	0.1-1	0-9	7-18	3.5-9	0.1-1	0-4.7	5.5-11
Stoker or Hybrid Suspension Grate	Coal	Baghouse	7	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
	Biomass	Baghouse	1	24	1	1	26	24	1	1	26	8	1	1	10
	Coal	ESP	6	4.5-10	0-1	0-3	5.5-14	5-8	1	1	7-12	4-7	1	1	6-11
	Biomass	ESP	15	4-24	0.5-8	0.5-20	6-32	4-24	0.5-8	0.5-20	6-32	2-8	0.5-4	0.5-10	4-16
	Biomass	Scrubber	5	4.5-6.5	0.5-1	0.5-2	7-8	4.5-6.5	0.5-1	0.5-2	7-8	4.5-6.5	0.5-1	0.5-2	6.5-7.5
Fuel Cell	Biomass	ESP	2	3-20	2-4	2-26	22-36	3-20	2-4	2-26	22-36	1-8	1-4	1-10	6-16
Liquid	Liquid	Any	4	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

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.

Baghouse on line with Coal 8 Hours

6 Hour operation on Natural Gas To Reach 300° Temp

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.

4.0 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.

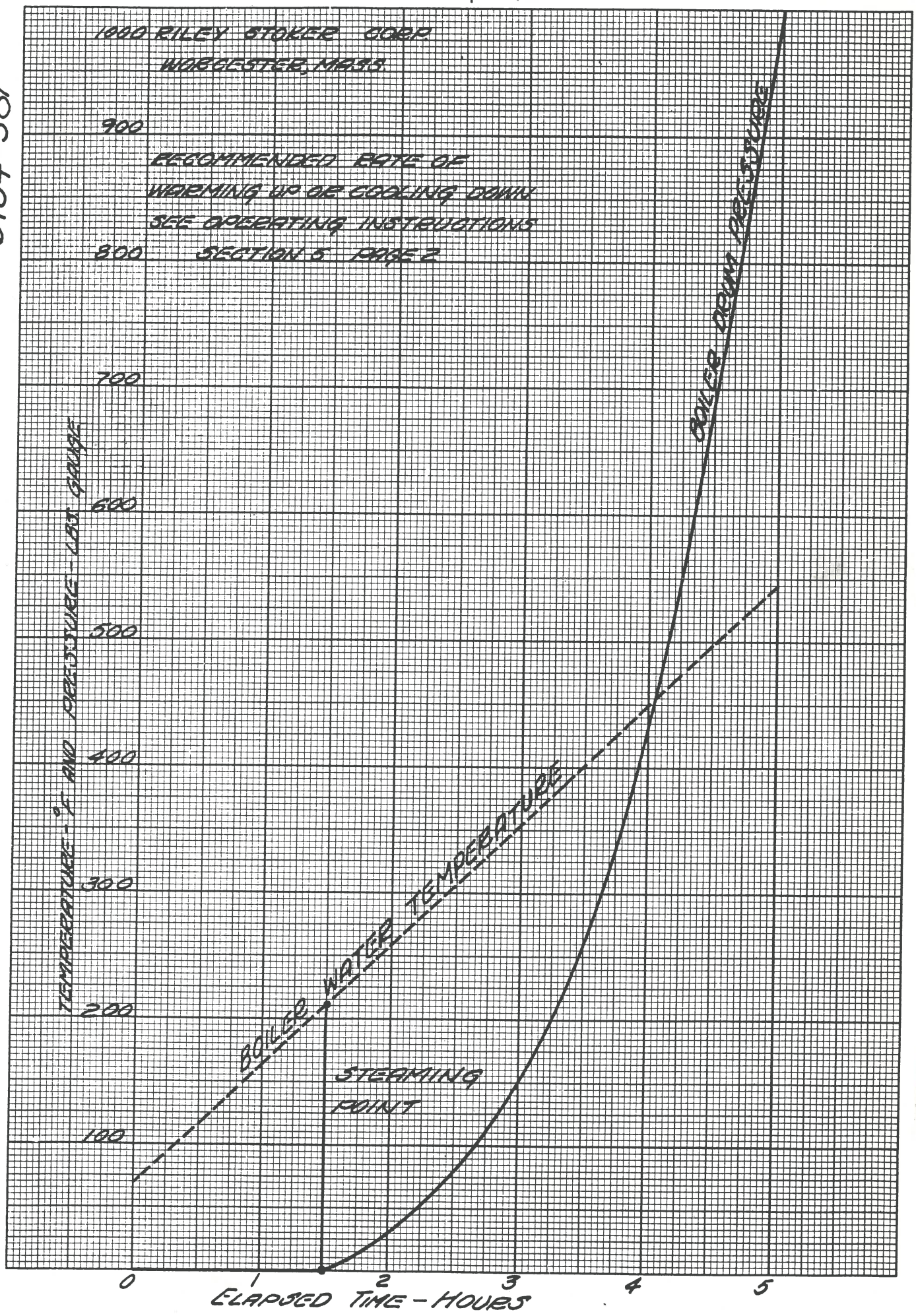
Continuous removal of collected ash and dust is recommended.

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.

FROM #3 BOILER RILEY BOOK 6784-581

6784-581



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 ignitors are required to bring the unit up to pressure.
20. Refer to superate instructions for oil or coal firing.

B) HOT START

1. Follow steps 1 through 10 above.
2. Place all 4 ignitors in service.
3. Refer to separate instructions for oil or coal firing.
4. Boiler should Not increase more than approximately 200 psi per hour.

   Ignitors 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 requirments.

2. Fans should be left running during the non-firing periods to let heat disperse throught 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.

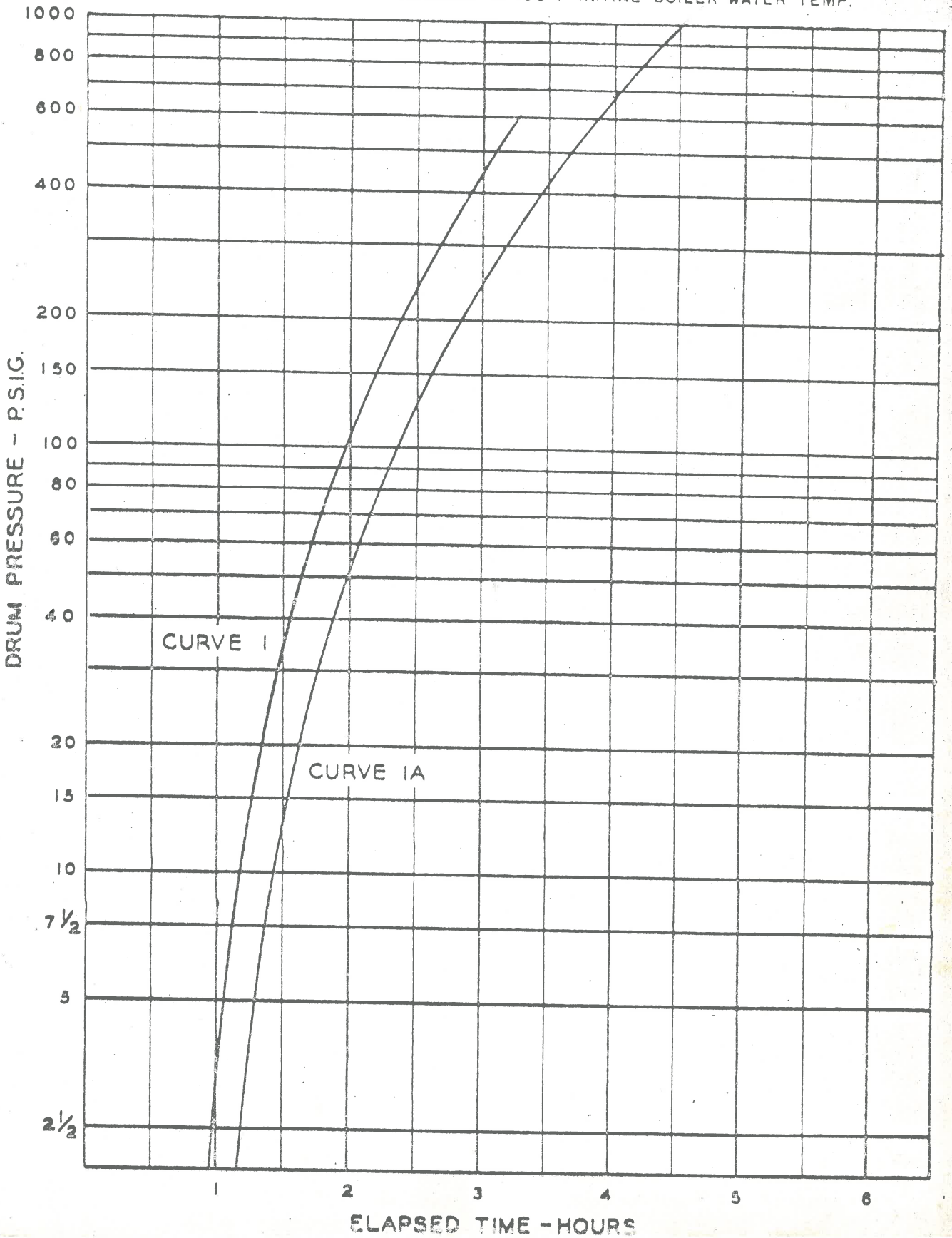
The pressure raising schedule should also take into account the superheated steam temperature rise. The steam temperature should not be allowed to rise to more than 100°F. above the superheated and reheated steam temperature expected in normal operation, and its rise should be moderate. If the temperature 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 1 – BOILERS WITHOUT SUPERHEATERS
120°F PER HOUR TEMP INCREASE @ 100°F INITIAL BOILER WATER TEMP

CURVE 1A – BOILERS WITH SUPERHEATER
100°F PER HOUR TEMP. INCREASE @ 100°F INITIAL BOILER WATER TEMP.



VP

8-1-65

BOILER COLD START-UP

1 Hr

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.

1 Hr To 2 Hr

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 dampers 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 dampers 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.**

4 Hr To 6 Hr

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 ?

BOILER COLD START-UP

2 Hr
To
3 Hr

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

Controls	Scenario	Potential Compliance Issue	Suggested Solution
Any	Startup on clean fuel, engage non-listed controls prior to adding solid fuel.	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.	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)
Wet	Startup on solid fuel	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).	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.

Controls	Scenario	Potential Compliance Issue	Suggested Solution
Dry	Startup on solid fuel	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. Manufacturer 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 **CO 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)	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.

Controls	Scenario	Potential Compliance Issue	Suggested Solution
Any	Unit begins startup, reaches a certain minimum stable load, then there is an equipment problem that results in "failed startup."	All of the above.	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.
Wet	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.	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 know how to set up recordkeeping because 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.	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."

Controls	Scenario	Potential Compliance Issue	Suggested Solution
Dry	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.	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 **24-hour block opacity** or 30-day rolling **CO CEMS limit** if this is not shutdown, depending on compliance margin, type of unit, length of event.	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 **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." 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.
Any	Begin shutdown upon halting fuel feed to the boiler. For some designs, there is still fuel burning in the boiler.	Current definition says "*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.*" 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.	EPA should clarify that fuel being fired in this case means fuel being fed to the combustion unit.

Controls	Scenario	Potential Compliance Issue	Suggested Solution
Wet	More than one unit vents to a wet control device, one unit shuts down, the other unit stays operating.	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.	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.
Any – low load/ standby unit	A unit operates for many hours in standby mode, less than 25% load.	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).	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: • The unit is firing its primary fuel for a period of time adequate to provide stable and non-interrupted fuel flow, stable and controlled air flows, and adequate operating temperatures to allow proper fuel drying and air preheat as applicable. • Emissions controls are in service with operating parameters such as flow rates and temperatures being controlled and stable. • The unit is supplying steam to a common header system or energy user(s) at normal operating conditions including pressure and temperature, and is above the minimum operational stable output flow rate, as applicable to the unit. • For stoker units, when the grate reaches an adequate level of coverage with solid fuel based on visual observation and stability of air, fuel, and steam flow rates.