CIBO Boiler MACT Comments		
6/8/2010		
Draft- for internal discussion only		
Major topic	**Specific Comment**	**Data Needs**
Energy assessment too broad and beyond EPA authority	EPA delving into systems not directly associated with combustion unit- beyond their CAA authority- use legal arguments to object to energy assessments; energy assessment is not a control technology; verify that this is the first attempt by EPA to expand authority into process areas vs the regulated units	
	Investments need to be discretionary by companies; object to mandatory investments for "cost effective" energy efficiency improvements; project justification criteria vary significantly by company, facility, product, etc., and common criteria cannot be established	
	Object to mandatory use of Energy Star practices; those and DOE voluntary programs not tailored for complex facilities	
	Include comments opposing generally output based standards; gain not worth the pain	
	Explain importance of CBI and problems with assessments and any other technical information becoming public knowledge	
	Self assessment is the primary method of assessing complex facilities- those with most knowledge of the systems and equipment	
	Certification by third parties is not a guarantee of a proper assessment and is objectionable	
	Qualified personnel definition relies on specialists who completed DOE or AEE programs or equivalent- revise to also include in-house or third party personnel knowledgeable in the equipment and process involved. Self-assessment should be allowed. Existing third-party certification qualifications and capabilities are not believed to be all-encompassing for all facilities and requiring third party certification would overwhelm certification entities.	
	If they do this, need to limit to only the combustion unit itself, e.g., heat recovery of the combustion flue gas. First recommendation- revise "Boiler system" to read: Boiler system means the boiler and directly associated fuel, combustion air, and flue gas heat recovery components. Fallback recommendation- revise "Boiler system" to read: Boiler system means the boiler and directly associated components, such as feedwater system, combustion air system, fuel system including burners, blowdown system, and combustion control system. Need to be very careful how far we go with this- many systems do not have ability to improve inherent characteristics, such as condensate return.	
	Any resultant projects to improve efficiency under such a program need to be specifically exempted from NSR/PSD/NSPS/any other regulatory initiatives	
	Energy assessment definition is much too broad. Revise the definition to limit scope to the Boiler system as defined per recommendation above.	
	p.111 identifies consideration of energy assessments as a beyond the floor option, but Table 3 lists as a work practice standard- inconsistent and incorrect interpretation since this is not a work practice	
Fuel quality variability	EPA does not have fuel quality data for all top performers, so cannot address fuel quality variability for those units vs emissions data	
	Coal quality variability occurs and that has not been addressed for the top performers- submit Eastman coal Cl data for a unit is a top performer	
	Need to evaluate if all fuel analyses were used for top performing units at a plant site- may have not been tied to specific best performer units- get additional fuel quality data for top performers	
	Comment that fuel quality data for any unit that is a top performer for any pollutant should be used in determining fuel quality variability impact on floors- tie with pooled approach for setting MACT floors?	
	Gas2 has no fuel quality variability factor applied for the floor emissions limits- other gases are extremely diverse and EPA has not addressed this in any way	
	Need to determine how EPA handled fuel quality data since appears they threw out outliers for fuel quality but not emissions data- need explanation from Amanda; can this approach be countered if inappropriate or expanded?	

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Regulation under S112 vs S129 simply based on fuels fired	HW Combustor MACT EEE allows switching between it or otherwise applicable requirements under 112 or 129, so include in S112 and S129 to be able to switch between those applicable requirements	
	This approach eliminates the need for federally enforceable requirement to not burn a particular material	
	Recordkeeping systems can be set up to cover both rule requirements and are submitted to same regulatory authority- all under Title 5 permit	
	Example case- when burning waste water sludge under S129, the water content of the sludge reduces NOx emissions; when not burning sludge, NOx emissions would exceed the CISWI limit	
	Check Def Solid Waste rule for any potential comments for use here	
SSM	EPA statement that they used CEM data from best performing units in establishing standards included S/S periods- unknown how used and very limited at best	
	Emission limits should not be applicable to units during SS periods- propose operating practice during SS to include general content relative to unit specific SS sequences and time limits pending meeting emission limits, e.g., max startup time, sequence of equipment startup actions, conditions when unit is "on line" meeting limits	
	Alcoa data on boiler startup with wet scrubber in operation- higher PM emissions with gas startup vs with coal on line condition	
	EPA cannot assume number of unit startups and frequency (some automatically recycle); typical coal fired can be twice per day for some systems	
	Malfunctions cannot be avoided, even by top performers; Congress realized that and provisions allow for that occurrence; propose use of a malfunction plan that explains potential equipment failures with prescribed troubleshooting and correction actions in order to minimize potential malfunction time- use the plan and actions taken in accordance with the plan as documentation of performing per the general duty clause to minimize emissions	
	Hot standby conditions with intermittent firing is not considered by EPA. Can be any fuel and will not be associated with output since boiler is not on line at the time.	
Operating limits	Setting operating limits at max firing rate is not appropriate for varying firing rate conditions- need to allow for ratio type parameters such as Ca/S ratio, lb/MMacf, etc. Example- excessive sorbent injection can overwhelm the system and waste money. This should be proposed by the source based on what is appropriate for the source, specifically allowed in the rule without alternative monitoring procedures. Include changes to definitions- minimum pressure drop; minimum scrubber effluent pH, minimum scrubber flow rate; minimum sorbent injection rate; minimum voltage or amperage.	
	EPA proposes 12 hour block average for operating parameters based on 4 hour averages during compliance test; recommend using 24 hour rolling average for operating parameters to allow for normal operation fluctuations and slower emissions response to operating parameter changes as well as SS periods if that is included within operating parameter compliance; HON uses 24 hour block average for chemical processes that typically do not vary greatly due to throughput or firing rate as occurs for boilers where the additional latitude of a rolling average is more appropriate; preference- 24 rolling; 24 block; 12 rolling; 12 block. Also a conflict with 7525(d)(4) stating 3 hour block averages- needs to match final table requirement. Include explanation of great diversity of units and operating conditions compared to utility type units.	
	Do not need operating parameters in cases where emissions monitoring will indicate abnormal operating conditions, e.g., PM CEMS	
	HON allows for single point testing and extrapolation with engineering judgment, calculations- use that as a basis	
	4 successive cycles per hour for valid hour of data and one cycle per 15 min- is this a problem relative to missing data? This requirement may get units without CEMS out of CAM. Need methodology to explain how this is to be implemented to avoid automatic deviations upon a problem with operating data.	

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PM CEMS	Conflict between p47 and 253-254- 24 hour vs 30 day rolling average basis; recommend 30 day rolling average basis	
	EPA proposing PM CEMS for all coal, biomass, RO units >250MMBtu/hr units (>400 units in database)- comment to change to allow use of PM CEMS as an option vs opacity/BLD approach- most applicable to wet scrubber applications where scrubber removes PM.	
	Get input from Sick regarding PM CEMS capability to accurately sense PM from the diversity of units involved- is it adequate for all units >250MMB/hr	
	Comment on actual PM CEMS costs, including manual testing required. Annual RATA testing is required per Appendix F. Initial correlation testing per PS-11 requires a minimum of 15 manual reference tests over the full range of PM responses that correspond to normal operatiing conditions for the source and control device and result in widest range of emission concentration. Note that run times <1 hr can be used per PS-11, but that may not be possible with the very low emission limits. However, p.274 (63.7540(a)(9)(iii)) states that response correlation audits must be performed every 3 years- this appears to require the minimum 15 run manual testing over full operating range every three years. This is major cost for emissions testing; EPA must prove 3 year frequency is justified over the apparent initial correlation only with annual RATA in PS-11/App F. This imposes even more additional cost with no additional environmental benefit over use of COMS/BLD and periodic PM testing.	
	In order for PM CEMS to be characterized/correlated over full range, really need PM concentrations higher than or equal to the PM limit, and there is no allowance for this without causing q deviation or violation.	
	No comment re annual M5/5B PM RATA test per PM CEMS Performance Specification requirement and 40CFR60 Appendix F (5.1.1 requires RATA at least once every four calendar quarters)	
	Specifically state that if PM CEMS installed, no COMS or BLD is required	
	Preamble statement re COMS/BLD incorrect- reference Table 4 that BLD or COMS	
	Consider detection limits and accuracy vs proposed limits	
	Check PCA comments on cement MACT	
Compliance timing	Rule uses standard 3 year compliance timing with 1 year extension as appropriate; problems with that timing in not realistic for availability of pollution control equipment; utility MACT will rob personnel and equipment resources; e.g., scrubber project to comply with prior MACT took 4 years to implement (authorization to startup)	
	Many facilities have multiple boilers/process heaters that will all require equipment installation that can only be accomplished with units out of service. Units must be staggered for construction to keep the plant in operation. This greatly extends overall project and compliance timing- over multiple years.	
	Many sources will need to conduct emissions testing to determine actual emissions and controls capability vs final emission limits, requiring time to determine the path forward; in addition, there are a limited number of emissions testing contractors and labs with capability to do proposed testing- this alone will delay compliance for many sources	
	Emission limits will be found unachievable for some equipment, so repowering (e.g. to a CFB boiler) or fuel switching to natural gas might be required; this will entail considerably more time- PULP & Paper Subpart S provides up to 8 years for certain units	
	Extended time for compliance should also be offered for development of new creative technology that can provide superior emissions control performance	
	Some facilities need to obtain capital funding through a formal request process that requires at least 2 years after determining the required approach and cost, which must also follow final rule promulgation	
	Many facilities installed control equipment to meet the prior DDDDD requirements. EPA should grant extended compliance timing (minimum of 5 years from final rule effective date) for those facilities which installed control equipment to meet the prior standard.	
ERT problems	Very difficult and time consuming tool for submission of test data based on ICR testing experience; the problems need to be fixed	

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Electric utility unit definition	Preamble p58 is not correct (not complete) relative to the electric utility unit definition in S112 as identified in the proposed rule definitions	
Surrogates	Generally support use of surrogates for individual HAPs	
	Question to CIBO membership whether TSM alternative to PM limit as a surrogate would be of value; URS will look at potential floor limits for TSM based on 8 metals for both Phase 2 only and combined Phase 1 and 2 compared to Phase 2 10 metals; without affirmative response, CIBO would focus on use of PM and focus HBCA alternative on acid gases only	
	Specifically support filterable PM as the surrogate rather than considering PM2.5 or PM condensable	
Fuel switching	Support EPA position that fuel switching is not a control technology for determining MACT floor	
	Natural gas is not available at all locations; this becomes a major issue for liquid fired units with unachievable MACT Floor limits	
	Use prior comments and arguments	
	Similar comment regarding inappropriateness to force fuel switching between fuel types, e.g., coal type	
	Different fuel qualities may be generally unavailable in some locations so that quality variability within a region needs to be addressed in some manner	
MACT Floor emission limits are so low as to be unachievable	EPA has not adequately demonstrated the correlation between CO as the surrogate for individual organic HAP emissions; how doles really low CO actually impact HAPs	
	It is agreed that high CO levels likely imply organic HAP emissions, but low CO levels (e.g., <100ppm) likely do not have the level of HAP emissions as seen with high CO emissions; need to develop data to support	
Emission limit for D/F	D/F limit comparison to Eastman boiler- low Cl coal, spray dry scrubber with D/F 2x limit	
	EPA apparently applied TEQ calculation to Purdue Univ Boiler 5 data which was already on a TEQ basis, thus lowering the apparent emission rate by 10x or so, giving a false floor calculation; need to evaluate all top performer data to see if this was done to others, recalculate based on correct data	
	Consider whether periodic tune-up could be used as a work practice for D/F instead of emission limits; obtain coal boiler data on tune-up emissions data including CO and D/F	
	Look into boiler/furnace geometry/temperature vs D/F emissions to see if case can be made for need to more investigation/subcategorization based on unit inherent design differences	
	Try to get information from EPRI D/F report regarding emissions and impacts	
Floor setting method- statistical approach	Comment relative to overall statistical approaches; incorrect equations and conversions?	
	UPL vs UCL vs UL vs ?	
	Sample size <30 is statistically not significant, therefore, not appropriate without additional tolerance	
	Dataset skewed due to testing best performers under Phase 2; EPA does not factor to the entire universe of sources	
	Emissions test data from top performers also does not encompass all of the variable conditions of the units and their operations that impact emissions	
	Applying statistical analysis for CO floor based on 3 hour average M10 testing is not applicable to use of CO CEMS compliance over all load conditions	
	EPA apparently did not use the 30 day CEMS testing to set the CO Floor or modify the floor to determine the limit	
	Obtain CEMS data for top performers vs 3 hour test average	
	Recommend minimum of 5 units on which to base floor calculations when <5 are used as 12% of units with data	
	Using 1 or 2 units to set a floor is wholly inappropriate for all units in that subcategory	

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	Comment relative to use of significant figures from stack test results - appears that EPA using 3 or more significant figures, vs 1 or 2 more appropriate- need to find reference for recommended practice and apply to EPA methodology- can it impact floors significantly? Recommend appropriate approach.	
Hg tests for top 12% determination	Verify top performers reported at DL for <DL results and impact on floor calculation	
Additional subcategories	Evaluate potential subcategory split for HCl between bituminous and subbituminous coals and support if justified	
	Need a limited use subcategory for liquid or gas 2 units based on 10% annual capacity factor or 1000 hours/yr as a threshold; impose work practice standard with no emission limits. Especially of value for gas 1 units with liquid backup fuel for use in times other than emergency use.	
Basing floors on emission test data that is DLL	Have any other MACT standard floors been based on data that is DLL?	
	Is there a statistical basis for eliminating DLL data from the floor determination?	
	If legitimate to include, how does that need to be adjusted?	
Units <10MMBtu/hr- work practice only	Similar issues and costs apply to units >10MMBtu/hr	
	Try to leverage from Dc 30MMBtu/hr threshold and apply to MACT	
	How address firetube units that were defined as small in prior rule?	
Gas 1 approach	Support EPA position that emission limits are not an appropriate approach for Gas 1 units and work practice approach is appropriate	
	EPA capital estimate of $14B appears grossly low based on potential control application mentioned in preamble	
	Environmental impact of emissions reductions from gas 1 units is negligible	
	Emissions of fuel based emissions such as Hg and HCl can only be addressed by controls on natural gas suppliers; check cost memo for gas cleanup technology and costs.	
	Not technically or economically feasible to control HAPs from natural gas fired units- leverage from 112d4 wording; so work practice approach is justified; find associated HAP emission reduction quantity in referenced document	
New gas1 sources	Emission limits for new gas 1 units and metal process furnaces should not be promulgated- same arguments as for existing gas1 units	
Gas 2 approach	Extend gas 1 approach to gas 2- not technically or economically feasible to control HAPs from gas2 units	
	Propose alternative approach for other gases meeting certain criteria to be considered as Gas1; e.g., minimum HHV, self-sustaining combustion or minimum supplemental support fuel, percent composition, maximum contaminant levels, etc.	
	Organics- containing gaseous streams should be included as gas1 without specific emission limits- those combustion units are then control devices for other regulated equipment (e.g. HON calls "fuel gas system")	
	Need to explain alternative disposal approaches for gas 2 disposition and overall impact on total emissions (increased use of fossil fuel and potential increased flaring)	

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	Definition for Units designed to burn gas 2- doesn't include deminimis threshold so even token gas 2 use will impose gas 2 emission limits. This will result in decreased use of process offgas & other gases such as LFG, counter to other EPA activities pushing increased use of these fuels with associated env benefits. At minimum, EPA should provide segregated emission limits based on the type of gas 2 fuel. Also- tie in EPA statement in Area Source rule- p.25- "EPA needs to establish emission standards for area source boilers for the following urban HAP in order to meet the section 112(c)(3) 90 percent requirement for these HAP: mercury, arsenic, beryllium, cadmium, lead, chromium, manganese, nickel, POM (as 7-PAH), ethylene dioxide, and PCB. Natural gas fired area source boilers do not emit any of the urban HAP identified above. Therefore, regulation of gas-fired area source boilers is not necessary to meet the 90 percent requirement under section 112(c)(3) for these HAP." Examine gas2 unit emission data vs gas1 to leverage that statement and avoid gas 2 limits.	
	Develop comments regarding lack of data on which to base the gas 2 limits, especially LFG and the actual emissions from LFG combustion compared to gas 1- natural gas combustion and provide example emissions test data for boiler with and without LFG. Since there are many advantages of combusting LFG, it should be included in the scope of Gas 1 with no emissions limits.	
	Get input from the LMOP people/web site/information relative to use of LFG	
New source MACT floor method	Emission limits are unattainable for new sources; vendors will not guarantee that performance	
	EPA needs to identify the best performing similar source in each subcategory as actually attaining all of the proposed emission limits simultaneously in order to use as a floor for all new units; otherwise as it is, the standard is based on a hypothetical uber boiler that does not exist, and is, therefore, not a similar source to new units or existing units	
	Need to expand fuel quality consideration for new source floor to cover range of fuels for new units; investigate actual fuel quality for best source and variability level; craft an approach for an emission level or a percent reduction similar to NSPS for SO2; see also if used in RICE MACT and leverage to these sources. HCl preferentially captured before SO2 so low SO2 emission rates/high removal of SO2 ensures high removal of HCl in wet scrubbing/spray dryer systems (not the case for FBC)	
Alternative existing unit floor basis	Evaluate data and make the case for using an approach for an emission limit OR a percent reduction for HCl and Hg for existing unit subcategories similar to above for new sources	
Health based alternative	Craft support for health based approach based on emissions of HCl, Cl2, HF, HCN; base on facility specific emissions and modeling against reference concentrations provided by EPA using a health Index- refine based on AECOM info	
	Argue against consideration of other sources' emissions when considering impacts from a single source's emissions; residual risk approaches have not extended beyond the single source; also believe very few sources of HCl close to typical Boiler/PH MACT sources other than electric utility plants	
	Base comments to some extent on AECOM work	
	Do informal survey of CIBO members at 6/10 Env Comm mtg to see relative percent of facilities/units that could use HBCA for HCl under prior rule and this rule if limit might be 50% of prior; estimate cost impact	
	Craft legal arguments re support for health based compliance methods	
	Counter statements regarding consideration of other HAP emissions as not applicable	
CO CEMS	Comment on CO CEMS with O2 correction installation (and moisture for some cases) costs and total cost for number of units >100MMBtu/hr; NOx SIP Call units using CO2 diluent need additional O2 monitor with additional cal gases and reconfiguration of CEMS system; must retain CO2 for GHG reporting	
	Recommend an alternative option for using a CO limit as lb/MMBtu for optimum use of existing CEMS equipment	

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	No applicability is mentioned- need to specify only applicable to units with CO limits in Table 1 or 2	
	Number of CO CEMS required to be installed in short period- >1000 units- is availability a problem? If so, allow extended compliance time	
	Rule does not limit CO limit applicability to >50% firing rate as in prior rule- need to evaluate vs 30 day testing and any other CEM data. Area Source rule includes >50% firing rate applicability- need to apply also to major source units.	
	Comment on reality of low CO emission test data relative to method and equipment accuracy- what is real and what is noise?	
Emissions testing	(d) requires 4 hr min test run time for all performance tests; that long is not required for some parameters such as PM; need flexibility to conduct emissions testing in the optimal manner for boiler operation and fuel availability	
	Problem with limited fuel quantity?	
	EPA assumes $44K (EPA Cost Memo) to test all 5 pollutants- worst case fuel mix might be different for each pollutant, so cannot test simultaneously or even within a limited time period for different fuel mixes- this will greatly increase emissions testing time and cost	
	Requirement to be </=75% of limit for 3 consecutive tests to go to 3 year frequency; 75% was not in prior rule- see if any other MACT has this feature; how does detection limit impact this capability? Would operating >90% of MCR during testing allow no discount?	
	Request for staggered testing frequency for similar sources; extend timing to once per permit cycle (5 years); total number of annual tests is staggering- need to reduce required testing	
	Inconsistency in rule language- 63.7550(c)(5) and 63.7555(d)(6) refer to 90% of limit vs 63.7515(b-c) refer to 75%	
	Need to evaluate EPA emission test costs vs actual; compare with prior ICR testing costs- request input from CIBO members	Actual cost of ICR Phase 2 tests with scope of testing
	D/F emission testing not allowed to do triennial testing- this needs to be allowed due to very high cost of testing	
	Use of emissions averaging requires annual emission testing- was this in prior rule? Urge ability to test triennially as with other testing without emissions averaging	
	If compliance is proven with 4 hr minimum test runs and ICR reported testing used to establish the floors was for some shorter or other time, what impact is there on achievability and floor applicability? ICR Phase 2 used 4 hrs for D/F, metals, Hg, PM. Where also using Phase 1 data with shorter times, how addressed in floor setting? Longer times should include more potential operating variability vs shorter times with DL issues.	
	Mercury emissions testing needs to include Method 30B- sorbent trap method	
Emissions averaging	Need to be able to average across all subcategories/ fuels with emission limits for the pollutant to be averaged; 2nd position- average across all solid fuel units; 3rd- average across all units with same emission limit; common stack provisions appear to allow averaging across subcategories	
	Include D/F (unless dropped based on other considerations)	
	Include ability to average CO emissions across all subcategories/fuels with CO limits; use steam output or heat input to calculate flue gas flow rates or use flue gas flow rate monitors to determine on lb/MMBtu basis for averaging. See 40CFR76.11 for example using lb/MMBtu; applicable to units with CEMS.	
	Compliance on monthly basis for first 12 months is unworkable; options- 1) wait until 12 months are available; 2) HON (since 1994)- quarterly balance within 30% (no compliance demonstrated prior to end of 1st quarter), at 12 months balance vs limits; 3) first use 6 months average then average of months available until 12, then rolling; 4) average however many months' data are available in those months	
	Modify the initial demonstration requirement in p243 (e)(1)- that requires demonstration at full heat input that weighted average emissions for all units are below limit; alternative- (reference HON 63.150)- allow initial demonstration for the pollutant to be averaged with units operating at expected typical operating rate for the future year period to determine overall average emission rate vs applicable emission limit	

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	Eliminate 10% discount factor unless extra flexibility above is provided	
	Emissions averaging methodology needs to be modified to allow for use of PM CEMS in the averaging rather than the initial performance test emission rate	
Tune-ups	EPA assumes 1% efficiency improvement with tune-up- that would require average decrease in O2 of 2%, whereas rule p275 requires minimizing CO levels which will generally require increasing excess air and decreasing efficiency (and increasing costs, not decreasing costs as EPA contends), and causing overall increase in all emissions; need to optimize efficiency without focusing only on minimal CO as worded in Tune-up definition on p308- 63.7575	
	Need to consider lowering CO impact on NOx emissions (they will increase)	
	Comment that tune-up to include use of a portable combustion analyzer	
	Comment on items in p275 (10)- that some items are not directly applicable to some units- use as appropriate- particularly for some process heaters;	
	Need to allow scheduling flexibility to allow to be done in conjunction with normal inspections/overhaul schedules- especially important for process heaters that run for extended periods (2-5 years); unit specific demonstration of extended operating times- refer to EPA GHG reporting rule wording; allow flexibility to craft the tune-up or operation check to suit the application	
	Ensure that tune-ups can be done with in-house resources without any certifications	
	Tune-ups generally are not applicable to units that utilize metered fuel/air control systems with continuous excess air (O2) control, where combustion is optimized continuously	
	Tune-up limits adjustments to those in accordance with procedures supplied by the manufacturer or an approved specialist to optimize combustion efficiency. This definition needs to allow for the owner/operator of equipment to be able to establish and conduct appropriate procedures for the equipment and application since those may be site specific and not appropriate for generic manufacturer recommendations. In addition, there is an inherent conflict in the proposed rule- the Tune-up definition refers to optimizing efficiency and the rule requires minimizing CO emissions. Those are not compatible- driving to minimum CO emissions will not optimize efficiency. In fact, in order to minimize CO emissions, it is very likely that excess air will need to be increased considerably higher than that required for optimum combustion efficiency, thus leading to inefficiency and increased costs as well as increases in other emissions.	
	Obtain and include data on example cases with tuning for optimum efficiency vs minimum CO; Hamworthy curve	
Exemptions	Determine if any additional items need to be listed	
	Hot water heater definition is provided for the exemption in 63.7491(d). This should be expanded to include natural gas or distillate fuel oil fired circulating hot water systems used for domestic (e.g., washroom, cafeteria) or space heating purposes no larger than 10MMBtu/hr heat input; this would eliminate the need to spend an inordinate amount of time and effort on units with insignificant emissions	
	Check ASHRAE definitions regarding heating units (90.1?)	
Fuel analysis	Units complying with stack testing burning single fuel are not required to conduct fuel analyses; this needs to be clarified to define a single fuel as including those burning only one type of solid fuel and using gaseous or liquid fuels as startup and/or supplemental fuels; specific clarification required for Eq 7 and Qi explanation. Need to stress inability to obtain "worst case" fuel during emission testing, so need to be able to extrapolate emission test results to the emission limit. See prior MACT rule comments.	
	Cannot accept fuel quality limits being established based on quality during an initial performance test due to inherent variability in fuels; must allow extrapolation from fuel content correlated with emissions test data up to emission limit as an operating limit. Allow use of fuel supplier sampling/analysis as well as onsite sampling, monthly composite sample basis. Tie in with logic relative to percent reduction alternative.	

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	Monthly fuel analysis okay for those using fuel analyses; composite samples okay; cannot require sampling for every supplier of biomass type fuels (see AFPA comments)	
Monitoring	Flow sensor calibration requires at least semiannually- too frequent and not justified. Recalibrations should be done at normal unit overhaul frequency- electronic flow sensors have minimal drift. May not be able to remove from service for calibration without adversely affecting operation.	
	Check pressure tap pluggage daily- extremely onerous and not justified. Gauge calibration with manometer- need to be more flexible; requirements do not reflect common practice.	
	pH meter calibration on at least 2 points every 8 hours of process operation- extremely frequent, not justified. Typical industrial application daily or weekly maximum. Auto calibration ~$30K capital required.	
Technical errors	Reference should be (b)(3)(i) through (iv), not (c)(4)	
	Reference to 63.11202 and 63.11203 are incorrect- should it reference 63.7540?	
	Natural gas definition includes only prior NSPS items, not 2009 NSPS Db and Dc revisions. Need to include the following: "(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 34 and 43 megajoules (MJ) per dry standard cubic meter (910 and 1,150 Btu per dry standard cubic foot)."	
Notifications	Initial notification required within 120 days after 60 days after final rule publication in the Fed Reg- is another initial notice required for units that filed one under the prior Subpart DDDDD? If so, that needs to be clearly specified.	
Recordkeeping	Record of monthly hours of operation by each boiler or process heater applies only to limited use boilers and process heaters. Is this an artifact of the prior rule? Should be retained if limited use units are included in the final rule	
Liquid fired units	Units designed to burn oil def- gaseous fuel boilers and process heaters are limited to 48 hours combined total hours during a calendar year to be excluded as designed to burn oil. This can be read that the 48 hours applies to the total burn time per year, which would be unreasonably limiting. The 48 hour period should be clarified to only apply to the time the unit is operated on oil for testing of oil firing capability, with no limit on legitimate gas curtailment or gas supply emergencies. The 48 hour limit is in the Area Source rule relative only to periodic testing in the Gas-fired boiler definition: “Gas-fired boiler includes any boiler that burns gaseous fuels not combined with any solid fuels, burns liquid fuel only during periods of gas curtailment, gas supply emergencies, or periodic testing on liquid fuel. Periodic testing of liquid fuel shall not exceed a combined total of 48 hours during any calendar year.” (Ref Area Source Rule p.182-63.11237). This would also then be similar to the methodology and 50 hours allowed for non-emergency use in the stationary ICE engine NSPS (40CFR60.4243).	
Table 1 and Table 2 emission limits	Evaluate all floor data and calculations and focus on achieved in practice and achievability, including limits applicability of the units used for the top 12%; variability in all aspects including fuel quality and impact on emissions; units that can or cannot meet all limits, etc.	
	M10 precision and accuracy relative to calibration range used for emissions test data used for top 12% units- are the indicated emission rates within the accuracy range for the method and CEMS used for the test? Impact on floors based on those emission rates?	
	Solid fuel CO limits should all be corrected to 7% O2 similar to D/F limits. Liquid and gas2 D/F limits should be corrected to 3% O2 as listed for CO for those fuels. All emission corrections for a particular fuel need to be corrected to the same O2 level for consistency and to avoid confusion. 7% O2 is generally a more common operating O2 level for solid fuels and 3% is generally a more common operating level for gaseous and liquid fuels. The Area Source rule uses 7% O2 correction for solid fuel and 3% O2 correction for liquid fuel; the major source rule should be similar.	

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	Any emission limits based on fuel quality such as Hg or HCl for distillate fuel oil (No.1 or 2) need to be changed and be based on fuel oil quality or composition only since that is commercial grade heating oil. There is no justification for EPA to impose emissions reductions on ICI users of commercial fuel oil that are not imposed on other uses of the same fuel oil. Any restrictions if proven justified by EPA need to be placed on the suppliers of the fuel oil to meet any limitations in quality without back end cleanup equipment.	
	Opacity limit of 10% on a daily block average may not be adequate to allow operation during SSM periods. What additional latitude can be provided?	
	Include comments opposing generally output based standards; gain not worth the pain	
Alternative Standard	EPA explains alternative approach and floor limits if expanded materials considered as solid wastes, including materials such as secondary wood products combusted on site, coal refuse, and tires processed into TDF, on spec used oil, and all secondary materials used as ingredients managed outside the control of the generator in combustion units.; no petition process offered. This alternative would provide slightly higher Boiler MACT limits and would provide significantly higher CISWI limits for energy recovery units. This appears to be a reasonable approach to accept at this point. Need to look at all pollutants to see if specific problems.	