Final Boiler MACT Rule Requirements Summary

Federal Regulation:

- NESHAP 40 CFR 63 Subpart DDDDD
- Proposed rule published 6/4/2010
- Final rule signed 2/21/2011
- Info at http://epa.gov/airquality/combustion/actions.html

Affected Source:

- The affected source is: (1) the collection of all existing industrial, commercial, or institutional boilers or process heaters within a subcategory located at a major source facility that do not combust solid waste or (2) each new or reconstructed industrial, commercial, or institutional boiler or process heater located at a major source facility that do not combust solid waste, as that term is defined under RCRA.
- A boiler or process heater is new if you commence construction of the boiler or process heater after June 4, 2010, and you meet the applicability criteria at the time you commence construction.
- The affected source does not include boilers and process heaters that are subject to another standard under 40 CFR 63 or a standard established under CAA section 129.

Exemptions:

- An electric utility steam generating unit (note that non-fossil fuel fired utility boilers and utility boilers <25 MW are covered).
- A recovery boiler or furnace covered by 40 CFR 63, subpart MM.
- A boiler or process heater that is used specifically for research and development. This does not include units that provide heat or steam to a process at a research and development facility.
- A hot water heater (≤120 gal, <160 psig pressure, <210°F).
- A refining kettle covered by 40 CFR 63, subpart X.
- An ethylene cracking furnace covered by 40 CFR 63, subpart YY.
- Blast furnace stoves.
- Any boiler or process heater specifically listed as an affected source in another standard(s) under 40 CFR part 63.
- Any boiler or process heater that is used as a control device to comply with another subpart under Part 63, provided that at least 50 percent of the heat input to the boiler is provided by the gas stream that is regulated under another subpart.
- Temporary boilers (onsite less than 180 consecutive days).
- Blast furnace gas fuel-fired boilers and process heaters.

Subcategories:

(a) Pulverized coal/solid fossil fuel units.
(b) Stokers designed to burn coal/solid fossil fuel.
(c) Fluidized bed units designed to burn coal/solid fossil fuel.
(d) Stokers designed to burn biomass/bio-based solid.
(e) Fluidized bed units designed to burn biomass/bio-based solid.
(f) Suspension burners/Dutch Ovens designed to burn biomass/bio-based solid.
(g) Fuel Cells designed to burn biomass/bio-based solid.
(h) Hybrid suspension/grate burners designed to burn biomass/bio-based solid.
(i) Units designed to burn solid fuel.
(j) Units designed to burn liquid fuel.
(k) Units designed to burn liquid fuel in non-continental States or territories.

(l) Units designed to burn natural gas, refinery gas or other gas 1 fuels.
(m) Units designed to burn gas 2 (other) gases.
(n) Metal process furnaces.
(o) Limited-use boilers and process heaters.

- For the fuel based HAP (PM/mercury/HCl), if your new or existing unit combusts at least 10 percent solid fuel on an annual basis, your unit is subject to emission limits that are based on data from all of the solid fuel-fired combustor designs.
- If your new or existing boiler or process heater burns at least 10 percent biomass on an annual average heat input basis, the unit is in one of the biomass subcategories for CO and D/F.
- If your new or existing boiler or process heater burns at least 10 percent coal, on an annual average heat input basis, and less than 10 percent biomass, on an annual average heat input basis, the unit is in one of the coal subcategories for CO and D/F.
- If your new or existing boiler or process heater burns at least 10 percent liquid fuel (such as distillate oil, residual oil), and less than 10 percent solid fuel, on an annual heat input basis, the unit is in the liquid subcategory.
- If your facility is located outside of North America and your new or existing unit combusts at least 10 percent liquid fuel and less than 10 percent solid fuel, your unit is subject to the non-continental liquid fuel emission limits.
- If your unit combusts only natural gas, refinery gas, or equivalent fuel (other gas that qualifies as Gas 1 fuel), with limited exceptions for gas curtailment and emergencies, your unit is subject to a work practice standard that requires an annual tune-up in lieu of emission limits.

Important Definitions:

- Biomass or bio-based solid fuel means any biomass-based solid fuel that is not a solid waste. This includes, but is not limited to, wood residue; wood products (e.g., trees, tree stumps, tree limbs, bark, lumber, sawdust, sander dust, chips, scraps, slabs, millings, and shavings); animal manure, including litter and other bedding materials; vegetative agricultural and silvicultural materials, such as logging residues (slash), nut and grain hulls and chaff (e.g., almond, walnut, peanut, rice, and wheat), bagasse, orchard prunings, corn stalks, coffee bean hulls and grounds. This definition of biomass is not intended to suggest that these materials are or are not solid waste.

- Boiler means an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled. A device combusting solid waste, as defined in §241.3, is not a boiler unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Waste heat boilers are excluded from this definition.

- Coal means all solid fuels classifiable as anthracite, bituminous, sub-bituminous, or lignite by the American Society for Testing and Materials in ASTM D388–05, Standard Classification of Coals by Rank (incorporated by reference, see §63.14), coal refuse, and petroleum coke. For the purposes of this subpart, this definition of "coal" includes synthetic fuels derived from coal for creating useful heat, including but not limited to, solvent-refined coal, coal-oil mixtures, and coal-water mixtures. Coal derived gases are excluded from this definition.

- Electric utility steam generating unit means a fossil fuel-fired combustion unit of more than 25 megawatts that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 megawatts electrical output to any utility power distribution system for sale is considered an electric utility steam generating unit.

- Gaseous fuel includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, refinery gas, and biogas. Blast furnace gas is exempted from this definition.
- Liquid fuel includes, but is not limited to, distillate oil, residual oil, on-spec used oil, and biodiesel.
- Limited-use boiler or process heater means any boiler or process heater that burns any amount of solid, liquid, or gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and has a federally enforceable limit of no more than 876 hours per year of operation.
- Metal process furnaces include natural gas-fired annealing furnaces, preheat furnaces, reheat furnaces, aging furnaces, heat treat furnaces, and homogenizing furnaces.
- Process heater means an enclosed device using controlled flame, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not come into direct contact with process materials. A device combusting solid waste, as defined in §241.3, is not a process heater unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Process heaters do not include units used for comfort heat or space heat, food preparation for on-site consumption, or autoclaves.
- Temporary boiler means any gaseous or liquid fuel boiler that is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A boiler is not a temporary boiler if any one of the following conditions exists:
    - The equipment is attached to a foundation.
    - The boiler or a replacement remains at a location for more than 12 consecutive months. Any temporary boiler that replaces a temporary boiler at a location and performs the same or similar function will be included in calculating the consecutive time period.
    - The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.
    - The equipment is moved from one location to another in an attempt to circumvent the residence time requirements of this definition.

Emissions Limits and Work Practices:

Emission limits were developed for new and existing sources for 15 subcategories, which EPA developed based on unit design.

- Fuel based emission limits for PM, HCl, Hg
- Fuel and boiler design based limits for CO, dioxin/furan

Limits for existing sources are based on top 12% of units for which EPA has data in subcategories with population greater than or equal to 30 units, and top 5 units in subcategories with population less than 30 units. Limits for new sources are based on the top performing unit in each subcategory. Variability was taken into account using a 99 percent upper prediction level (99.9 UPL for CO) and a fuel content variability adjustment for mercury and chloride.

Emissions averaging is allowed for existing affected sources in the same subcategory (solid, liquid, or gas) for PM, HCl, and Hg, but the average emissions have to be within 90 percent of the allowable emissions. Facilities using this approach cannot increase emissions over emission levels achieved upon the effective date of the rule or begin using a less effective control technology than the technology that was in place upon the effective date of the rule.

HAP/Fuel	**Proposal**	**Final**	**Proposal**	**Final**	**Units**	**Output Based (lb/MMBtu steam output)**	
	Existing Boilers		**New Boilers**			**Existing**	**New**
Hg Biomass	0.9	4.6	0.2	3.5	lb/TBtu	4.50E-06	3.40E-06
PM Biomass	0.02	0.039	0.008	0.0011	lb/MMBtu	0.038	0.0011
HCl Biomass	0.006	0.035	0.004	0.0022	lb/MMBtu	0.04	0.0021
Hg Coal	3	4.6	2	3.5	lb/TBtu	4.50E-06	3.40E-06
PM Coal	0.02	0.039	0.001	0.0011	lb/MMBtu	0.038	0.0011
HCl Coal	0.02	0.035	0.00006	0.0022	lb/MMBtu	0.04	0.0021
Hg Oil	4	3.5	0.3	0.21	lb/TBtu	3.30E-06	2.00E-07
Hg Oil non-continental	4	0.78	0.3	0.78	lb/TBtu	8.00E-07	8.00E-07
PM Oil	0.004	0.0075	0.002	0.0013	lb/MMBtu	0.0073	0.001
HCl Oil	0.0009	0.00033	0.0004	0.00033	lb/MMBtu	0.003	0.003
Hg Gas 2	0.2	13	0.2	7.9	lb/TBtu	7.80E-06	2.00E-07
PM Gas 2	0.05	0.043	0.003	0.0067	lb/MMBtu	0.026	0.004
HCl Gas 2	0.000003	0.0017	0.000003	0.0017	lb/MMBtu	0.001	0.003
Or clean gas 2 can opt in to Gas 1 work practice if prior to combustion:	NA	Hg content <40 $\mu g/m^3$	NA	Hg content <40 $\mu g/m^3$	-	NA	NA
		H_2S content <4ppmv		H_2S content <4ppmv	-	NA	NA
CO Biomass stoker	560	490	560	160	ppm at 3%O2	0.35	0.13
CO Biomass FB	250	430	40	260	ppm at 3%O2	0.28	0.18
CO Biomass Dutch/ Suspension	1010	470	1010	470	ppm at 3%O2	0.45	0.45
CO Biomass Fuel Cell	270	690	270	470	ppm at 3%O2	0.34	0.23
CO Biomass Hybrid Suspension/ Grate	NA	3500	NA	1500	ppm at 3%O2	2	0.84
CO Coal pulverized	90	160	90	12	ppm at 3%O2	0.14	0.01
CO Coal stoker	50	270	7	6	ppm at 3%O2	0.25	0.005

HAP/Fuel	Proposal	Final	Proposal	Final	Units	Output Based (lb/MMBtu steam output)	
	Existing Boilers		New Boilers			Existing	New
CO Coal FB	30	82	30	18	ppm at 3%O2	0.08	0.02
CO Oil	1	10	1	3	ppm at 3%O2	0.0083	0.0026
CO Oil non-continental	1	160	1	51	ppm at 3%O2	0.13	0.043
CO Gas2	1	9	1	3	ppm at 3%O2	0.005	0.002
D/F Biomass stoker	0.004	0.005	0.00005	0.005	ng/dscm at 7%O2	4.40E-12	4.40E-12
D/F Biomass FB	0.02	0.02	0.007	0.02	ng/dscm at 7%O2	1.80E-11	1.80E-11
D/F Biomass Dutch/ Suspension	0.03	0.2	0.03	0.2	ng/dscm at 7%O2	1.80E-10	1.80E-10
D/F Biomass Fuel Cell	0.02	4	0.0005	0.003	ng/dscm at 7%O2	3.50E-09	2.86E-12
D/F Biomass Hybrid Suspension/Grate	NA	0.2	NA	0.2	ng/dscm at 7%O2	1.80E-10	1.80E-10
D/F Coal pulverized	0.004	0.004	0.002	0.003	ng/dscm at 7%O2	3.70E-12	2.80E-12
D/F Coal stoker	0.003	0.003	0.003	0.003	ng/dscm at 7%O2	2.80E-12	2.80E-12
D/F Coal FB	0.002	0.002	0.00003	0.002	ng/dscm at 7%O2	1.80E-12	1.80E-12
D/F Oil	0.002	4	0.002	0.002	ng/dscm at 7%O2	9.20E-09	4.60E-12
D/F Gas2	0.009	0.08	0.009	0.08	ng/dscm at 7%O2	3.90E-11	4.10E-12

A work practice applies during periods of startup and shutdown. You must follow the manufacturer's recommended procedures for minimizing periods of startup and shutdown. The emissions and operating limits apply during malfunction periods. You may use the affirmative defense provision to justify excess emissions during malfunction periods that meet the 9 criteria in the rule.

Limited-use boilers and process heaters must complete a biennial tune-up. They are not subject to the emission limits, the annual tune-up requirement, or the operating limits. Major sources that have limited-use boilers and process heaters must complete an energy assessment only if the source has other existing boilers subject to this subpart that are not limited-use boilers.

Work practices are required for all new and existing units less than 10 MMBtu/hr in size (biennial tune-up) and for all natural gas/refinery gas units and metal process furnace units (annual tune-up for gas units $\geq$10 MMBtu/hr). If the unit is not operating on the required date of the tune-up, it must be conducted within one week of startup.

1. Inspect the burner, and clean or replace any components of the burner as necessary (you may delay burner inspection until next scheduled unit shutdown, but must inspect burner at least once per 36 months),
2. Inspect the flame pattern, as applicable, and make any adjustments to the burner necessary to optimize the flame pattern consistent with the manufacturer's specifications,
3. Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly,
4. Optimize total emissions of CO consistent with the manufacturer's specifications,
5. Measure the concentrations in the effluent stream of CO in ppmv and O_2 in percent, before and after the adjustments are made,
6. Maintain a report containing the concentrations of CO in the effluent stream in ppmv, and oxygen in percent, measured before and after the adjustments of the boiler, a description of any corrective actions taken as a part of the combustion adjustment, and the type and amount of fuel used over the 12 months prior to the annual adjustment if the unit is capable of burning more than one fuel.

As provided in 63.6(g), EPA may approve use of an alternative to the work practice standards in the rule.

A beyond the floor requirement is also included for all existing major source facilities having affected boilers or process heaters that would require the performance of a one-time energy assessment by qualified personnel on the affected boilers and energy use system to identify any cost-effective energy conservation measures (cost effective means items having a payback period of 2 years or less). The facility must also implement an energy management program.

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

- Energy assessment for facilities with affected boilers and process heaters using less than 0.3 trillion Btu per year heat input will be one day in length maximum. The boiler system and energy use system accounting for at least 50 percent of the energy output will be evaluated to identify energy savings opportunities, within the limit of performing a one-day energy assessment.

- The Energy assessment for facilities with affected boilers and process heaters using 0.3 to 1.0 trillion Btu per year will be 3 days in length maximum. The boiler system and any energy use system accounting for at least 33 percent of the energy output will be evaluated to identify energy savings opportunities, within the limit of performing a 3-day energy assessment.

- In the Energy assessment for facilities with affected boilers and process heaters using greater than 1.0 trillion Btu per year, the boiler system and any energy use system accounting for at least 20 percent of the energy output will be evaluated to identify energy savings opportunities.

Energy management program means the set of practices and procedures designed to manage energy use that are demonstrated by the facility's energy policies, a facility energy manager and other staffing responsibilities, energy performance measurement and tracking methods, an energy saving goal, action plans, operating procedures, internal reporting requirements, and periodic review intervals used at the facility.

Testing Requirements for Units with Emission Limits:

Affected sources must demonstrate initial compliance within 180 days of the compliance date or within 180 days of startup. Testing must be conducted during representative operating load conditions. Future operating load must not exceed 110 percent of load during testing. Sources that cease burning solid waste and become regulated under Boiler MACT must demonstrate initial compliance within 60 days of the effective date of the waste to fuel switch.

(1) Conduct initial and annual stack tests to determine compliance with the PM emission limits using EPA Method 5 or 17. (Note that if a unit is >250 MMBtu and burns solid fuel or residual oil, PM CEMS are required, which require extensive calibration testing.)
(2) Conduct initial and annual stack tests to determine compliance with the mercury emission limits using EPA method 29, 101A, or ASTM-D6784-02 (Ontario Hydro Method).
(3) Conduct initial and annual stack tests to determine compliance with the HCl emission limits using EPA Method 26A or EPA Method 26 (if no entrained water droplets in the sample).
(4) Use EPA Method 19 to convert measured concentration values to pound per million Btu values.
(5) Conduct initial and annual test to determine compliance with the CO emission limits using EPA Method 10.
(6) Conduct initial test to determine compliance with the D/F emission limits using EPA Method 23.

- Conduct HCl and Hg performance tests while operating at representative operating load and burning the fuel mixture that has the highest content of Hg and chlorine (may have to do 2 tests). Develop maximum Cl and Hg fuel input limits based on fuel sampling and operating parameter monitoring ranges based on initial performance testing. If you are only burning one type of fuel, you are exempt from fuel sampling requirements.

- You can conduct performance stack tests less often for a given pollutant if your performance stack tests for the pollutant for at least 2 consecutive years show that your emissions are at or below 75 percent of the emission limit, and if there are no changes in the operation of the affected source or air pollution control equipment that could increase emissions. In this case, you can conduct a performance test every 3 years, but no more than 37 months after the last performance test. If a performance test shows emissions greater than 75 percent of the applicable emission limit, then you revert to annual performance testing for the next 2 years.

- The reduced testing frequency cannot be used if you are using emissions averaging.

- If you are demonstrating compliance using fuel analysis for mercury or HCl, fuel analysis must be performed monthly and before burning a new type of fuel. You are not required to conduct fuel analysis for fuels used only for startup, shutdown, or transient flame stability purposes. If 12 consecutive monthly fuel analyses demonstrate compliance, you may request decreased fuel analysis frequency by applying to the EPA Administrator for approval of alternative monitoring under §63.8(f).

- If you are demonstrating that a gaseous fuel meets the H_2S and Hg specifications of an "other gas 1" fuel, you must conduct an initial fuel specification analysis. If your gas could vary above the specifications, you must conduct monthly testing and maintain records.

- Report results of all stack tests and fuel analyses within 60 days of completion. Stack test reports must verify that operating limits have not changed or provide documentation of revised operating limits. Results must be reported to the EPA's online ERT.

Use of Output Based Limits and Emission Credits from Energy Conservation Measures

You can comply with the output based emission limits and take credit for implementing energy conservation measures identified in the energy assessment. To use this approach, you must establish an emissions benchmark, calculate and document the emission credits, develop an implementation plan, comply with the general reporting requirements, and apply the following emission credit procedures:

- Establish a benchmark for each affected boiler in terms of trillion Btu per year heat input. The benchmark is established for the one-year period prior to the energy demand reduction.
- Determine the starting point from which to measure progress. Inventory all fuel purchased and generated onsite.
- Document all uses of energy from the affected boiler.
- Collect data to normalize the benchmark to current operations.
- Emissions credits can be generated if the energy conservation measures were implemented after January 14, 2011 and if sufficient information is available to determine the value of the credits. Boilers that are shutdown cannot be used to generate credits.
- Credits are generated by the difference between the benchmark that is established for each boiler and the actual energy demand reductions. The credit is equal to the energy input savings divided by the baseline energy input.
- Adjusted emission level for each boiler = (measured emissions, lb/MMBtu)x(1-credit)

Operating Limits:

Control Device	Operating Limits
Wet scrubber control	Minimum 12-hour average pressure drop and liquid flow is 90 percent of performance test average (3-hour average for sources using emissions averaging); For HCl control, minimum 12-hour average pH is 90 percent of performance test average.
Fabric filter control (for sources not using PM CEMS)	Operate bag leak detection system and fabric filter such that alarms are less than 5% of the operating time during a semi-annual period, initiate corrective action within 1 hour of an alarm; OR Maintain daily block average opacity <10%
ESP (dry control system, sources not using PM CEMS)	Maintain daily block average opacity <10%
ESP (followed by wet scrubber, sources not using PM CEMS)	Minimum 12-hour average voltage and current or 12-hour average minimum power is 90 percent of performance test average
Dry scrubber	Minimum 12-hour average sorbent injection rate is 90 percent of performance test average (adjusted for load)
Carbon injection	Minimum 12-hour average sorbent injection rate is 90 percent of performance test average (adjusted for load)
Other dry control system (sources not using PM CEMS)	Maintain daily block average opacity <10%
Operating load (if demonstrating compliance using stack testing)	Maintain 12-hour average operating load at or below 110 percent of load during performance test

Control Device	Operating Limits
Oxygen concentration (for boilers and process heaters that are subject to a CO and a dioxin/furan emission limit)	Measure the oxygen concentration in the flue gas during the initial CO and dioxin/furan performance test. The lowest hourly average oxygen concentration during the most recent performance test is your operating limit, and your unit must operate at or above your operating limit on a 12-hour average basis.
Fuel analysis option	Maintain fuel type or fuel mixture such that the calculated emission rate is less than the applicable emission limit.

For units combusting coal, biomass, or residual oil with heat input capacities of 250 MMBtu/hr or greater, PM CEMS must be installed and operated such that PM levels (30-day rolling average) are maintained below the applicable PM limit. If PM CEMS are used, no PM pollution control device or opacity operating parameter limits apply.

Operating above established maximum or below established minimum operating limits is a deviation except during performance tests conducted to determine compliance with the emission limits or to establish new operating limits.

Development of Plans:

- Site specific monitoring plan
- Site specific test plan
- Site specific fuel analysis plan
- Emissions averaging plan (if applicable)
- Output based limits emission credits implementation plan (if applicable)

Continuous Compliance/Monitoring Requirements:

- Continuously monitor control device parameters for which operating limits have been developed, 12-hour block averages.
- For boilers subject to CO and D/F limits, must install an O2 CEMS, 12-hour averaging period for operating limit.
- For solid fuel or residual oil-fired boilers with dry control devices not using PM CEMS or bag leak detectors, install COMS and maintain opacity <10%, daily block average.
- If burning multiple fuels, maintain fuel mixture Hg and Cl content at or below the maximum fuel input levels established during initial performance test.
- For boilers $\geq$250 MMBtu/hr burning coal, biomass, or residual oil, must install a PM CEMS, 30-day averaging period.
- Follow applicable plans, including QA requirements for monitoring systems.

Notifications:

- Initial Notification no later than 120 calendar days after you become subject to the rule (even if you submitted one under the 2004 rule);
- Notification of intent to conduct performance test at least 60 days prior to any compliance demonstration;
- Notification of compliance status within 60 days of completion of any compliance demonstration;

- For natural gas fired units that intend to fire an alternative fuel during a curtailment period or supply interruption, a Notification of alternative fuel use within 48 hours of the declaration of a period of natural gas curtailment of supply interruption.
- For boilers that choose to commence or recommence burning solid waste, must provide 30 day notice.
- If you intend to switch fuels and change subcategories, provide 30 days notice.

Recordkeeping Requirements:

- Records demonstrating compliance with above requirements.
- Records documenting malfunctions and deviations.
- Hours of operation for each limited use unit.
- Monthly fuel use records.
- Documentation that you are not burning solid waste.
- Owners or operators of sources with units with heat input capacity of less than 10 MMBtu/hr, units combusting natural gas or other clean gas, metal process furnaces, and limited use units must keep records of the dates and the results of each required boiler tune-up.