

United States Air Force
National Emission Standards for Hazardous Air
Pollutants for Major Sources:
Industrial, Commercial, and Institutional Boilers
Guide

40 CFR Part 63 Subpart DDDDD



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USAF BOILER NESHAP GUIDE FOR MAJOR SOURCES

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Based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

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EXECUTIVE SUMMARY

The purpose of this document is to provide certain United States Air Force (USAF) personnel (technicians, boiler operators, etc.) with a basic understanding of key requirements for complying with 40 CFR 63, Subpart DDDDD, *National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers* (commonly referred to as “Boiler MACT” or Subpart DDDDD). Hazardous Air Pollutants (HAPs), are toxic air pollutants suspected to cause cancer or other serious health effects. A “Major Source” HAP facility emits 10 or more tons per year of any single air toxic or 25 or more tons per year of any combination of air toxics.

The Clean Air Act (CAA) requires the United States Environmental Protection Agency (EPA) to regulate toxic air pollutants. Boilers and process heaters use controlled flame combustion to burn fuels such as gas, coal, oil, and biomass to produce steam which is then used for energy or heat. The combustion of these fuels result in emissions of various HAPs.

Subpart DDDDD applies to boilers and process heaters located at commercial, industrial, and institutional Major Source facilities that burn gas, coal, oil, biomass, or other solid and liquid non-waste materials. The Rule does NOT apply to residential boilers, electric boilers, waste heat boilers, temporary boilers, boilers used for research and development, boilers that burn only gaseous fuels or any solid waste, boilers used as control devices for other standards, or boilers that are subject to another subpart of 40 CFR 63.

Compliance requirements depend on the type of fuel burned in the boiler or process heater, whether the boiler or process heater is new/reconstructed or existing, and on the size and combustion design of the boiler or process heater. A “new” boiler was built or reconstructed after 4 June 2010. Boilers and process heaters are categorized as having a designed heat input capacity of 10 million British thermal units per hour (MMBtu/hr) or greater or having a designed heat input capacity less than 10 MMBtu/hr. Fuel Subcategories include Gaseous fuel (Gas 1 and Gas 2), Solid Fuel (Coal and Biomass), and Liquid fuel (Heavy and Light).

- Gas 1 fuel is natural gas, refinery gas, and/or “other Gas 1 fuels” (not natural gas or refinery gas, but does not exceed a maximum concentration of 40 micrograms/cubic meters of mercury). “Gas 2” is any gaseous fuel that is not a “Gas 1” fuel.
- Combustion design type subcategories, such as stoker and Dutch Oven, apply to boilers and process heaters with a designed heat input capacity of 10 MMBtu/hr that burn solid (coal and biomass) fuels.
- There is a “noncontinental” liquid fuel subcategory for boilers and process heaters located in the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.
- Reduced tune-up frequencies were established for limited-use boilers (boilers that have a federally enforceable average annual capacity factor of no more than 10 percent) and boilers with an oxygen trim system that maintains an optimum air-to-fuel ratio.

Subpart DDDDD requirements can be as straight-forward as periodic tune-ups, which is the only requirement for new boilers and process heaters smaller than 10 MMBtu/hr and boilers that burn Gas 1. Existing boilers and process heaters are also subject to a one-time energy assessment. The requirements can also be as complex as complying with emission and operating limits to control emissions of Filterable Particulate Matter (PM), Carbon Monoxide (CO), Hydrogen Chloride (HCl), and/or Mercury (Hg) through performance (stack) testing and/or fuel analysis (boilers 10 MMBtu/hr or larger that burn solid fuel, liquid fuel, or certain gaseous fuels).

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1 INTRODUCTION

The United States Environmental Protection Agency (EPA) was mandated by Section 112 of the Clean Air Act (CAA) to develop National Emission Standards for Sources of Hazardous Air Pollutants (NESHAPs) for specific industries, such as industrial, commercial, and institutional boilers. The regulations stipulate compliance requirements such as work practice standards (i.e., tune-ups, energy assessments) and/or emission and operation limits, based on the boiler's size, construction/reconstruction date, and fuel type

1.1 Purpose

The purpose of this document is to provide certain United States Air Force (USAF) personnel (technicians, boiler operators, etc.) with a basic understanding of key requirements for complying with the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Industrial, Commercial, and Institutional Boilers located at Major Sources [40 Code of Federal Regulations (CFR) Part 63, Subpart DDDDD], also known as the Boiler Maximum Achievable Control Technology (Boiler MACT) Rule or Subpart DDDDD. The intent of Boiler MACT is to substantially reduce emissions of toxic air pollutants from industrial, commercial, and institutional boilers and process heaters.

This Guide is intended to be used solely as general guidance for navigating the complexities of Boiler MACT and highlights important provisions in regards to the subject matter. Due to the intricacy of Boiler MACT and related regulations, the guidance cannot be expected to encompass every type of compliance situation. Furthermore, the information conveyed in this Guide is dynamic and subject to change depending on rules promulgated by the United States Environmental Protection Agency (EPA). The CFR and the Federal Register (FR) should be consulted for updates on 40 CFR 63, Subpart DDDDD due to the frequent revisions of the rule. Citations to the regulatory text in the CFR are used throughout this Guide for reference and to assist the user in finding the appropriate regulatory sections. This guidance is not a law or regulation, nor is it intended to replace or revise any underlying regulatory requirements, including federal, state, or local regulations. The information presented here is not legal advice and the Guide must not be used as a legal resource. Although all reasonable efforts were made to ensure that information provided is accurate at the time written, no representations or warranties, implied or otherwise, can be made that this Guide is completely free from errors or omissions. Subpart DDDDD has been amended and clarified numerous times due to technical and drafting errors and as a result of input from the regulated community and court rulings; therefore, the rule itself is likely to contain errors.

Any questions concerning this document, and/or requests for additional information pertaining to Boiler MACT, should be directed to the Air Quality Subject Matter Expert; AFCEC Compliance Technical Support Branch (AFCEC/CZTQ); 250 Donald Goodrich Drive; Building #1650; Lackland AFB, TX 78226.

1.2 What is Boiler MACT?

The Clean Air Act (CAA) requires EPA to develop and enforce regulations to protect the public from exposure to airborne contaminants that are known to be hazardous to human health. In accordance with Section 112 of the CAA, EPA established NESHAPs for specific industrial sectors. The standards are for identified toxic air pollutants (air toxics) not covered by National Ambient Air Quality Standards (NAAQS). Toxic air pollutants, also referred to as Hazardous Air Pollutants (HAPs), are air-borne contaminants that are known or suspected to cause serious, irreversible, or incapacitating illness.

Boilers and process heaters are a common source of air pollutants and are typically located at manufacturing facilities, refineries, hotels, hospitals, and universities. Boilers and process heaters burn gas, oil, coal, wood, or other fuels to produce steam, which is then used to produce hot water, heat, or electricity for those facilities. The combustion of these fuels result in emissions of various HAPs. The HAP emissions from individual boilers and process heaters are normally low, but the total emissions from those sources are significant. These HAP emissions are known or suspected to cause damage of the immune system, as well as neurological, reproductive, developmental, respiratory, and other health problems. Vulnerable groups, such as children and elderly, are particularly at risk. EPA is charged to promulgate standards which provide an ample margin of safety to protect public health.

To protect human health and the environment, the EPA promulgated NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters, commonly referred to as Boiler MACT or Subpart DDDDD, to regulate emissions of HAPs emitted from those units (40 CFR Part 63, Subpart DDDDD). Boiler MACT applies to industrial, commercial, and institutional boilers and process heaters that burn coal, biomass (i.e., wood products), liquid fuels, natural gas, refinery gas, and other gaseous fuels located at major sources of HAPs. Major source facilities are those that have the potential-to-emit 10 or more tons per year (tpy) of any single HAP or 25 tpy or more of any combination of HAPs.

As the title of the rule implies, affected sources must install and operate MACT to limit HAPs emissions. MACT is a level of control that was introduced by Title III of the 1990 Clean Air Act Amendments to expedite the development of standards to reduce HAPs. To determine what constitutes MACT, the EPA evaluates similar best-performing sources and industries (in this case, commercial, industrial, and institutional boilers and process heaters) to set a baseline known as the “MACT floor”. The EPA can establish more stringent standards than the MACT floor when deemed appropriate while taking into consideration economics, environment, and public health. Boiler MACT requires each affected boiler and process heater to implement those standards on an initial and continuous basis. Control Technology is commonly perceived to refer only to air pollution control devices (filters, scrubbers, etc.); however, that is not accurate.

Control Technology also includes work practices (tune-ups, energy assessments, etc.), equipment modifications, fuel specifications, and other standards to reduce or eliminate pollutant emissions. Typically, MACT includes several options for emission control which may involve extensive testing, operating, monitoring, record keeping, and reporting requirements. In this case, for boilers and process heaters, work practice standards such as periodic and thorough tune-ups are considered to be sufficient to control HAP emissions for smaller units and units that burn natural or refined gas. Yet more stringent work practices, controls, and requirements apply to larger boilers and process heaters which combust liquid, solid, and some types of gaseous fuels. Emission reduction requirements may include:

- Work practices such as tune-ups, inspections, assessments, and operation methods.
- Process adjustments, equipment modification or replacement, including fuel switching.
- Capture and treatment of pollutants emitted.
- Emission or operation monitoring devices and/or systems.
- Extensive record keeping and reporting requirements to ensure requirements are being met.

Boilers and process heaters located at Area Sources (sources that emit less than 10 tons of an individual HAP and less than 25 tons of all HAPs combined) also face regulations for HAPs, but for the most part, those units are required to meet a less stringent standard, referred to as Generally Available Control Technology (GACT). The regulations for those units are located in another NESHAP Subpart (40 CFR Part 63 Subpart JJJJJ).

Depending on the fuel burned, boilers and process heaters can emit a wide variety of HAPs, including arsenic, formaldehyde, lead, benzene, chlorine, mercury, and cadmium. Instead of establishing emission limits for each and every regulated HAP, which would be a burden for both facilities and regulators, the EPA frequently uses surrogates. The surrogate pollutants have similar post-combustion characteristics to the original HAP(s) and often can be controlled with similar techniques. For Boiler MACT, the HAPs were grouped into four common categories: mercury, non-mercury metallic HAP, inorganic HAP, and organic HAP. Next, regulated HAPs were evaluated to identify which could be used as surrogates for each category. Additionally, the EPA recognized that Particulate Matter (PM) would be an appropriate surrogate for metallic HAP in some situations, but not for others. Therefore, Boiler MACT established an alternative emission limit for PM using selected metals (i.e., arsenic, beryllium, cadmium, chromium, lead, manganese, nickel and selenium). After considerable debate, research, and evaluation, the EPA set Boiler MACT emission limits and/or work practice standards for the following pollutants (or surrogates):

- Mercury (Hg) - No surrogate.
- Non-mercury metallic HAP - Filterable Particulate Matter (PM) or Total Select Metals (TSM).
- Inorganic HAP - Hydrogen Chloride (HCl) as a surrogate for acid gas HAPs.

- Organic HAP - Carbon Monoxide (CO).
- Dioxin/Furan - No surrogate, but it was determined that levels were too low for reliable measurement. Work practices, such as periodic tune-ups, were found to be sufficient for control of these HAPs.

1.3 Legislative History

Section 112 of the CAA requires EPA to establish NESHAPs for both major and area sources of HAPs. Boiler MACT was originally issued by the EPA in 2004, but experienced a turbulent legislative history since initially promulgated. The rule has gone through several modifications, stays, and deadline extensions. As a result, Boiler MACT is one of the most complex air quality regulations issued by the EPA. A timeline of the legislative history is provided below.

- January 2003: Original rule proposed
- September 2004: Original rule issued
- June 2007: Rule vacated by D.C. Circuit Court
- June 2010: Revised Boiler (Subpart DDDDD and Subpart JJJJJ) rules proposed
- March 2011: EPA publishes “Final” MACT/GACT rules
- May 2011: EPA issues reconsideration notice to stay Boiler MACT indefinitely
- December 2011: EPA proposes additional changes to Subpart DDDDD and Subpart JJJJJ
- January 2012: D.C. Circuit Court declares the EPA’s indefinite stay of Boiler MACT a violation of the CAA (maximum of 90 days is allowed for a stay), making the Boiler MACT rule effective immediately
- January/February 2013: Final rules published
- 21 January 2015: Proposed amendments, changes, and corrections published
- 20 November 2015: Final rule published (80 FR 72790)

Court decisions, legislation, and other regulatory actions with the potential to impact Boiler MACT are either already in progress or are anticipated, creating challenges for both the EPA and the regulated community. As a result, keeping up with the rapidly shifting boiler and process heater regulations is an unrelenting task for affected facilities. The CFR and the FR should be frequently consulted for updates on Boiler MACT due to the continually evolving nature of the regulations.

1.4 Guide Instructions

This Guide will take the user step-by-step through the process of determining applicability, initial compliance requirements, and continuing compliance requirements. The Guide first assists the user in determining whether or not Boiler MACT is applicable to the boiler or process heater in question. If Boiler MACT is applicable, then the boiler or process heater needs to be

evaluated to determine the appropriate subcategory for the unit. The boiler or process heater subcategory dictates which procedures are necessary for compliance with the rule. After the compliance requirements are ascertained, then steps must be taken to fulfill those requirements. The compliance requirements are divided into tasks within this Guide to facilitate understanding of the procedures and their associated order.

NOTE: This Guide will make references to “Administrator”, “appropriate Administrator”, or “delegated authority”, which is meant to include the EPA Administrator and/or the state, local, or tribal agency, whichever is applicable. In many cases, the EPA delegated implementation and enforcement authority of Boiler MACT to the state, regional, local, or tribal agency. The agency becomes the primary authority for the delegated standard, but the EPA retains concurrent authority. In general, the delegated state, local, or tribal agency is responsible for implementation, enforcement, compliance assistance, and approval of minor changes to testing, monitoring, and recordkeeping methods. However, EPA retains oversight of Boiler MACT and can take enforcement actions as appropriate. To ensure national consistency with the rule, some authorities cannot be delegated and are retained by the EPA, including approval of major changes. To determine if the EPA delegated authority for Boiler MACT to an agency where the boiler is located, contact the applicable EPA Regional Office or refer to 40 CFR §63.99.

1.5 Determining Applicability

NOTE: A questionnaire for assisting with determining whether or not subpart DDDDD applies to the boiler or process heater is included in Appendix A of this Guide.

Subpart DDDDD applies to new, reconstructed, and existing industrial, commercial, or institutional boilers or process heaters which are located at, or are part of, a facility that is classified as a major source of HAPs. The rule does not apply to residential boilers and process heaters. The rule applies to boilers and process heaters that combust coal, biomass, liquid fuel, or gas, but does NOT apply to boilers and process heaters that burn ANY solid waste. Each of the following steps are necessary to determine applicability of Subpart DDDDD to the boiler.

Step One - The first step to determining applicability is to ascertain whether or not the facility has a boiler or process heater as defined in Boiler MACT.

The definitions of a boiler and process heater per §63.7575 of Subpart DDDDD are as follows:

- A boiler is an enclosed device that uses controlled flame combustion to burn coal and other substances such as oil or biomass to produce steam or hot water, which is then used for energy or heat. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled.
- A process heater is a device that transfers heat indirectly to a process material or to a heat transfer material for use in a process unit instead of generating steam. Combustion gases from process heaters do not come into direct contact with process materials. Process heaters do not include units used for comfort heat or space heat, food preparation for on-site consumption, or autoclaves.

IMPORTANT NOTE: Waste heat boilers and waste process heaters are NOT subject to Boiler MACT. The definition of a waste heat boiler/process heater, per the EPA, is as follows:

- Waste heat boiler and process heaters means a device that recovers normally unused energy (i.e., hot exhaust gas) and converts it to usable heat. Waste heat boilers are also referred to as heat recovery steam generators. Waste heat boilers are heat exchangers generating steam from incoming hot exhaust gas from an industrial (e.g., thermal oxidizer, kiln, and furnace) or power (e.g., combustion turbine, engine) equipment. Duct burners are sometimes used to increase the temperature of the incoming hot exhaust gas. (§63.7575)

Step Two – Determine whether or not the boiler or process heater burns ANY solid waste.

Boiler MACT applies to boilers and process heaters that combust coal, biomass, liquid fuel, or gas, but does NOT apply to boilers and process heaters that burn ANY solid waste. If a boiler or

process heater is firing solid waste, then it is required to meet the more stringent standards for Commercial/Industrial Solid Waste Incinerators (CISWI), rather than Boiler MACT. Although USAF installations typically burn traditional fuels in their boilers (gas, oil, or coal), this topic is addressed in this Guide due to the increased use of non-traditional fuels, such as certain biomass materials. Differentiation between solid waste and a “traditional fuel” or “non-traditional fuel” is particularly vital to applicability of Boiler MACT, so it is important to verify whether or not the fuel combusted in the boiler or process heater is solid waste. Definitions of the types of fuels are provided below.

- Traditional “non-waste” fuels include conventional fossil fuels such as coal, oil, and natural gas, as well as fossil fuel derivatives such as refinery gas and bituminous coke. The definition of traditional fuels was also expanded to include non-conventional or “alternative” fuels such as ethanol (produced from corn and other crops) and biodiesel (derived from vegetable oils and animal fats). Essentially, traditional fuels encompass two categories of materials:
 - Fuels which have been historically managed as valuable fuel products rather than being managed as waste.
 - Fuels which are produced as fuels and are unused products that have not been discarded (virgin materials). These fuels are not secondary materials or solid wastes unless discarded.
- Solid waste is defined as any garbage, refuse, sludge from a wastewater treatment plant, water supply treatment plant, or air pollution control facility and other discarded material, including solid, liquid, semi-solid, or contained gaseous material resulting from industrial, commercial, mining, and agricultural operations, and from community activities (40 CFR §258.2).
- Non-Hazardous Secondary Material (NHSM), as the name signifies, is a secondary material which is also non-hazardous. Secondary material, per 40 CFR Part 241, is any material that is not the primary product of a manufacturing or commercial process, and can include both post-consumer and scrap materials. NHSM is considered to be a solid waste unless determined otherwise through the standards and procedures provided in *Solid Wastes Used as Fuels or Ingredients in Combustion Units* (40 CFR Part 241), more commonly known as the NHSM Rule. There is a wide variety of NHSM that is used for fuel, such as tires and manure.

If the fuel meets the definition of “traditional fuel”, the analysis is straight forward: the combusted material has never been discarded and cannot be a solid waste. For example, coke oven gas generated during the production of coke from coal is a traditional fuel, as it comes from a virgin material. However, determining whether or not a “non-traditional” fuel is a solid waste

is not as clear-cut. For example, a common misperception is that landfill gas or tire derived fuel are classified as a solid waste. However, landfill gas is actually a gaseous fuel under Boiler MACT because landfill gas is an uncontained gaseous stream and does not meet the definition of “contained gaseous material”. The distinction between solid waste and a non-traditional fuel gets more complex when the fuel is NHSM based. For example, scrap tires managed under the oversight of an established tire collection program and used for fuel are not solid waste.

The NHSM rule generally established standards and procedures for identifying whether NHSM are solid wastes or non-waste when used as fuels or ingredients in combustion units. Basically, if NHSM has a higher level of contaminants than a “traditional fuel,” the NHSM is solid waste. In accordance with the NHSM rule, if the material falls into one of the categories under 40 CFR 241.3(b) and also satisfies the applicable legitimacy criteria in 40 CFR 241.3(d), then the NHSM is not considered to be a solid waste when combusted. Additionally, EPA identified specific materials as categorical non-waste fuels. To summarize the NHSM rule, the following materials are considered NHSM that can be used as fuel in a combustion unit (as long as the legitimacy criteria is met):

- The material that has been determined through a case-by-case petition process not to have been discarded and to be indistinguishable in all relevant aspects from a fuel product.
- The material is used as a fuel that remains within the control of the generator (whether at the site of generation or another site the generator has control over).
- The material is used as an ingredient in a manufacturing process (whether by the generator or outside the control of the generator).
- The material has been sufficiently processed to produce a fuel or ingredient product that meets the legitimacy criteria.
- The material has been identified as a categorical non-waste fuel by EPA under 40 CFR §241.4(a). Sources that combust a categorically exempt non-waste NHSM must document that the NHSM is categorically exempt as part of the record keeping requirements. Materials that have received a categorical non-waste determination from the EPA are:
 - Scrap tires that are managed under established tire collection programs;
 - Resinated wood;
 - Coal refuse that has been recovered from legacy piles and processed in the same manner as currently-generated coal refuse; and

- Dewatered pulp and paper sludges burned on-site at facilities that use a significant portion of materials as fuels, where such dewatered sludges are managed in a manner that preserves the meaningful heating value of the materials.
- Construction and demolition (C&D) wood processed from C&D debris according to best management practices.
- Paper recycling residuals generated from the recycling of recovered paper, paperboard and corrugated containers and combusted by paper recycling mills whose boilers are designed to burn solid fuels.
- Creosote-treated railroad ties that are processed and then combusted in the following types of units:
 - (i) Units designed to burn both biomass and fuel oil as part of normal operations and not solely as part of startup or shutdown operations, and
 - (ii) Units at major source pulp and paper mills or power producers subject to 40 CFR 63 Subpart DDDDD that had been designed to burn biomass and fuel oil, but are modified (e.g. oil delivery mechanisms are removed) in order to use natural gas instead of fuel oil as part of normal operations and not solely as part of startup or shutdown operations.

The legitimacy criteria assure that potential environmental impacts from air pollution are minimized when NHSM is combusted to recover energy. NHSM that meets legitimacy criteria are not solid waste under 40 CFR 241.3(d) are defined as follows:

- Managed as a valuable commodity such that the storage of the NHSM does not exceed reasonable time frames, and releases to the environment are prevented;
- Meaningful heating value and used as a fuel in a combustion unit that recovers energy; and
- Contains contaminants or groups of contaminants at levels comparable in concentration or lower than those in traditional fuels which the combustion unit is designed to burn. EPA maintains that pollutant levels are comparable when they “fall within a small acceptable range” (76 FR 15524).

Step Three – Ensure the boiler or process heater is industrial, commercial, or institutional, and not residential.

Boiler MACT establishes national emission limitations and work practice standards for HAPs emitted from industrial, commercial, and institutional boilers and process heaters located at a major source of emissions. The rule does NOT apply to residential boilers and process heaters.

- Industrial boilers and process heaters – typically provides electricity, steam, and/or hot water and are generally located within factories, refineries, manufacturing plants, and chemical plants.
- Commercial boilers and process heaters – typically provides electricity, steam, and/or hot water and are generally located within shopping malls, hotels, apartments, and amusement parks.
- Institutional boilers and process heaters – typically provides electricity, steam, and/or hot water and are generally located within nursing homes, hospitals, universities, prisons, and courthouses. Many boilers and process heaters located at military installations are considered to be institutional. NOTE: Boilers servicing small family housing units located on USAF bases are usually not considered to be institutional (see definition of residential boilers and process heaters below).
- Residential boilers and process heaters – typically provides electricity, steam, and/or hot water and are located within single family dwellings, duplexes, or a single unit residence that has been converted into apartments or condos (includes up to four units). For example, boilers providing heat to an on base four-plex residential housing unit would not be subject to Boiler MACT, but a boiler providing heat to dormitory-type barracks is likely subject to Boiler MACT.

Step Four – Determine if the boiler or process heater is located at an area or major Source of emissions.

Boiler MACT (40 CFR Part 63, Subpart DDDDD) and Boiler GACT (40 CFR Part 63, Subpart JJJJJ) are sometimes collectively referred to as Boiler MACT. However, these rules differ considerably in applicability and standards. Boiler MACT applies to industrial, commercial, and institutional boilers and process heaters located at a MAJOR source of HAPs; however, Boiler GACT applies to industrial, commercial, and institutional boilers located at an AREA source of HAPs.

Check with the Base Environmental Management office to confirm if the facility is a Major or Area source for HAP. The Major/Area classification of the source is important because Major Sources are subject to far more regulations than Area Sources. A Major Source is defined

as a stationary source or group of stationary sources located within a contiguous area and under common control that emits, or has the Potential-to-Emit (PTE), 10 tons per year or more of a single HAP or 25 tons per year or more of a combination of all HAPs. PTE is the maximum quantity of HAPs a source could emit in a year given the physical and operational design. Potential emissions can include reductions for control equipment or other process limitations if they are included in a federally enforceable permit or applicable federal regulation. Applicability is based on the facility emissions, not the individual unit's emissions. Facilities that are not Major Sources are classified as Area Sources.

Step Five – Determine if the boiler or process heater is excluded from Boiler MACT.

Although there are no de minimis thresholds for applicability, Boiler MACT allows exemptions for specific types of boilers and process heaters. Carefully review and compare the following list of exemptions to the boiler or process heater in question:

- An electric utility steam generating unit (EGU) covered by Subpart UUUUU of Part 63 or a natural gas-fired EGU as defined in Subpart UUUUU of Part 63 firing at least 85 percent natural gas on an annual heat input basis (40 CFR 63.9980 to 63.10042, Subpart UUUUU - National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units).
- Recovery boilers or furnaces covered by 40 CFR 63.860 to 63.868, Subpart MM — National Emissions Standards for Hazardous Air Pollutants for Chemical Recovery Combustion Sources at Kraft, Soda, Sulfite, and Stand-Alone Semi Chemical Pulp Mills.
- Boilers or process heaters that are used specifically for research and development, including test steam boilers used to provide steam for testing the propulsion systems on military vessels. This does NOT include units that provide heat or steam to a process at a research and development facility.
- Hot water heaters, which are a closed vessel with a capacity of no more than 120 U.S. gallons in which water is heated by combustion of gaseous, liquid, or biomass/bio-based solid fuel and is withdrawn for use externally to the vessel. Hot water boilers combusting gaseous, liquid, or biomass fuel with a heat input capacity less than 1.6 MMBtu/hr are included in this definition. Hot water heater includes tankless units that provides on-demand hot water.
- Refining kettles covered by 40 CFR 63.541 to 63.551, Subpart X - National Emissions Standards for Hazardous Air Pollutants from Secondary Lead Smelting.

- Ethylene cracking furnaces covered by 40 CFR 63.1100 to 63.1114, Subpart YY - National Emissions Standards for Hazardous Air Pollutants for Source Categories: Generic Maximum Achievable Control Technology Standards.
- Blast furnace stoves as described in EPA publication EPA-453/R-01-005 (incorporated by reference, see §63.14).
- Boilers or process heaters that are part of the affected source subject to another NESHAP under 40 CFR 63.
- Boilers or process heaters that are used as a control device to comply with another standard under 40 CFR 60, 40 CFR 61, 40 CFR 63, or 40 CFR 65, provided that at least 50 percent of the heat input during any 3 consecutive calendar years to the boiler is provided by the gas stream that is regulated under another NESHAP.
- Temporary boilers and process heaters, which include any gaseous or liquid fuel boiler that is designed to, and is capable of, being carried or moved from one location to another (for example by 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 within the facility and performs the same or similar function for more than 12 consecutive months, unless the appropriate regulatory authority grants an extension. 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 two years, and operates at that facility for at least three months each year.
 - The equipment is moved from one location to another in an attempt to circumvent the residence time requirements of this definition.
- Blast furnace gas fuel-fired boilers and process heaters, which are defined as industrial, commercial, or institutional boilers or process heaters that receive 90 percent or more of their total annual gas volume from blast furnace gas.
- Boilers and process heaters specifically listed as an affected source in any New Source Performance Standards or emissions guidelines established under Section 129 of the CAA dealing with solid waste combustion.

- Boilers and process heaters that burn hazardous waste covered by 40 CFR 63.1200 to 63.1221 Subpart EEE - National Emission Standards for Hazardous Air Pollutants from Hazardous Waste Combustors (aka, the HWC MACT).
- Residential boilers used to provide heat and/or hot water and/or as part of a residential combined heat and power system. Included are boilers located at an institutional facility or commercial/industrial facility used primarily to provide heat and/or hot water for the following:
 - A dwelling containing four or fewer families; or
 - A single unit residence that has since been converted or subdivided into condominiums or apartments.

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2 BOILER OR PROCESS HEATER SUBCATEGORY DETERMINATION

2.1 Introduction

To determine the correct subcategory of the boiler or process heater and the appropriate regulations that will apply, the following information is required:

- The rated design heat input capacity as measured in Million British Thermal Units per hour (MMBtu/hr).
- The construction or reconstruction date of the boiler or process heater.
- The type of fuel(s) combusted in the boiler or process heater.
- The percentage of the annual heat input supplied by each fuel (if multi-fueled).
- Whether or not the boiler or process heater has a federally enforceable average annual capacity factor of no more than 10 percent.

Additionally, the following information is needed if the boiler or process heater has a rated design heat input capacity of 10 MMBtu/hr or greater and is in the solid fuel subcategory:

- The design/firing configuration type of the boiler or process heater (i.e., stoker, pulverized coal).

NOTE: Subcategories apply to individual boilers and process heaters on a case-by-case basis, not an entire facility.

2.2 Gathering Boiler and Process Heater Information

RATED HEAT INPUT CAPACITY: The rated design heat input capacity (boiler size) is measured in million British thermal units per hour, or MMBtu/hr. **The heat input capacity on the burner's or process heater's nameplate will be used to determine rated heat input capacity** (the heat input capacity on the boiler's and burner's nameplate should be the same, but sometimes they are not).

Occasionally, the boiler's or process heater's data may be missing from the records or needs verification. If a physical examination of the boiler or process heater is necessary to gather information to ascertain applicability, contact shop or maintenance personnel familiar with the equipment; they should know where to locate the nameplates, stickers, or other attachments that can provide model number, serial number, and other important data.

If the nameplate and/or sticker is painted over or otherwise not decipherable, search for the serial number (the serial number is useful when contacting the dealer or manufacturer for information). In those situations, the manufacturer's representative may need to be contacted to obtain/verify the information. When contacting a distributor or manufacturer for information, always be prepared to provide the complete model and serial number to receive accurate and faster assistance. Many manufacturers have a searchable database on their website; however, keep in mind that the boiler may have been customized to meet military requirements, so the exact engine may not be represented.

IMPORTANT: Safety precautions should be followed at ALL times when examining the boiler/process heater/burner and any associated equipment. Safe and responsible examination of the unit is of the utmost importance. Always obtain assistance from technicians that are familiar with the equipment and follow all safety related instructions (e.g., the use of safety goggles, hard-hats). Never handle the boiler, process heater, burner, or connected equipment (including opening doors) while it is operating. The danger is not only from moving parts, the components can get extremely hot and can cause severe burns (do not touch equipment while running or soon after it is turned off). Additionally, the equipment may be off, but an automatic start mechanism or stored energy may unexpectedly start equipment during inspection. The Occupational Safety and Health Administration created the Lock-Out/Tag-Out standard to prevent the unintentional activation of machinery or equipment while inspection, maintenance, or other servicing activities are performed. The Lock-Out/Tag-Out procedures establish the minimum requirements for the lockout of energy isolating devices whenever servicing or maintenance is done on boilers. For that reason, **always be sure to have the assistance of a person authorized to conduct Lock-Out/Tag-Out procedures if intrusive examination of the boiler, process heater, or burner is necessary.**

2.3 Determine Size of Boiler or Process Heater

Boiler and process heater size is expressed in terms of rated design heat input capacity (heating capacity at design conditions) and is most often measured in MMBtu/hr. One British Thermal Unit (Btu) equals the amount of energy needed to heat one pound of water one degree Fahrenheit or the energy given off by burning one wooden match.

Boilers and process heaters frequently have a nameplate listing the rated heat input capacity on the unit. This rated capacity may have also been reported to the entity insuring the boiler or to the State labor and safety inspector. The rated heat capacity is defined below.

- Large - Major Source boilers and process heaters that have a heat input capacity equal to or greater than 10 MMBtu/hr.

- Small - Major Source boilers and process heaters that have a heat input capacity less than 10 MMBtu/hr.

2.4 Determine if Boiler or Process Heater is New, Reconstructed, or Existing

Boiler MACT applies to new, reconstructed, and existing boilers and process heaters; however, the requirements will differ depending on the date of construction or reconstruction.

Construction or reconstruction commences on the date of the contractual obligation to undertake and complete construction or on the date the act of construction or reconstruction of the boiler or process heater began (40 CFR 63.2).

A new boiler or process heater is not necessarily one that was very recently constructed. For the purposes of Boiler MACT, the date a boiler or process heater commenced construction or reconstruction dictates if it is considered “new” or “existing”. Even though a boiler or process heater may be a few years old, the EPA considers a boiler or process heater constructed or reconstructed after the date of the original Boiler MACT rule (4 June 2010) to be “new”. New, reconstructed, and existing definitions for boilers and process heaters are provided below.

- New - The boiler or process heater is a new source if construction commenced after 4 June 2010, and met the applicability criteria at the time construction commenced. [§63.7490(b)]
- Reconstructed - The boiler or process heater is a reconstructed source if reconstruction of the boiler commenced after 4 June 2010, and met the applicability criteria at the time reconstruction commenced [§63.7490(c)]. Reconstruction is replacement of components of an affected or a previously nonaffected source to such an extent that:
 - The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable new source; and
 - It is technologically and economically feasible for the reconstructed source to meet the relevant standard(s) established by the Administrator (or a State) pursuant to section 112 of the Act. Upon reconstruction, an affected source, or a stationary source that becomes an affected source, is subject to relevant standards for new sources, including compliance dates, irrespective of any change in emissions of hazardous air pollutants from that source. (40 CFR 63.2)
- Existing - A boiler or process heater is existing if it is not new or reconstructed (construction or reconstruction commenced on or before 4 June 2010). [§63.7490(d)]

- An EGU that meets the applicability requirements of Subpart DDDDD after 1 April 2013 due to a change (e.g., fuel switch) is considered to be an existing source. [§63.7490(e)]

2.5 Determine Boiler or Process Heater's Fuel Classification Subcategory

The majority of subcategories in Boiler MACT are based on the classification of fuel the boiler or process heater combusts on an annual heat input basis. There is also a subcategory based on use limitations (Limited Use) and a subcategory based on geographical location (Noncontinental for units in the large liquid fuel subcategory). Large boilers and process heaters in the Solid Fuel subcategory are further categorized by design/combustion type. To simplify the process of selecting the proper subcategory(s), this Guide divides the EPA's subcategories into three groups. One subcategory from each group is selected for each boiler or process heater, as applicable.

First, determine if the boiler or process heater falls into the "Limited Use" subcategory. The fuel type combusted, the age, or size of the boiler or process heater does not matter. Any boiler or process heater that has a federally enforceable average annual capacity factor of no more than 10 percent is considered to be Limited Use. New and existing Limited Use boilers and process heaters are subject to a tune-up every 5 years, but are not subject to emission or operating limits, no matter the size. For each boiler that meets the definition of limited use boiler, keep a copy of the federally enforceable permit and records of fuel use to prove applicability. Pay careful attention to the following definitions to ensure applicability of this subcategory:

- The annual capacity factor is the ratio between the actual heat input to a boiler or process heater from the fuels burned during a calendar year and the potential heat input to the boiler or process heater had it been operated for 8,760 hours during a year at the maximum steady state design heat input capacity.
- Federally enforceable means all limitations and conditions that are enforceable by the EPA Administrator, including, but not limited to, the requirements of 40 CFR Parts 60, 61, 63, and 65, requirements within any applicable State implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 40 CFR 51.24.

If the boiler or process heater is not Limited Use, the fuel usage for the preceding 12-month period prior to the required compliance demonstration (e.g., tune-up, performance test) needs to be determined. For a single fueled boiler or process heater, simply compare the type of fuel burned during the 12-month period with the fuel subcategory definitions to determine the appropriate fuel subcategory for the boiler or process heater. A newly constructed boiler or process heater (or a reconstructed/modified source resulting in a fuel change) would not have a preceding fuel use period; therefore, the fuel consumption would be calculated using the fuel limitations provided in the permit authorizing the construction, installation, or modification or on the fuel throughput as limited by the boiler's design capacity. The next section in this Guide describes how to determine the appropriate fuel subcategory for a multiple fueled boiler or process heater, which is a more complex process.

NOTE: Boilers and process heaters that use supplemental fuel for start-up, unit shut-down, and transient flame stability purposes only, still qualify as units that burn a single type of fuel. §63.7510(a)(2)(i)

A careful evaluation of fuel use is important; operating as a single fuel boiler can significantly reduce compliance requirements and avoid the complexities associated with conducting a multiple-fuel performance test and fuel analysis (a benefit of a single fuel unit is that fuel analysis is not required when conducting initial performance testing).

The subcategories listed in Boiler MACT as well as the definitions and conditions for each subcategory are provided below (subcategories and definitions are located in §63.7499 and §63.7575 of Subpart DDDDD, respectively). Make note that there are situations when a boiler or process heater can be in more than one subcategory (but only one subcategory from each group). For example, a large pulverized coal boiler will belong to the following three subcategories:

- Unit Designed to Burn Solid Fuel (Group One)
- Unit Designed to Burn Coal/Solid Fossil Fuel (Group Two)
- Pulverized Coal (Group Three)

2.5.1 Subcategory Group One

NOTE: Subcategory Group One applies to ALL boilers and process heaters, excluding Limited Use

Each boiler or process heater subject to Boiler MACT will fall into ONE of the following subcategories (with the exception of the Liquid Fuel subcategory which is further divided into "Light" or "Heavy" liquid subcategories). Small boilers and process heaters (heat input capacity less than 10 MMBtu/hr) will only select a subcategory from Group One (no other Group will apply). These subcategories are defined below.

2.5.1.1 Unit Designed to Burn Solid Fuel

This category includes any boiler or process heater that burns only solid fuels or at least 10 percent solid fuel on an annual heat input basis in combination with liquid fuels or gaseous fuels.

- Solid fuel means any solid fossil fuel or biomass or bio-based solid fuel. Solid fossil fuel includes, but is not limited to, coal, coke, petroleum coke, and tire derived fuel.
- Biomass or bio-based solid fuel means any biomass-based solid fuel that is not a solid waste.

2.5.1.2 Unit Designed to Burn Gas-One

“Gas One” includes natural gas, refinery gas, or other Gas One fuel.

- “Other Gas One” fuel means a gaseous fuel that is not natural gas or refinery gas and does not exceed a maximum concentration of 40 micrograms/cubic meters of mercury (fuel analysis will be required). For example, a boiler or process heater combusting coke oven gas can qualify as a Gas One unit if the coke oven gas meets the mercury criteria as evidenced by the fuel analysis. To demonstrate that a gaseous fuel other than natural gas or refinery gas qualifies as an “other Gas One” fuel, as defined in 40 CFR 63.7575, a fuel specification analyses for mercury must be conducted according to the procedures in paragraphs (g) through (i) of 40 CFR 63.7521, and as stated in Table 6 to Subpart DDDDD. Refer to subsection 2.4.5.1, *Fuel Qualifying as Gas One*, for further information.

Boilers and process heaters that fit into this subcategory will fall into one of the following scenarios:

- **Gas One-Fired Boiler and Process Heater Scenario One** – The boiler is capable of burning ONLY Gas One fuels or burns ONLY Gas One fuels (natural gas, refinery gas, or other Gas One fuel). No solid or liquid fuels are/would be burned.

OR

- **Gas Two-Fired Boiler and Process Heater Scenario Two** – The boiler burns primarily Gas One fuels (natural gas, refinery gas, or other Gas One fuel) and has the capability to burn liquid fuels; however, liquid fuels are/would be burned only during periods of gas curtailment, gas supply emergencies, or periodic testing on liquid fuels not to exceed 48 hours per calendar year. No solid fuels are burned.
 - There is no limit on the number of hours a gas-fired boiler or process heater may burn oil during periods of natural gas curtailment or supply emergencies.

- Gas One fuel boilers and process heaters that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, *not to exceed a combined total of 48 hours during any calendar year*, are included in this definition.
- Gas One fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply interruptions *of any duration* are also included in this definition.
- A boiler or process heater that exceeds the 48-hour limitation for burning liquid fuel during any calendar year will be in the liquid fuel subcategory.

2.5.1.3 Unit Designed to Burn Gas Two

Gas Two (2) fuels include any gaseous fuels that are not in the Gas One fuel subcategory. For example, coke oven gas that does not meet the mercury criteria to be considered a Gas One fuel is Gas Two. The boilers and process heaters that fit into this subcategory include:

- Any boiler or process heater that is not in the Gas One subcategory and burns any gaseous fuels in combination with less than 10 percent solid fossil fuel, less than 10 percent biomass, and no liquid fuels on an annual heat input basis.
- Gaseous fuel boilers and process heaters that are not in the unit designed to burn Gas One subcategory and that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year, are included in this subcategory.
- Gaseous fuel boilers and process heaters that are not in the unit designed to burn Gas One subcategory and that burn liquid fuel during periods of gas curtailment or gas supply interruption of any duration are also included in this subcategory.

2.5.1.4 Unit Designed to Burn Liquid Fuel

This subcategory includes any boiler or process heater that burns any liquid fuel but less than 10% coal or other solid fossil fuel and less than 10% biomass or bio-based solids on an annual heat-input-basis average, either alone or in combination with gaseous fuels. The additional subcategories that fall under this fuel subcategory are (choose either the Heavy or Light liquid subcategory):

- **Unit Designed to Burn Heavy liquids** – At least 10 percent of the heat input from liquid fuels on an annual heat input basis comes from heavy liquids (residual oils such as #4, #5, and #6 oil).

- **Unit Designed to Burn Light liquids** - Burns distillate oils (#1, #2 oil, biodiesel, vegetable oils) and is not in the Heavy Liquid Subcategory.

2.5.2 Subcategory Group Two

Subcategory Group Two applies to liquid and solid fuel boilers and process heaters with a heat input capacity of 10 MMBtu/hr or greater ONLY (excludes Limited Use).

2.5.2.1 Liquid Fuel Subcategory

Large boilers and process heaters in the Liquid Fuel subcategory (Light and Heavy) have a geographical category, as described below, that may apply as well:

- **Unit Designed to Burn Liquid Fuel that are Noncontinental Units** - Boiler or process heater meeting the definition of the Unit Designed to Burn Liquid subcategory and the unit is located in the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

2.5.2.2 Solid Fuel Subcategory

Large boilers and process heaters in the Solid Fuel subcategory are further divided into Coal/Solid Fossil Fuel and Biomass/Bio-based Fuel subcategories. In addition to a Group One subcategory, the boiler or process heater will also belong to ONE of the following subcategories:

- **Unit Designed to Burn Coal/Solid Fossil Fuel** - Includes any boiler or process heater that burns any coal or other solid fossil fuel alone or at least 10 percent coal or other solid fossil fuel on an annual heat input basis in combination with liquid fuels, gaseous fuels, or less than 10 percent biomass and bio-based solids on an annual heat input basis.
 - Coal means all solid fuels classifiable as anthracite, bituminous, sub-bituminous, or lignite by ASTM D388 (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, including but not limited to, solvent-refined coal, coal-oil mixtures, and coal-water mixtures. Coal derived gases and coal derived liquids are excluded from this definition (coal derived liquids are considered to be a liquid fuel type).
 - Coal refuse means any by-product of coal mining or coal cleaning operations with an ash content greater than 50 percent (by weight) and a heating value less than 13,900 kilojoules per kilogram, which is equivalent to 6,000 Btu per pound (Btu/lb), on a dry basis.

- **Unit Designed to Burn Biomass/Bio-based Solid** - Includes any boiler or process heater that burns at least 10 percent biomass or bio-based solids on an annual heat input basis in combination with solid fossil fuels, liquid fuels, or gaseous fuels. Biomass or bio-based solid fuel is any biomass-based solid fuel that is not a solid waste. This includes, but is not limited to, the following materials:
 - Wood residue
 - Wood products, such as 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, and coffee bean hulls and grounds.

2.5.3 Subcategory Group Three

Subcategory Group Three applies to large solid fuel units ONLY, excluding Limited Use

Fuel burners for liquid and gaseous fuels are similar to each other with very little variance in design. However, solid fueled boilers and process heaters have a variety of approaches to fuel combustion which impacts emissions. EPA recognized that certain emissions can differ between solid fueled units due to combustion design even though the boiler or process heater combusts a similar fuel, particularly filterable PM and CO. Consequently, the EPA established emission limits for those pollutants based on the combustion or design type for solid fueled boilers. Therefore, in addition to the Group One and Group Two subcategories, a large solid fueled boiler or process heater will also belong to ONE of the following design type subcategories:

- Pulverized Coal Boilers.
- Stokers/Others Designed to Burn Coal/Solid Fossil Fuel.
- Fluidized Bed Units Designed to Burn Coal/Solid Fossil Fuel.
- Fluidized Bed Units with an Integrated Fluidized Bed Heat Exchanger Designed to Burn Coal/Solid Fossil Fuel.
- Stokers/Sloped Grate/Other Units Designed to Burn Kiln-Dried Biomass/Bio-based Solids.
- Fluidized Bed Units Designed to Burn Biomass/Bio-based Solids.
- Suspension Burners Designed to Burn Biomass/Bio-based Solids.
- Fuel Cells Designed to Burn Biomass/Bio-based Solids.

- Hybrid Suspension/Grate Burners Designed to Burn Wet Biomass/Bio-based Solids.
- Stokers/Sloped Grate/Other Units Designed to Burn Wet Biomass/Bio-based Solids.
- Dutch Ovens/Pile Burners Designed to Burn Biomass/Bio-based Solids.

The definitions of the applicable boiler and process heater design types having a firing configuration per §63.7575 of the Rule are as follows:

- **Pulverized Coal Boilers (coal/solid fuel)** - A boiler in which pulverized coal or other solid fossil fuel is introduced into an air stream that carries the fuel to the combustion chamber of the boiler where it is fired in suspension.
- **Stoker (coal/solid fossil fuel, kiln-dried biomass fuels, or wet biomass fuel)** - A unit consisting of a mechanically operated fuel feeding mechanism, a stationary or moving grate to support the burning of fuel and admit under-grate air to the fuel, an overfire air system to complete combustion, and an ash discharge system. These include the following:
 - Wet biomass fuel exceeding 20 percent moisture.
 - Kiln-dried biomass fuel containing 20 percent or less moisture.
- **Sloped Grate (kiln-dried biomass fuels or wet biomass fuel)** – A unit where the solid fuel is fed to the top of the grate from where it slides downwards; while sliding the fuel first dries and then ignites and burns. The ash is deposited at the bottom of the grate. Fluidized bed, Dutch oven, pile burner, hybrid suspension grate, suspension burners, and fuel cells are not considered to be a sloped grate design.
- **Fluidized Bed (coal/solid fossil fuel or biomass/bio-based fuel)** - A unit using a fluidized bed combustion (FBC) process that is not in the pulverized coal subcategory. FBC is a process where a fuel is burned in a bed of granulated particles which are maintained in a mobile suspension by the upward flow of air and combustion products.
- **Fluidized Bed Units with an Integrated Fluidized Bed Heat Exchanger (coal/solid fossil fuel)** - A unit utilizing a FBC where the entire tube surface area is located outside of the furnace section at the exit of the cyclone section and exposed to the flue gas stream for conductive heat transfer. This design applies only to boilers in the unit designed to burn coal/solid fossil fuel subcategory that fire coal refuse.
- **Suspension Burner (biomass/bio-based fuel)** - A unit designed to fire dry biomass solid particles that are blown into the furnace like in the pulverized coal subcategory.

Combustion of the fuel material is completed on a grate or floor below. The biomass fuel combusted in the unit shall not exceed 20 percent moisture on an annual heat input basis.

- **Dutch Oven/Pile burner (biomass/bio-based fuel)** - A unit having a refractory-walled cell connected to a conventional boiler. Fuel materials enter through an opening in the roof of the Dutch oven and burn in a pile on its floor. Pile burner means a boiler design where the fuel has a high relative moisture content (typically biomass). Grates support the fuel allowing underfire air to flow up through the grates and provide oxygen for combustion, cool the grates, promote turbulence in the fuel bed, and fire the fuel.
- **Fuel Cell (biomass/bio-based fuel)** - A unit where the fuel is dropped onto suspended fixed grates and is fired in a pile. The refractory-lined fuel cell uses combustion air preheating and positioning of secondary and tertiary air injection ports to improve boiler efficiency.
- **Hybrid Suspension/Grate (biomass/bio-based fuel)** - A unit designed with air distributors to spread the fuel material over the entire width and depth of the boiler combustion zone. The biomass fuel combusted in these units exceeds moisture content of 40 percent on an as-fired basis. The drying and much of the combustion of the fuel takes place in suspension, and the combustion is completed on the grate or floor of the boiler.
- **Other** - A unit that is not classified as a Dutch oven, fluidized bed, fuel cell, hybrid suspension grate boiler, pulverized coal boiler, stoker, sloped grate, or suspension boiler as defined in Subpart DDDDD.

2.5.4 Determining the Fuel Subcategory for Multiple Fueled Units

Determining the fuel type subcategory for a boiler or process heater that burns a single fuel is usually not complicated. However, if the boiler or process heater burns more than one fuel (with the exception of start-up, shut-down, and flame stability purposes), the fuel subcategory is determined based on the heat input contribution from each fuel burned during the 12 months preceding the compliance test or tune-up.

EPA concluded that subcategory classification based on the percentage of fuels combusted was appropriate for boilers and process heaters considering variations in emissions and fuel efficiencies. For example, a boiler combusting both coal and biomass is considered to be in the biomass subcategory as long as the boiler burns at least 10 percent biomass on an annual heat input basis. This is because the emissions are influenced more by the biomass burned than the coal burned at that percentage. Essentially, EPA established a hierarchy of fuel subcategories, based on the percentage of fuels combusted on an annual heat input basis. The percentages are contained within the subcategory definitions provided in §63.7575 of the Rule and in the

previous section of this Guide. Table 2-1, *Fuel Type Determination Table for Multiple Fueled Units*, demonstrates the percentages that define the fuel subcategories:

Table 2-1. Fuel Type Determination Table for Multiple Fueled Units

Regulated Fuel Classification Hierarchy					
Subcategory:	Fuels Burned on an Annual Heat Input Basis				
	Biomass	Coal	Liquid**	Gas 2*	Gas 1*
Unit Designed to Burn Biomass/Bio-based Solid Fuel	≥10%	Any Amount	Any Amount	Any Amount	Any Amount
Unit Designed to Burn Coal/Solid Fossil Fuel	<10%	≥10%	Any Amount	Any Amount	Any Amount
Unit Designed to Burn Liquid**	<10%	<10%	Any Amount	Any Amount	Any Amount
Unit Designed to Burn Gas 2*	<10%	<10%	None	Any Amount	Any Amount
Unit Designed to Burn Gas 1*	None	None	None	None	Any Amount
*Gas 1 and Gas 2 boilers and process heaters can burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training not to exceed a total of 48 hours per calendar year and can burn liquid fuel during periods of gas curtailment or gas supply interruptions for any duration. ** Liquid Fuels further categorized into “Heavy” or “Light” Liquid Fuel Subcategories. If at least 10 percent of the heat input from liquid fuels on an annual heat input basis comes from heavy liquids, the unit is in the Heavy Liquid subcategory.					

2.5.4.1 Calculating Annual Heat Input Basis

A multiple-fueled boiler or process heater’s fuel subcategory determination is based on the percentage of fuel consumed by the unit in the 12-month period preceding the required compliance demonstration (e.g. the required tune-up or performance test). The Annual Heat Input Basis for each fuel burned in a multiple-fueled boiler or process heater needs to be calculated following these steps. An example of an Annual Heat Input Basis calculation is provided below.

Step 1: Determine the Annual Fuel Consumption of Each Fuel

Add the total amount of each fuel type consumed in the 12 months preceding the compliance demonstration (tune-up or Performance Test). Identify the classification for each fuel burned in accordance with the definitions in §63.7575 of the Rule, also included in the previous section of this Guide.

Annual Fuel Consumption Total (Tons) for Boiler:

		Bituminous Coal	Anthracite	Wood
1	January	950	125	1100
2	February	1350	110	800
3	March	1780	75	820
4	April	950	120	600
5	May	800	80	500
6	June	980	50	0
7	July	700	45	250
8	August	875	45	0
9	September	950	30	0
10	October	1225	0	0
11	November	1250	0	275
12	December	1120	50	850
	Total:	12,930	730	5195

Step 2: Determine the High Heat Value for Each Fuel

The High Heat Value (HHV) is the amount of heat produced by the complete combustion of a unit quantity of fuel. Determine the HHV for each fuel type combusted by:

- Obtaining the data from the fuel supplier;
- Using the calculation methodologies typically used for EPA Greenhouse Gas Reporting Rule as defined in 40 CFR part 98, Subpart C; or
- Conducting a site-specific Performance Test.
- Other published sources of HHV may also be used.

For this example, the HHV for the fuels combusted (MMBtu/short ton) during the year per the default values in 40 CFR Part 98 Subpart C, Table C–1 are:

- Bituminous Coal 24.93
- Anthracite 25.09
- Wood 17.48

Step 3: Calculate the Annual Heat Input of Each Fuel

Multiply the total annual consumption by the HHV of each fuel to determine the annual heat input of each fuel.

$$Heat\ Input_{annual} = Fuel\ Consumption_{annual} \times HHV$$

$$Heat\ Input(Wood)_{annual} = 5195 \frac{ton}{yr} \times 17.48 \frac{MMBtu}{short\ ton} = 90,808.6 \frac{MMBtu}{yr}$$

Fuel	Fuel Consumed/year	HHV	Annual Heat Input
Bituminous Coal	12930	24.93	322344.9
Anthracite	730	25.09	18315.7
Wood	5195	17.48	90808.6

Step 4: Total the Annual Heat Input from all Fuel Types

Add the calculated annual heat input for all fuel types.

$$Heat\ Input\ (total)_{annual} = \sum_{i=1}^n (Heat\ Input_{annual_i} + \dots + Heat\ Input_{annual_n})$$

$$Heat\ Input\ (total) = (322344.9 + 18315.7 + 90808.6) = 431,469.2 \frac{MMBtu}{yr}$$

Step 5: Total the Annual Heat Input from Each Fuel Classification

Identify the classification for each fuel according to definitions under 40 CFR 63.7575. Find the total annual heat input from each fuel classification by adding together the calculated annual heat input of each fuel with the same fuel classification.

Solid Fossil Fuel/Coal (MMBtu/yr)		Biomass (MMBtu/yr)
Bituminous Coal	Anthracite Coal	Wood
322,344.9	18,315.7	90,808.6
340,660.6		90,808.6

Step 6: Determine the Fuel Subcategory Based on the Annual Heat Input of Each Fuel Classification

Divide the total annual heat input from each fuel classification by the total annual heat input from all fuel types, then multiply by 100%.

$$\%_{Fuel\ Subcategory} = \left(\frac{Annual\ Heat\ Input_{Fuel\ Subcategory}}{Heat\ Input\ (total)_{annual}} \right)$$

$$\% (\text{Coal}) = \left(\frac{340,660.6 \frac{\text{MMBtu}}{\text{yr}}}{431,469.2 \frac{\text{MMBtu}}{\text{yr}}} \right) \times 100 = 79\%$$

Solid Fossil Fuel/Coal		Biomass
Bituminous Coal	Anthracite	Wood
79%		21%

Step 7: Determine the Fuel Type Subcategory

Compare the percentage of each fuel classification on an annual heat input basis to the fuel subcategory definitions in §63.7575 to determine the appropriate fuel subcategory. The Group system (Group One, Group Two, Group Three, as applicable) provided in the previous section of this Guide should be used to determine all of the subcategories that may apply to the boiler or process heater.

In this example, more than 10% of the fuel combusted in the boiler on an annual heat input basis was biomass (wood); therefore, the boiler is in the Unit Designed to Burn Biomass/Bio-based Fuel Subcategory.

The calculations should be repeated before every compliance demonstration (e.g. tune-up or Performance Test) to ensure the boiler or process heater is complying with requirements of the correct fuel subcategory.

For illustration of possible subcategory scenarios for boilers and process heaters combusting multiple fuels, two examples are provided:

Example #1: Annual heat input basis of a large fluidized bed boiler combusting coal and wood:

Type of Fuel Combusted	Bituminous Coal	Wood and Wood Residue
% of Fuel on an Annual Heat Input Basis	75%	25%

This boiler belongs to the following subcategories:

- Unit Designed to Burn Solid Fuels (Group One).
- Unit Designed to Burn Biomass/Bio-based Solids (Group Two).
- Fluidized Bed Units Designed to Burn Biomass/Bio-based Solids (Group Three).

Although the boiler combusts more coal than wood/wood residue, the boiler burns at least 10% biomass/bio-based solids (wood/wood residue) on an annual heat input basis in combination with a solid fuel. This boiler will be regulated within the applicable solid fuel/biomass boiler subcategory, unless the unit burns less than 10 percent biomass. In this case, the Unit Designed to Burn Coal/Solid Fossil Fuel and the Fluidized Bed Units Designed to Burn Coal/Solid Fossil Fuel subcategories would then apply (the Unit Designed to Burn Solid Fuels will apply in both situations).

Example #2: This is an example of the annual heat input basis of a small boiler located in Hawaii combusting biodiesel, Gas 1, and Gas 2

Type of Fuel Combusted	Biodiesel*	Gas 2	Gas 1
% of Fuel on an annual heat input basis	20%	25%	55%

*The boiler burned biodiesel for 62 hours during the calendar year for periodic testing.

Although the boiler burned less liquid fuel than Gas 1 or Gas 2 fuels, the boiler belongs to the Unit Designed to Burn Light Liquid fuel subcategory for these reasons:

- The boiler burned more Gas 1 than the other fuels, but the boiler must burn only natural gas, refinery gas, or other Gas 1 fuels to be in the Gas 1 subcategory; therefore, the boiler is excluded from the Gas 1 subcategory.
- Gas 2 was not burned in combination with solid fossil fuel or biomass; however, more than 10 percent liquid fuel was burned on an annual heat input basis. Additionally, the boiler burned liquid fuel for more than 48 hours during the calendar year for periodic testing. The boiler is excluded from the Gas 2 subcategory.
- The boiler burned more than 10% liquid fuel and did not burn coal/solid fossil fuel or biomass/bio-based solids. The boiler burned biodiesel, which is a light liquid fuel, and did not burn any heavy liquid fuels. Therefore, the boiler is included in the light liquid fuel subcategory.
- The boiler is small; therefore, although the boiler is located in Hawaii (Noncontinental liquid fueled boiler), only the list of subcategories in Group One will apply.

2.5.5 Information Regarding the Gas 1 Subcategory

The compliance requirements for large boilers and process heaters in the Gas 1 Subcategory are *significantly* less cumbersome than for large boilers and process heaters in any other fuel Subcategory, besides Limited Use. Although Gas 1 boilers and process heaters must meet work practice standards, those units are not subject to numerical emission limits. Since compliance with Boiler MACT is not as complicated for a large Gas 1 unit as it is for a large boiler or

process heater in other fuel subcategories, it is important to understand what constitutes a Gas 1 boiler or process heater and how to ensure that such a boiler or process heater remains in that subcategory.

2.5.5.1 Fuel Qualifying as Gas One

The Gas One (1) fuel subcategory includes natural and refinery gas. A fuel specification analyses is NOT required for:

- Natural gas or refinery gas.
- Gaseous fuels that are subject to another subpart of Part 63, Part 60, Part 61, or Part 65.
- Gaseous fuels for units that are complying with the limits for units designed to burn Gas 2 (other) fuels.
- Gas streams directly derived from natural gas at natural gas production sites or natural gas plants.

Other gases, such as landfill gas, can qualify as an “other” Gas 1, if the Gas does not exceed 40 micrograms per cubic meter of mercury (per definition of “other Gas 1 fuel” in §63.7575). To demonstrate that a gaseous fuel other than natural gas or refinery gas qualifies as an “other Gas 1” fuel, a fuel specification analyses must be conducted for Hg according to the procedures in paragraphs (g) through (i) of §63.7521 and Table 6 to Subpart DDDDD, as applicable. In situations where sampling and analysis of the fuel gas itself are not possible or practical, measure Hg concentration in the exhaust gas when firing only the gaseous fuel to be demonstrated as an “other Gas 1 fuel” in the boiler or process heater according to the procedures in Table 6 to Subpart DDDDD.

A fuel analysis provided by a fuel supplier may be used if the fuel supplier uses the analytical methods specified in Table 6 to Subpart DDDDD. When using a fuel supplier’s fuel analysis, the owner or operator is not required to include the sample location and procedures used for collecting and preparing the samples in the site-specific fuel analysis plan.

If the fuel does not exceed the specifications, a signed certification needs to be included with the Notification of Compliance Status (NOCS) that demonstrates that the initial fuel specification test meets the gas specification outlined in the definition of “other” Gas 1 fuels.

If the fuel analysis meets the following criteria, the frequency of sampling is provided below for each scenario.

- The mercury constituents in the gaseous fuels are measured to be equal to or less than half of the mercury specification as defined in §63.7575, no further sampling needs to be conducted.
- The mercury constituents are greater than half but equal to or less than 75 percent of the mercury specification as defined in §63.7575, semi-annual sampling will need to be conducted.
 - If six consecutive semi-annual fuel analyses demonstrate 50 percent or less of the mercury specification, no further sampling needs to be conducted.
 - If any semi-annual sample exceeds 75 percent of the mercury specification, monthly sampling for that fuel must resume until 12 months of fuel analyses again are less than 75 percent of the compliance level.
- The mercury constituents are greater than 75 percent of the mercury specification as defined in §63.7575, monthly sampling is required.
 - If 12 consecutive monthly fuel analyses demonstrate 75 percent or less of the mercury specification, the fuel analysis frequency can be decreased to semi-annual for that fuel.

If the initial sample exceeds the Gas 1 mercury specification, each affected boiler or process heater combusting the fuel is NOT part of the unit designed to burn Gas 1 subcategory and the boiler or process heater MUST be in compliance with the emission and operating limits for the appropriate subcategory (typically the Gas 2 Subcategory). Additional monthly sampling can be conducted (while complying with the emission and operating limits for the appropriate subcategory) to demonstrate that the fuel qualifies as another Gas 1 fuel. If 12 consecutive monthly fuel analyses samples are at or below the Gas 1 mercury specification, each affected boiler or process heater combusting the fuel can elect to switch back into the unit designed to burn Gas 1 subcategory until the mercury specification is exceeded [§63.7540(c)].

2.5.5.2 Staying in the Gas 1 Subcategory

A boiler or process heater in the Gas 1 subcategory can burn ONLY natural gas, refinery gas, or other Gas 1 fuels. Boilers and process heaters in the Gas 1 subcategory can burn liquid fuel during periods of gas curtailment or gas supply interruptions of any duration and still be included in the Gas 1 subcategory; however, liquid fuel cannot be burned for more than a combined total of 48 hours in a calendar year for periodic testing of liquid fuel, maintenance, or operator training. A Gas 1 boiler or process heater violating those restrictions will be reclassified into a different subcategory. For example, a natural gas boiler that burns oil for more than 48 hours due to operator training would be reclassified as a “Unit Designed to Burn Liquid Fuel.”

Period of gas curtailment or supply interruption is a period of time during which the supply of gaseous fuel to a boiler or process heater is restricted or halted for reasons beyond the control of the facility. On-site gaseous fuel system emergencies or equipment failures qualify as periods of supply interruption when the emergency or failure is beyond the control of the facility. Reasons which do not qualify as a period of gas curtailment or supply interruption under the control of a facility include:

- The act of entering into a contractual agreement with a supplier of natural gas established for curtailment purposes.
- An increase in the cost or unit price of natural gas due to normal market fluctuations not during periods of supplier delivery restriction.

It is very important that fuel use is monitored and fuel analysis and usage records maintained to document that the boiler or process heater meets the requirements for a “Unit Designed to Burn Gas 1 fuel”. If a boiler or process heater in the Gas 1 subcategory uses an alternative fuel other than Gas 1 (or a gas that qualifies as “Gas 1”), keep records of the total hours per calendar year that alternative fuel is burned and the total hours per calendar year that the unit operated during periods of gas curtailment or gas supply emergencies.

Additionally, the Administrator will need to be notified of the alternative fuel use. If the facility intends to use a fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart of Part 63, Part 60, 61, or 65, or other Gas 1 fuel to fire the affected unit during a period of natural gas curtailment or supply interruption, a notification of alternative fuel use must be submitted within 48 hours of the declaration of each period of natural gas curtailment or supply interruption. The notification must include the information specified in paragraphs (f)(1) through (5) of §63.7545:

- Company name and address.
- Identification of the affected unit.
- Reason natural gas or equivalent fuel cannot be used, including the date when the gas curtailment was declared or the gas supply interruption began.
- Type of alternative fuel that the facility intends to use for the boiler or process heater.
- Dates when the alternative fuel use is expected to begin and end.

NOTE: If the boiler or process heater no longer qualifies as a “Unit Designed to Burn Gas 1”, all compliance demonstrations, including performance testing, must be conducted within 60 days of the effective date of the switch, unless the compliance demonstration was conducted within the previous 12 months (§63.7510).

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3 COMPLIANCE WITH BOILER MACT

3.1 Introduction

Boiler MACT establishes requirements to demonstrate initial and continuous compliance with work practice and emission limitations, including reporting, notifications, and recordkeeping. Additionally, the boiler or process heater must be operated and maintained in a manner consistent with safety and good air pollution control practices for minimizing emissions at all times.

3.1.1 Unknown Compliance Status of Boiler or Process Heater

If the compliance status of the boiler or process heater is unknown, conduct an evaluation to determine where the boiler or process heater is within the compliance process. If it is determined that the boiler or process heater has missing requirements, but the deadline has passed, immediately contact the AFCEC/CZTQ Air Quality Subject Matter Expert for a consult on developing a compliance strategy. If the deadline has not passed, ensure that the boiler or process heater meets applicable compliance requirements on or before the deadline(s). The following are suggestions for evaluating the compliance status of a boiler or process heater:

- First, check to see if a Notice of Initial Compliance has been completed and submitted to the Administrator (this notice is the final step in the initial compliance process and strongly indicates the boiler or process heater has completed the initial compliance requirements). If a Notice of Initial Compliance (and in some cases, semi-annual or annual compliance reports have been submitted as well) has been properly completed and submitted, continuing compliance is indicated. Review the continuous compliance requirements (periodic tune-up schedule, etc.) and ensure all obligations are being met.
- If a Notice of Initial Compliance has not been filed for the boiler or process heater in question, verify that a Notice of Applicability has been filed with the Administrator.
- Locate records to determine the date and scope of any tune-up, energy assessment, performance testing, and fuel analysis that may or may not have been conducted on the boiler or process heater. Compare these records with the initial and continuous (on-going) compliance requirements to determine which, if any, requirements are lacking.

3.2 Compliance Requirement Summary

Boiler MACT requirements are based on the fuel type, the age, the size, frequency of use (limited or not), and the design of the boiler or process heater. The requirements, depending on certain boiler or process heater characteristics, include tune-ups, energy assessments, start-

up/shut-down procedures, operating limits, emission limits, and monitoring. The following table summarizes the general compliance requirements from Table 1, Table 2, and Table 3 of Subpart DDDDD:

Table 3-1. General Compliance Requirements

Boiler MACT Compliance Requirements by Fuel Type (Summarized from Table 1, Table 2, and Table 3 from 40 CFR 63, Subpart DDDDD)					
Boiler/Process Heater Factors for Compliance Requirements		General Compliance Requirements (Applies to New and Existing Units Unless Otherwise Noted)			
Heat Input Capacity (MMBtu/hr)	Fuel Type	Tune-Up Schedule* (Initial Tune-up Required for Existing Units)	One-Time Energy Assessment	Startup & Shutdown Requirements	Emission Limits
≤ 5	Gas 1	Every 5 Years	Existing Units Only	None	None
	Gas 2				
	Light Liquid				
≤ 5	Solid Fuel	Every 2 Years	Existing Units Only	None	None
	Heavy Liquid				
>5 and <10	Gas 1				
	Gas 2				
	Solid Fuel				
	Light Liquid				
	Heavy Liquid				
≥ 10	Gas 1	Every Year	Existing Units Only	None	None
≥ 10	Gas 2	Every Year	Existing Units Only	Yes	HCL, PM, Mercury, CO
	Solid Fuel				
	Light Liquid				
	Heavy Liquid				
All	All Fuel Types, Limited Use	Every 5 Years	Not Required	None	None
*Boilers and Process Heaters with an Oxygen Trim System require a Tune-Up every 5 years.					

3.2.1 Compliance Deadlines

All compliance deadlines have passed. All newly installed Boiler and process heaters must be in compliance upon start-up. **If it is determined that the facility did not meet an applicable deadline for a boiler or process heater, immediately contact the AFCEC/CZTQ Air Quality Subject Matter Expert for a consult on developing a compliance strategy.**

The following table summarizes the initial compliance deadlines for Boiler MACT:

Table 3-2. Initial Compliance Deadlines.

Boiler MACT Initial Compliance Deadlines				
For Units Constructed or Reconstructed...	The following needs to be completed on or before the following dates....			
	Tune-up	Energy Assessment	Performance Test (Stack Testing, Fuel Analysis, and CMS Evaluation)	Notification of Compliance Status
Between 4 June 2010 and 1 April 2013	1 April 2013 Passed	Not Required	30 July 2013 Passed	60 th day following the completion of all initial compliance demonstrations for all boilers or process heaters at the facility
After 1 April 2013	Upon Startup	Not Required	180 days after Startup	
On or before 4 June 2010	31 January 2016 Passed		29 July 2016 Passed	

3.2.1.1 Boilers and Process Heaters that Switch Subcategories within Boiler MACT

- If a fuel switch or physical change to an existing boiler or process heater results in the applicability of a different subcategory after 31 January 2016, the unit must be in compliance with the applicable existing source provisions of that subcategory on the effective date of the fuel switch or physical change. Compliance must be demonstrated within 60 days of the switch or change unless compliance has been demonstrated for the new subcategory within the previous 12 months. [§63.7495(h) and §63.7510(k)]
- If a fuel switch or physical change to a new boiler or process heater results in the applicability of a different subcategory, the unit must be in compliance with the applicable new source provisions of that subcategory on the effective date of the fuel switch or physical change. Compliance must be demonstrated within 60 days of the

switch or change unless compliance has been demonstrated for the new subcategory within the previous 12 months. [§63.7495(i) and §63.7510(k)]

For both new and existing boilers and process heaters switching subcategories, a notice must be provided within 30 days of the date of the switch/change. The notification must identify [§63.7545 (h)(1-3)]:

- The name of the owner or operator of the affected source, as defined in §63.7490, the location of the source, the boiler(s) and process heater(s) that have switched fuels, were physically changed, and the date of the notice.
- The currently applicable subcategory under this subpart.
- The date upon which the fuel switch or physical change occurred.

3.2.1.2 Boilers and Process Heaters that Become Subject to Boiler MACT

Area Sources that become a Major Source –

If an Area Source increases emissions or PTE (or no longer has Synthetic Area Source status) such that it becomes a Major Source of HAPs:

- Any new or reconstructed boiler or process heater at the existing source must be in compliance with Subpart DDDDD upon start-up [§63.7495(c)(1)].
- Any existing boiler or process heater at the existing source must be in compliance with Subpart DDDDD within three years after becoming a Major source of HAP [§63.7495(c)(2)].
- If an existing EGU becomes subject to Boiler MACT after 31 January 2016, the unit must be in compliance with the applicable existing source provisions of Boiler MACT on the effective date such unit becomes subject to Boiler MACT. Compliance must be demonstrated within 180 days after becoming an affected source [§63.7495(f) and §63.7510(i)].
- If a boiler or process heater would be subject to Boiler MACT except for an exemption in §63.7491(i) and becomes subject to Boiler MACT after 31 January 2013 due to no longer being exempt, such boiler or process heater must be in compliance with the applicable existing source provisions within three years after the unit becomes subject to Boiler MACT [§63.7495(g)].
- If the boiler or process heater would be subject to Boiler MACT except for the exemption for commercial and industrial solid waste incineration units covered by Part 60, Subpart

CCCC or subpart DDDD, and that boiler or process heater ceases combusting solid waste after the initial compliance date has passed, the boiler or process heater must be in compliance with Boiler MACT beginning on the effective date of the switch from waste to fuel and will no longer be subject to Part 60, Subparts CCCC or DDDD. Compliance must be demonstrated within 60 days of the effective date of the waste-to-fuel switch, if the compliance demonstration for Boiler MACT was not conducted within the previous 12 months. All compliance demonstrations for Boiler MACT must be conducted before commencing/recommencing combustion of solid waste [§63.7495(e) and §63.7510(h)].

- If commencing or recommencing combustion of solid waste is intended, 30-days prior notice of the date combustion of solid waste will be commenced or recommenced must be provided. The notification must identify [§63.7545(g)]:
 - 1) The name of the owner or operator of the affected source, the location of the source, the boiler(s) or process heater(s) that will commence burning solid waste, and the date of the notice.
 - 2) The currently applicable subcategories under Boiler MACT.
 - 3) The date on which the boiler or process heater became subject to the currently applicable emission limits.
 - 4) The date which combusting solid waste will commence.

3.2.1.3 Boilers and Process Heaters that are no Longer Subject to Boiler MACT

Major Sources that become an Area Source –

NOTE: Requirements for Major Sources of HAPs that become an Area Source of HAPs are subject to significant change due to legal contests; contact AFCEC/CZTQ for guidance.

On 25 January 2018, the EPA signed a memorandum stating that once a Major Source of HAPs becomes an Area Source of HAPs, the source is no longer subject to Major Source requirements (including Subpart DDDDD). This memorandum removed a previous policy (referred to as “Once In, Always In”), dated 16 May 1995, which stated that if a facility is a Major Source of HAPs on the “first compliance date” of a relevant Major Source standard, the facility is required to comply permanently with that standard. The first compliance date is the first date a source must comply with a substantive requirement such as emission limits (not Initial Notification).

3.2.2 Extension of Compliance Deadlines

Facilities proactively pursuing compliance in “good faith” may request an extension up to one-year if needed, depending on the circumstances of the request. For example, if the facility needs additional time for the installation of controls or to replace an old boiler or process heater then an extension may be requested. The extension requests are reviewed on a case-by-case basis and

are not automatically granted. Progress reports under an extension of compliance is required. To request the extension, submit a written request to the proper administrator or local air permitting authority with the explanation for the extension no later than 120 days prior to compliance date. The request for an extension must include the following information at a minimum [40 CFR §63.6(i)(4)(i)(A) & (B)]:

- Description of controls to be installed to comply with the standard (or detailed description regarding the reason for the extension request).
- Compliance schedule, including dates each step toward compliance will be reached, including:
 - Date by which on-site construction, installation of emission control equipment, or process change is planned to be initiated.
 - Date by which final compliance is to be achieved.
- Current Compliance Status.

The Administrator must notify the facility in writing of the extension approval or denial (or intent to deny request) within 30 calendar days after receipt of the extension request. If approved, the extension may be terminated early by the Administrator if the compliance schedule is not met.

NOTE: Until an extension of compliance has been granted by the Administrator, the owner or operator of an affected source subject to a Part 63 standard shall comply with all applicable requirements of that standard [§63.6(i)(1)].

3.3 Requirement and Task Overview

Boiler MACT is a complex rule. To assist in compliance with Boiler MACT, this Guide breaks up the primary requirements into sections and Tasks:

Submit Initial Notification of Applicability

Initial Compliance with Work Practice Standards

- Task 1: Conduct Initial Tune-Ups
- Task 2: Conduct One-Time Energy Assessment
- Task 3: Utilize Startup and Shutdown Work Practices

Initial Compliance with Emission Limits

- Task 1: Consider Compliance Strategies
- Task 2: Develop Compliance Plans
- Task 3: Comply with Initial Test/Evaluation Notification Requirements
- Task 4: Determine Emission Limits for Boiler or Process Heater
- Task 5: Conduct Initial Performance Tests

Task 6: Conduct Fuel Analysis

Task 7: Establish Operating Parameters during Performance Test

Task 8: Conduct Performance Evaluations of Continuous Monitoring Systems

Task 9: Submit Notification of Compliance Status

Continuous Compliance

Task 1: Continue Work Practices

Task 2: Conduct Periodic Tune-Ups

Task 3: Continue Startup and Shutdown Practices

Task 4: Conduct Periodic Performance (Stack) Testing

Task 5: Conduct Periodic Fuel Analysis

Task 6: Monitor and Collect Data

Submit Notifications and Reports as Required

Satisfy Recordkeeping Requirements

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4 INITIAL COMPLIANCE WITH BOILER MACT

4.1 Submit Initial Notification of Applicability

The Initial Notification of Applicability is the first requirement for compliance with Boiler MACT. The Notification is required by the EPA to convey if a facility is a Major Source or an Area Source and provides general information regarding each boiler and process heater located at the facility.

Notification Date for Existing Sources

If the start-up of an existing boiler or process heater was before 31 January 2013, the deadline for Initial Notification of Applicability was 31 May 2013.

- If start-up is on or after 31 January 2013, then the notification is due within 15 days after the actual start-up [§63.7545(c)].

Notification Date for New Sources

The notification date is 31 January 2013 or within 15 days after start-up of a new source, whichever is later. New or Reconstructed Sources may also be required to submit the following Notifications:

- Notification to Construct [§63.9(b)(4)].
- Notification of Actual Startup must be submitted within 15 days after start-up.

Complete and submit the Initial Notification of Applicability to the appropriate Administrator. Many agencies have forms available on their websites (including EPA). Initial Notifications must include the following information at a minimum [§63.9(b)(2)]:

- The name and address of the owner or operator;
- The address (i.e., physical location) of the affected source;
- A statement of whether the affected source is a major source or an area source;
- An identification of the relevant standard, or other requirement, that is the basis of the notification and the source's compliance date; and
- A brief description of the nature, size, design, and method of operation of the source and an identification of the types of emission points within the affected source subject to the relevant standard and types of hazardous air pollutants emitted.

4.2 Initial Compliance with Work Practice Standards

4.2.1 Task 1: Conduct Initial Tune-ups and Inspections

Initial Compliance Date for Existing Units - Initial tune-ups must have been completed by 31 January 2016. If an existing boiler or process heater was not in operation on this date, a tune-up must be completed within 30 days after restarting.

NOTE: New boilers and process heaters are **NOT** required to conduct an initial tune up. It is assumed that the majority of new or reconstructed boilers and process heaters are properly tuned at start-up and are within compliance. For new and reconstructed boilers and process heaters, the first tune-up must be no later than 13 months (if annual tune-up is required), 25 months (if biennial tune-up is required), or 61 months (if 5-year tune-up is required) after initial start-up [§63.7515(d)].

Special Considerations for Tune-Ups (Table 3 to 40 CFR 63, Subpart DDDDD)

- A new or existing boiler or process heater with a continuous oxygen trim system that maintains an optimum air to fuel ratio will only require a tune-up every five years, regardless of fuel classification or size.
- Units in either the Gas 1 or Metal Process Furnace subcategories will conduct this tune-up as a work practice for all regulated emissions under this subpart. Units in all other subcategories will conduct this tune-up as a work practice for dioxins/furans.
 - *Metal process furnaces* are a subcategory of process heaters which include natural gas-fired annealing furnaces, preheat furnaces, reheat furnaces, aging furnaces, heat treat furnaces, and homogenizing furnaces.

Tune-Up and Inspection Requirements

The primary goal of a boiler or process heater tune-up is to improve efficiency with respect to combustion operations. Improving combustion efficiency reduces fuel usage resulting in decreased emissions. For example, if coal is not completely burned during combustion, carbon becomes part of PM which will then require management by other methods downstream in the process (control devices, etc.). Additionally, a thorough inspection can also reveal problems such as an improper air-to-fuel ratio or a compromised furnace seal which can lead to high levels of CO emissions. This is particularly important for older models of boilers and process heaters because they are typically not designed to achieve low CO levels.

Although tune-ups are normally considered to be standard maintenance for boilers and process heaters, requirements in Boiler MACT exceed what is normally considered to be a “tune-up”.

The tune-up and inspection generally consists of, at a minimum, the following items [40 CFR 63.7540(a)(10) and (13)]:

- The tune-up must be conducted while burning the fuel that provided the majority of the heat input to the boiler in the last 12 months before the tune-up (or fuels if the boiler burns a mixture).
- Inspect the burner, and clean or replace any components of the burner as necessary (this inspection can be performed any time prior to tune-up or can be delayed until the next scheduled unit shut-down, but each burner must be inspected at least once every 36 months).
- Inspect the flame pattern, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available.
- Inspect the system controlling the air-to-fuel ratio, and ensure that it is correctly calibrated and functioning properly (this inspection can be delayed until the next scheduled unit shut-down if needed).
- Optimize total emissions of carbon monoxide. This optimization should be consistent with the manufacturer's specifications, if available, and with any nitrogen oxide requirement.
- Measure the concentrations in the effluent stream of carbon monoxide in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made).
- Maintain onsite and submit, if requested by the Administrator, the annual, biennial, or five-year report (as applicable to the unit's tune-up schedule) containing the following information:
 - The concentrations of CO in the effluent stream in parts per million, by volume, and oxygen in volume percent, measured before and after the tune-up of the boiler.
 - A description of any tune-up corrective actions taken.
 - The type and amount of fuel used over the 12 months prior to the tune-up of the boiler, but only if the unit is physically and legally capable of burning more than one fuel.

4.2.2 Task 2: Conduct One-Time Energy Assessment

NOTE: The compliance date for energy assessments has passed. This section is retained for informational purposes.

Existing boilers and process heaters (with the exception of Limited Use boilers and process heaters) must undergo a formal one-time energy assessment.

Prior Energy Assessments/Programs: A facility that 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 1 January 2008 and 31 January 2016 that includes the affected units also satisfies the energy assessment requirement. Energy assessor approval and qualification requirements are waived by the EPA in instances where past or amended Energy Assessments are used to meet the Energy Assessment requirements. *The Base Civil Engineer will determine if the prior assessment or energy management program meets the Energy Assessment substitution criteria before the Notification of Compliance is submitted to the EPA.*

The energy assessment must be conducted by a qualified energy assessor and includes an audit of the boiler or process heater system (components, combustion air systems, fuel systems, etc.) as well as systems using energy produced by the boiler or process heater, such as facility heating, ventilation, and air conditioning (HVAC) systems; hot heater systems; compressed air systems; process heating and cooling, and lighting. Assessments entail, but are not limited to, the following [40 CFR 63.7510(e) and (j) and Table 3 of Subpart DDDDD]:

- A visual inspection of the boiler system;
- An evaluation of operating characteristics of the boiler systems, specifications of energy using systems, operating and maintenance procedures, and unusual operating constraints;
- An inventory of major energy use systems consuming energy from affected boilers, which are under the control of the boiler operator;
- A review of available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage;
- A review of the facility's energy management programs and recommendations for improvements consistent with the definition of energy management programs, if identified;
- A list of cost-effective energy conservation measures that are within the facility's control;
- A list of the energy savings potential of the energy conservation measures identified; and
- A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping these investments.

Qualified Energy Assessor –

The Qualified Energy Assessor can be internal or a third-party. The person is required to possess demonstrated capabilities to evaluate energy savings opportunities for steam generation and major energy using systems, including, but not limited to: boiler combustion management, boiler

thermal energy recovery, boiler blowdown thermal energy recovery, primary energy resource selection, insulation issues, etc. The Qualified Energy Assessor should have, at a minimum, the background, experience, and recognized abilities to perform the required assessment activities, data analysis, and report preparation (§63.7575).

Duration and Scope of Energy Assessment -

Table 4-1, *Energy Assessment Duration and Scope*, summarizes the duration and scope of the energy assessment per the requirements of Boiler MACT. There are no minimum hours required for the energy assessment, but the assessment must include all components required by Subpart DDDDD. However, there is a cap on how many on-site technical labor hours can be expended on the energy assessment (the maximum on-site technical hours may be exceeded at the discretion of the operator or owner). The maximum technical hours are based on combined heat input calculations. To determine which heat input capacity thresholds and associated maximum on-site technology labor hours apply to the Energy Assessment, the “combined heat input” is calculated by adding together the heat input capacity for each boiler subject to the Energy Assessment requirement as further described below:

- Facility heat input capacity is calculated by adding together the heat input capacity for each boiler subject to the Energy Assessment requirement (existing boilers and process heaters except for Limited-Use).
- The combined heat input capacity is a measurement of the facility’s total boiler and process heater capacity measured in Trillion British thermal units per year (TBtu/yr).
- Heat input capacity for each boiler or process heater subject to the Energy Assessment is calculated based on 8,760 hr/yr, then added together.

The combined heat input capacity of the facility is also used to determine the minimum percentage of the on-site energy use system that is required to be evaluated. For example, a facility with a combined heat input capacity of less than 0.3 trillion BTU/yr, will be required to have the boiler system and any on-site energy use systems accounting for at least 50% of the affected boiler’s energy (e.g., steam, hot water, or electricity) production included in the assessment, within the limit of the 8-hour maximum on-site technical labor hours. If the facility does not have any on-site energy use systems that account for at least 50% of the boiler’s energy production, then only the boiler needs to be evaluated to identify energy savings opportunities.

To determine the scope of the energy assessment, each on-site energy use system is examined separately to determine how much of the boiler’s energy production it uses. The on-site energy use systems serving as the basis for the percent of affected boiler(s) and process heater(s) energy production may be segmented by production area or energy use area as most logical and applicable to the specific facility being assessed (e.g., product X manufacturing area; product Y drying area; Building Z). The boiler system(s), process heater(s), and any on-site energy use

system(s) accounting for at least the percentage of the energy (e.g., steam, process heat, hot water, or electricity) production, as applicable, are required to be evaluated to identify energy savings opportunities.

NOTE: On-site energy use system(s) means any individual energy use system, not combination of energy use systems, accounting for the specified amount of the affected boiler energy.

Table 4-1. Energy Assessment Duration and Scope

If the Facility has Affected Boilers and Process Heaters with a Combined Heat Input Capacity of...	The Maximum On-Site Technical Labor Hours is..	The Minimum Percentage of the Boiler or Process Heater's On-Site Energy Use System to be Evaluated is...
< 0.3 Trillion Btu year (TBtu/yr)	8 Hours	50% of boiler(s) energy output
> 0.3 TBtu & < 1.0 TBtu/yr	24 Hours	33% boiler(s) energy output
> 1.0 TBtu/yr	24 hours + 8 hours per additional 1.0 TBtu/yr (not to exceed 160 hours)	20% boiler(s) energy output
40 CFR §63.11237		

Energy Assessment Report

A report will be prepared by the assessor identifying energy conservation measures and opportunities, and establishing costs and simple payback on investments, compared to potential energy savings. Although there is no requirement in Boiler MACT for facilities to follow the recommendations in the energy assessment report, the assessment can be a valuable tool. For facilities interested in pursuing credit for implementing energy conservation measures identified in the energy assessment, the energy assessment will establish benchmarks for comparison. Also, Energy Assessments can be used to determine whether or not affected boilers and process heaters are capable of meeting emission limits; therefore, the assessment can serve as an instrument for identifying retrofits, upgrades, and other options that may be necessary to achieve compliance.

4.2.3 Task 3: Follow Start-up and Shut-down Work Practices and Procedures

This Task applies to large boilers and process heaters that are subject to emission limits (Units that combust Coal, Biomass, Gas 2, and Liquid Fuel that are not Limited Use).

NOTE: A newly installed boiler or process heater should be tested to ensure that the unit and all associated components are properly installed and will operate as designed (“pre-start-up” activities). The EPA does not intend for the start-up period to begin when newly installed unit’s

first fire fuel for testing or other pre-start-up purposes because such firing of fuel does not represent normal operation of the unit.

During start-up and shut-down, it is impracticable to measure emissions and the safe operation of certain pollution control devices is not possible. For that reason, the facility must comply with all applicable emissions limits at all times *except for* start-up or shut-down periods. To reduce emissions of pollutants during those periods, Boiler MACT provides work practices for boilers and process heaters subject to emission limits and clarifies when “start-up” and “shut-down” occurs. At the core of the start-up and shut-down work practices and definitions are the terms “clean fuels” and “useful thermal energy”.

Useful thermal energy - The EPA’s definitions of start-up and shut-down includes the concept of “useful thermal energy”, which recognizes that small amounts of steam or heat may be produced when starting up a unit, but the amounts would be insufficient to operate processing equipment and safely initiate pollution controls. Useful thermal energy means energy (i.e., steam, hot water, or process heat) that meets the minimum operating temperature, flow, and/or pressure required by any energy use system that uses energy provided by the affected boiler or process heater.

Clean Fuels - For start-up of a boiler or process heater, one or a combination of the following clean fuels must be used (any fuel meeting the appropriate HCl, Hg, and TSM emission standards by fuel analysis can also be used):

- Natural gas
- Synthetic natural gas
- Propane
- Distillate oil
- Syngas
- Ultra-low sulfur diesel
- Fuel-oil soaked rags
- Clean dry biomass*
- “Other” Gas 1
- Kerosene
- Hydrogen
- Paper
- Cardboard
- Refinery gas
- Liquefied petroleum gas

*Clean dry biomass means any biomass-based solid fuel that has not been painted, pigment-stained, or pressure treated, does not contain contaminants at concentrations not normally associated with virgin biomass materials, has a moisture content of less than 20 percent, and is not a solid waste.

SAFETY FIRST! Optimally, boilers and process heaters are subject to emission limits after steady-state conditions are achieved (safe and stable operating conditions are reached and emissions controls are properly operating). The procedures to safely complete a start-up and the time necessary to reach stable operating conditions when transitioning from start-up (clean) fuels can vary by the boiler or process heater’s fuel, design, and pollution control devices. Startup procedures must ensure that the equipment is brought up to normal operating conditions in a safe manner using

procedures as recommended by the equipment vendor/manufacturer and as required by codes for the prevention of explosions and fires. Typically, many air pollution control devices cannot be safely engaged during start-up. For example, oxygen levels are typically high during start-up, so the Electrostatic Precipitator (ESP) should not be engaged until stable operating conditions are reached. Premature start-up of an ESP can lead to unsafe conditions, such as a fire. For this reason, safety measures are frequently included in the standard operating procedures and industry standard practices for the device (some ESPs have safety mechanisms that shut down the ESP when sensors detect high flue gas oxygen levels). Definition 2 of start-up allows one-hour from the first firing of unclean fuels before PM controls, such as ESP, must be engaged; however, that may not be adequate time for some units. If a PM control is not able to be safely engaged within one-hour of firing “unclean” fuels, EPA allows time extensions which are approved on a case-by-case basis [as specified in §63.7555(d)(13)]. To expedite the approval process, the EPA delegated the permitting authority (State, local, or Tribal agency) to review and approve the variance, if requested.

Start-up Compliance Options (Definitions) - To address potentially detrimental safety concerns during initiation of certain air pollution control devices as well as negative impacts on equipment, EPA allows facilities to choose between two definitions when complying with start-up requirements. As explained in more detail below, under the alternate definition (Option/Definition 2), start-up ends four hours after the boiler or process heater begins supplying useful thermal energy and PM controls must be engaged within one hour of first feeding non-clean fuels:

Start-up Compliance Option 1 (Definition 1) -

Definition of start-up is either the first-ever firing of fuel in a boiler or process heater for the purpose of supplying useful thermal energy for heating and/or producing electricity, or for any other purpose, or the firing of fuel in a boiler after a shut-down event for any purpose. Start-up ends when any of the useful thermal energy from the boiler or process heater is supplied for heating, and/or producing electricity, or for any other purpose.

If the facility elects to comply using Definition 1 of “start-up”:

- One or a combination of clean fuels must be used during start-up.
- All Continuous Monitoring Systems (CMS) must be operated during start-up.
- Once the boiler or process heater starts firing fuels that are not clean fuels, emissions must be vented to the main stack(s) and all applicable control devices must be engaged **with the exception of the following devices**. However, these devices must be engaged as expeditiously as possible after start-up:
 - Limestone Injection in Fluidized Bed Combustion.
 - Dry Scrubber.

- Fabric Filter.
- Selective Catalytic Reduction.
- Monitoring data must be collected during periods of start-up, as specified in §63.7535(b).
- Records must be kept during periods of start-up.
- Reports concerning activities and periods of start-up must be provided, as specified in §63.7555.
- Startup ends when steam or heat is supplied for any purpose.

Startup Compliance Option 2 (Definition 2) -

The EPA's intent was air pollution controls be engaged and operational at the moment the boiler or process heater fires a non-clean fuel; however, many affected units do not have the ability to engage their PM controls so quickly after first firing non-clean fuel. To provide added flexibility for those units, the EPA provides a one-hour period of time following the initiation of firing of non-clean fuels before PM controls must be engaged under this definition. Additionally, to clarify that the work practices do not supersede any other standard or requirements (new source performance standards, state regulations, etc.), the EPA included a provision that requires control devices to operate when necessary to comply with other standards.

Under Definition 2, start-up is the period during 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 shut-down event. Startup ends four hours after the boiler or process heater supplies useful thermal energy (such as heat or steam) for heating, cooling, or process purposes, or generates electricity, whichever is earlier.

If the facility elects to comply using Definition 2 of "start-up":

- One or a combination of clean fuels must be used during start-up.
- All CMS must be operated during start-up.
- Once the boiler or process heater starts to be fed fuels that are not clean fuels, emissions must be vented to the main stack(s).
- All applicable control devices must be engaged so as to comply with the emission limits within four-hours of start of supplying useful thermal energy.
- All applicable control devices must be started as expeditiously as possible, but, in any case, when necessary to comply with other standards applicable to the source by a permit limit or a rule other than this subpart that require operation of the control devices.

- PM controls must be engaged and operated within one hour of first feeding fuels that are not clean fuels.
- The EPA allows a source to request a case-by-case extension to the one-hour period for engaging the PM controls based on evidence of a documented manufacturer identified safety issue and proof that the PM control device is adequately designed and sized to meet the filterable PM emission limit. It is acknowledged that there may be another control device that has been installed other than ESP that provides additional PM control (e.g., scrubber). If not able to safely engage and operate PM control(s) within one hour of first firing of non-clean fuels, the facility may choose to rely on definition (1) of “start-up” or submit to the Administrator a request for a variance with the PM controls requirement, as described below:
 - The request shall provide evidence of a documented manufacturer-identified safety issue.
 - The request shall provide information to document that the PM control device is adequately designed and sized to meet the applicable PM emission limit.
 - In addition, the request shall contain documentation that:
 - The unit is using clean fuels to the maximum extent possible to bring the unit and PM control device up to the temperature necessary to alleviate or prevent the identified safety issues prior to the combustion of primary fuel;
 - The unit has explicitly followed the manufacturer’s procedures to alleviate or prevent the identified safety issue; and
 - Identifies with specificity the details of the manufacturer’s statement of concern.
- A written Startup and Shutdown Plan (SSP) must be developed and implemented according to the requirements in Table 3 of Subpart DDDDD. The SSP must be maintained onsite and available upon request for public inspection.
- Monitoring data must be collected during periods of start-up, as specified in §63.7535(b).
- Records must be kept during periods of start-up.
- Reports concerning activities and periods of start-up must be provided, as specified in §63.7555.
- Facilities demonstrating compliance using Definition 2 will be required to meet enhanced recordkeeping provisions.

Work Practices during Shutdown –

Shutdown is the period in which cessation of operation of a boiler or process heater is initiated for any purpose. Shutdown begins when the boiler or process heater no longer supplies useful thermal energy (such as heat or steam) for heating, cooling, or process purposes and/or generates electricity or when no fuel is being fed to the boiler or process heater, whichever is earlier. Shutdown ends when the boiler or process heater no longer supplies useful thermal energy (such as steam or heat)

for heating, cooling, or process purposes and/or generates electricity, and no fuel is being combusted in the boiler or process heater. Work Practices during shut-down include (§63.7575 and Table 3 of Subpart DDDDD):

- All CMS must be operated during shut-down.
- While firing fuels that are not clean fuels during shut-down, emissions must be vented to the main stack(s) and all applicable control devices must be engaged **with the exception of the following devices** but, in any case, when necessary to comply with other standards applicable to the source that require operation of the control device:
 - Limestone Injection in Fluidized Bed Combustion.
 - Dry Scrubber.
 - Fabric Filter.
 - Selective Catalytic Reduction.
- If, in addition to the fuel used prior to initiation of shut-down, another fuel must be used to support the shut-down process, that additional fuel must be one or a combination of the following clean fuels: natural gas, synthetic natural gas, propane, other Gas 1 fuels, distillate oil, syngas, ultra-low sulfur diesel, refinery gas, and liquefied petroleum gas.
- Monitoring data must be collected during periods of shut-down, as specified in §63.7535(b).
- Records must be kept during periods of shut-down.
- Reports must be provided concerning activities and periods of shut-down, as specified in §63.7555.

4.3 Initial Compliance with Emission Limits

NOTE: Emission limits apply ONLY to large boilers and process heaters which Combust Coal, Biomass, Gas 2, and Liquid Fuel (and are not Limited Use).

An emission limit is a permissible quantity of a particular HAP (or surrogate) that may be emitted from the boiler or process heater over a specific time frame and is not to be exceeded. Boilers and process heaters that **DO NOT** have emission limits include:

- Small (<10 MMBtu/hr) boilers and process heaters.
- Boilers and process heaters in the Gas 1 Subcategory (natural gas, refinery gas, and gases that qualify as “other Gas 1”).

- Limited-use boilers and process heaters.

Instead of establishing emission limits for each and every regulated HAP, the EPA frequently uses surrogates. The surrogate pollutants have similar post-combustion characteristics to the original HAP(s). Boiler MACT sets emission limits for the following pollutants (and surrogates):

Fuel-based pollutants (direct result of the contaminants in fuels combusted):

- Mercury (Hg).
- Filterable PM or Total Selected Metals (TSM) - Surrogate for all non-mercury metallic HAPS. TSM is the sum of arsenic, beryllium, cadmium, chromium, lead, manganese, nickel and selenium. In some cases, PM would not be an appropriate surrogate for metallic HAP. Therefore, an alternative metals emission limit is included.
- Hydrogen chloride (HCl) - Surrogate for acid gas HAPs.

Combustion-based pollutants:

- Carbon Monoxide (CO) – Surrogate organic air toxics (non-dioxin/furan).
- Dioxin and Furan – These pollutants do not have emission limits; they are regulated through work practices such as tune-ups.

NOTE: PM is a combustion-based pollutant for liquid and biomass fuels and a fuel-based pollutant for coal/solid fossil fuels.

The following tables in Boiler MACT work in conjunction with each other for initial and continuous compliance with emission limits:

- Table 1 to Subpart DDDDD – contains the emission limits for new or reconstructed boilers and process heaters.
- Table 2 to Subpart DDDDD – contains the emission limits for existing boilers and process heaters.
- Table 4 to Subpart DDDDD (summarizes §63.7500) - contains the operating limit parameters for each applicable control equipment used for compliance to the emission limits.
- Table 5 to Subpart DDDDD - (summarizes §63.7520) contains the Performance Testing requirements.

- Table 6 to Subpart DDDDD – (summarizes §63.7521) contains the Fuel Analysis Requirements.
- Table 7 to Subpart DDDDD (summarizes §63.7520) - specifies requirements for establishing operating parameters during the Performance Test.
- Table 8 to Subpart DDDDD (summarizes §63.7540) - contains the requirements for demonstrating continuous compliance with the Emission Limitations for each boiler or process heater.

4.3.1 Task 1: Develop Compliance Strategies

To demonstrate initial compliance with emission limits, the following must be completed on a pollutant-by-pollutant basis, depending on the compliance option elected or required:

- Conduct initial performance (stack) tests for: PM (or alternatively TSM), CO, HCl, or Hg.
 - As an alternative to performance stack testing for Hg, HCl, or TSM, a fuel analysis may be conducted to demonstrate that the fuel pollutant input is lower than the applicable emission limit.
- Conduct initial fuel analysis – The fuel or mixture of fuels with the highest emissions potential for chlorine, Hg, and/or TSM must be combusted during the performance test. A fuel analysis is required for multiple-fueled boiler and process heaters. Fuel analysis is not required for a single fueled boiler unless continuing compliance will be based on fuel analysis.
- Continuous Emissions Monitoring Systems (CEMS) – Boilers and process heaters that use CEMS are exempt from initial CO performance testing, fuel analysis, and oxygen operating limit.
 - Any boiler or process heater that has a CO CEMS that is compliant (i.e., certified) with Performance Specification 4, 4A, or 4B at 40 CFR Part 60, Appendix B must use the CO CEMS to comply with the applicable alternative CO CEMS emission standard.
- Establish operating limits during the performance test.
- Conduct performance evaluations of CMS.
- Monitor and collect data to demonstrate compliance with the operating limits.

It is important to have a well-thought out approach for compliance with Boiler MACT's emission and operating limits. Every boiler, process heater, and facility is unique. Various options should be

considered and evaluated to decide the best approach for initial and continuous compliance based on the particular circumstances of the boiler, process heater, and facility. Preliminary testing is helpful in assessing the compliance status of the boiler or process heater and for determining the best compliance approach on a pollutant by pollutant basis. Usually, notifications for performance (stack) testing conducted for the facility's own purposes, such as engineering studies or tests to develop and evaluate alternative methods, does not need to be submitted to the Administrator. However, the data from such tests may be subject to Title V reporting requirements, if applicable. If the facility wishes to use the test results for future compliance purposes, the test must be performed using the same approved methods and other requirements contained within Boiler MACT.

Boiler MACT allows for some flexibility in meeting emission limits, which is one of the reasons the rule is so complex. There are a number of alternatives and compliance options to consider if the boiler or process heater can not meet Boiler MACT emission limits based on current fuel type combusted, design, and operational limitations. In developing a compliance strategy, there are various options to consider, including the following:

- Using a CEMS for PM, Hg, HCl, and CO will avoid the need for fuel analysis or performance test for that pollutant.
- Carbon Dioxide may be used as an alternative to using oxygen in correcting the measured CO CEMS data without petitioning for an alternative monitoring procedure.
- Elect to comply with Hg, HCl, or TSM limits by fuel analysis instead of performance stack-testing (fuel analyses can't be used for gaseous fuels to comply with the TSM or HCl standards).
- Operate a dual-fueled boiler on natural gas or a fuel that qualifies as "Gas 1" (no emission limits will be required). Add natural gas capability to an existing boiler, if possible.
- Modify combustion controls and the fuel feed design or system.
- Co-fire just enough natural gas to meet MACT limits.
- Install add-on pollution controls to meet requirements.
- Using the TSM alternate limit instead of the PM limit (either a PM CEM or a Continuous Parametric Monitoring System (CPMS) is required for coal and heavy liquid-fired units larger than 250 MMBtu/hr unless the TSM limit is elected to demonstrate compliance).
- A boiler or process heater in the Unit Designed to Burn Light Liquid subcategory can combust ultra-low sulfur liquid fuel to avoid further performance testing after the initial performance test.

- An SO₂ CEM can be used if using a wet scrubber or dry sorbent injection to comply with the HCl limit.
- Elect to comply with the alternate CO CEMS-based limit instead of the CO stack based limit. (Stokers/sloped grate/others designed to burn kiln-dried biomass fuel, fuel cell units designed to burn biomass/bio-based solids, liquid fuel and Gas 2 fired units do not have the option).
- Emissions averaging (for existing boilers only and requires output-based limits).
- Do energy projects and take advantage of output-based limits (Energy/Efficiency credits for existing boilers only. Requires output-based limits).

4.3.1.1 Air Pollution Control and Monitoring Technology/Devices

This section provides a basic description for some of the more common air pollution control and monitoring technology available for compliance with Boiler MACT. Frequently, these technologies may already be utilized by the boiler or process heater to comply with permit requirements or other regulations. Although some of these technologies can be used for more than one pollutant, this Guide will focus only on the pollutants/HAPs of concern for compliance with Boiler MACT.

Air Pollution Control Devices -

In some cases, pollutant emissions can be sufficiently reduced through process modifications and combustion controls (change in fuel, good operating practices, etc.). However, in many situations, some form of add-on air pollution control technology is required to meet emission limits. The equipment eliminates, reduces, or transforms pollutants before discharging the exhaust into ambient air. The selection of the appropriate control technology is determined by the targeted pollutant, the boiler or process heater conditions, and the control efficiency required. In some situations, a series of devices are needed to obtain desired emission reduction for the pollutant(s) of concern. For example, a wet scrubber combined with another type of particulate removal device, such as a baghouse or ESP can be used for adequate control of PM. Additionally, sorbents and/or carbons can be injected to neutralize acid gas or capture mercury.

Certain key indicators of system performance, such as flow rate or pressure drop, depending on the device being used, demonstrate that the device is operating properly for adequate control of emissions/pollutant. These indicators (frequently referred to as parameters) must be monitored and measured per the requirements in Boiler MACT. A CPMS monitors, collects, and supplies parameter data to demonstrate compliance. On a pollutant basis, the following air pollution control devices and associated parameters are commonly used and are included within Boiler MACT:

Compliance with PM Emission Limit (boiler/process heater not using a PM CPMS)

- Wet scrubber for PM
 - Parameters to be monitored: Scrubber pressure drop and flow rate.
- Electrostatic precipitator with wet scrubber (also known as Wet ESP or WESP)
 - Parameters to be monitored: Secondary voltage and current.
- Fabric Filter (also known as “Baghouse”)
 - Maintain opacity to less than or equal to 10 percent (daily block average) or the highest hourly average opacity reading measured during the most recent performance test;

OR

- Install bag leak detection system and ensure the bag leak detection system alert is not activated more than 5 percent of the operating time during each 6-month period.

NOTE: If a boiler or process heater does not use a wet scrubber, ESP, or fabric filter to comply with the PM emission limit and if compliance with the PM emission limit is not demonstrated with a CEMS, then a unit must maintain opacity less than or equal to 10% or the highest hourly average opacity reading measured during the most recent performance test.

Compliance with HCl Emission Limit (boiler/process heater not using an HCl CEMS)

- Wet scrubber for HCl
 - Parameters to be monitored: pressure drop, effluent pH, and flow rate.
- Dry scrubber (Sorbent Injection)
 - Minimum sorbent injection rate. If different acid gas sorbents are used during the HCl performance test, the average value for each sorbent becomes the site-specific operating limit for that sorbent.
- If using an acid gas wet scrubber or dry sorbent injection control technology to comply with the HCl emission limit, the use of a sulfur dioxide (SO₂) CEMS can be substituted for the applicable fuel analysis, annual performance test, and operating limits to demonstrate compliance with HCl emissions limit. Use alternate maximum SO₂ emission limit.

Compliance with Hg Emission Limit (boiler/process heater not using an Hg CEMS)

- Dry Scrubber (activated carbon injection)

- Parameters to be monitored: Activated carbon injection rate
- Wet scrubber
 - Parameters to be monitored: Scrubber pressure drop and flow rate.

Compliance with CO Emission Limit (boiler/process heater not using a CO CEMS)

- Oxygen analyzer system
 - Parameters to be monitored: Minimum oxygen level

A brief description of each air pollution control device:

- *Wet Scrubbers* – These devices are capable of collecting, at the same time, gaseous pollutants (acid gases such as HCl) and PM. Although there are a variety of design configurations in use, generally, wet scrubbers capture acid gases (HCl) and/or in liquid droplets by spraying the polluted gas stream with a “scrubbing” liquid (usually water). Wet scrubbers that remove gaseous pollutants are also referred to as absorbers. A high interaction between PM between the gas stream and liquid increases collection efficiency. A method such as placing an electrostatic charge on particles (and droplets) prior to entering the scrubber or atomizing the scrubbing liquid can augment the removal process. Droplets then must be separated from gas stream by another device such as a mist eliminator or entrainment separator. The more liquid droplets captured, the lower the emission levels. The collected droplets dissolve or absorb the particulate matter/pollutant gases which must be treated prior to discharge or reuse. Poorly maintained scrubbers have the potential to spread disease-causing bacteria such as Legionnaires' disease.

A wet scrubber's ability to collect small particles is directly proportional to the power input into the scrubber (increase in nozzle pressure and/or an increase in the liquid-to-gas ratio). Pressure drop occurs as the exhaust gas travels through the scrubber. An increase in pressure drop increases particle collection efficiency. Another important parameter for a wet scrubber is the rate of liquid flow.

- *Dry Scrubber/Carbon Injection System/Sorbent Injection System (dry control)* - A dry sorbent and/or carbon is injected (dry injection) or sprayed (spray dryer) into the exhaust stream to react with acid gas or mercury, forming a dry powder material which is then removed. First, a finely powdered alkaline sorbent, such as lime or sodium bicarbonate, is injected into flue gas (combustion exhaust gas exiting a power plant) where it reacts with and neutralizes acid gases (HCl) and forms a compound. Dry Sorbent Injection treatment for mercury removal is similar, but uses a different sorbent such as powdered activated carbon. The compound is then removed, usually downstream by a PM control device such as an ESP

or Fabric Filter. The injection rate must be sufficient to achieve the required control for the pollutant of concern.

- *Electrostatic Precipitators (wet and dry types)* - An ESP filters suspended fine particles from an airstream by drawing the particles to collection plates with an electric charge; very much the same way that static electricity in clothing picks up small pieces of lint. Transformers are used to develop very high voltage drops between charging electrodes and collecting plates. The electrical field produced in the gas stream introduces a charge on the particles as it passes through the high voltage discharge, which causes the particles to be attracted to the collecting plates. Often, a series of collecting plates are utilized to improve collection efficiency. Periodically, a hammer like device strikes the top of the collecting plates dislodging the particulate to a bottom hopper for removal. If water (or any other fluid) is used for removal of the solid PM, then it is known as a wet ESP.

As a general rule, ESP performance improves as total power input increases. The effectiveness of the ESP in controlling PM emissions from the Boiler can be evaluated based on total power input to the ESP. For that reason, secondary power input (voltage and current) to the ESP is a recognized parameter for controlling emissions of PM. Thus, since the power is the product of the voltage and the current, monitoring power input provides a reasonable assurance that the ESP is functioning properly.

- *Fabric Filters (also called bag houses)* - A fabric filter system efficiently removes particulates by blowing dust-laden air through a compartment(s) containing rows of bags (or other filter media such as a pleated cartridge filter). The structure that houses the system is frequently referred to as a “baghouse”. The cleaned air passes through the fabric and exits the baghouse; similar in operation as a household vacuum cleaner. The cleaned air can be recirculated back into the plant for heating. As dust builds up on the fabric, the dust layer normally improves removal efficiency, up to a certain point, then removal of the accumulated dust level is necessary. Dust is periodically removed by shaking or pulsing the fabric or by blowing air back through the fabric. The dust then falls to a collection hopper where it is removed. Fabrics used for the filters vary and are selected for the particular application (cotton, Teflon, polyester, spun stainless steel, etc.).

A problem inherent in fabric filters is the rupture of the fabric or other similar bag failure. Detecting a leaking bag by direct visual observation can be very difficult, if not virtually impossible. For this reason, instruments are available to monitor changes in particulate emission rates for the purpose of detecting fabric filter bag leaks or similar system failures. The most effective way to monitor and identify bag failure is to install a bag leak detection system equipped with an alarm. The system monitors dust levels while the boiler or process heater is in operation and alarms when those levels exceed a pre-set level. The principles of operation of these instruments include electrical charge transfer and light scattering.

Baghouse leak detectors are installed as indicators of fabric filter performance. The results from the sensor are recorded during a representative period of well-controlled emissions and alarm level is set based on those results. Bag leak detection system means a group of instruments that are capable of monitoring PM loadings in the exhaust of a fabric filter (i.e., baghouse) in order to detect bag failures.

Additionally, an increase in visible stack emissions (opacity) can indicate a bag failure. Opacity measures the quantity of light scattering that occurs as a result of the particles in a gas stream. Opacity can be measured by a transmissometer or by visual observation by a certified visible emission observer using Method 9. Although opacity is not a direct measurement of particle concentration, it is a very good indicator of the amount of dust leaving the baghouse, and consequently provides a performance measure.

Continuous Monitoring Systems

Monitoring of emissions, control device operating parameters, and process operations has been a requirement of many of the emission standards promulgated under the CAA. Basically, the purpose of CMS is to monitor emissions, control device parameters, and process operations, then generate data to demonstrate compliance with Boiler MACT. The measurements can be actual or parametric. Additionally, in most cases, alarms can be set to alert the operator to failures so that corrective action can be taken. CMS) must be properly installed, calibrated, audited, evaluated, and operated to ensure generation of consistent and reliable data on an ongoing basis. Additionally, certain quality assurance and quality control (QA/QC) procedures must be undertaken for compliance and a corrective action in place. There are different types of CMS, including:

- Continuous Parametric Monitoring System (CPMS)
- Continuous Opacity Monitoring System (COMS)
- Continuous Emissions Monitoring System (CEMS)

Continuous Parametric Monitoring System (CPMS) - In general (and as mentioned above), a CPMS monitors and verifies proper process or control device operation on a continuous basis (pressure drop, secondary current, oxygen concentrations, flow rate, etc.), which is then used to assess compliance with Boiler MACT. The parameters measured vary depending on the air control device being used for compliance.

Continuous Opacity Monitoring System (COMS) - A COMS continuously measures opacity (a measure of the amount of light fraction of transmitted light obscured by particles). Opacity often is used as an indicator of the degree of PM emissions. Opacity is usually measured as a percent, where zero percent opacity means completely transparent and 100 percent opacity means completely opaque.

Continuous Emissions Monitoring System (CEMS) - An effective, although frequently cost prohibitive, option to avoid the complexities of performance testing and/or fuel analysis is a CEMS. CEMS provide a high level of accuracy and continuous reporting of emissions. However, a separate performance evaluation is still required to ensure the system is calibrated and operating properly. When complying with the CO emission limit with CEMS, it is important to note that an alternate CO limit will be applicable to the boiler or process heater.

A CEMS collects actual emissions from the boiler or process heater's stack or duct in order to analyze and determine the pollutant concentration or emission rate. A CEMS can be designed to monitor a single pollutant or multiple pollutants as well as opacity and volumetric flow rate. A sample is collected and then transported from the sampling probe location to the analyzer or monitor.

CEMS is an integration of components which, optimally, operate as one highly reliable system. The system should be capable of initiating calibrations, monitoring system parameters, generating alarms, and communicating the results and data. Components of a CEMS include:

- The Sampling and Conditioning System,
- The Gas Analyzers and/or Monitors depending on system design, and
- Data Acquisition and Handling System (DAHS): the software and the hardware of the CEMS which interfaces with the monitoring system to collect, manipulate, and gather emission data for generating and archiving reports.

The DAHS must be programmed to collect, evaluate, and archive all the data necessary for regulatory reporting and documenting compliance. DAHS mapping and programming be carefully documented to show how all the compliance calculations, conversions, etc. are handled in the system.

NOTE: If a facility uses or wants to use a control device other than those included in Boiler MACT or wants to limit emissions in another manner, the facility must submit a petition to the Administrator requesting approval of the device, operating parameters that will be monitored, and the operating limits that will be established to demonstrate compliance with the emission limits. The petition must be approved by the Administrator prior to initial performance testing.

4.3.1.2 Emissions Averaging

Facilities may use emissions averaging as a tool to comply with emission limits; however, the option is available only for existing affected units within the same subcategory and is limited to PM (or TSM), HCl, and Hg. Facilities using emissions averaging must conduct performance (stack) testing on an annual basis. Also, the averaged emissions cannot be more than 90 percent of the applicable emission limit, according to the procedures in §63.7522. Other considerations include:

- For PM (or TSM) - emissions averaging may be used for units in the same fuel subcategory only (for example, facilities may not average coal and biomass units).

- May include units using CEM/CPMS in emission averaging.
- For HCl and Hg - Emissions averaging may be used for units in any of the solid fuel categories and for units in any of the liquid fuel subcategories.

For a group of two or more existing boilers or process heaters in the same subcategory that each vent to a separate stack, a facility may average PM (or TSM), HCl, or Hg emissions among existing units to demonstrate compliance with the limits in Table 2 to Subpart DDDDD as specified in paragraph (b)(1) through (3) of §63.7522, if the requirements in paragraphs (c) through (g) of §63.7522 are satisfied. Averaging considerations:

(1) A facility may average units using a CEMS or PM CPMS for demonstrating compliance.

(2) For Hg and HCl, averaging is allowed as follows:

- i. A facility may average among units in any of the solid fuel subcategories.
- ii. A facility may average among units in any of the liquid fuel subcategories.
- iii. A facility may average among units in a subcategory of units designed to burn Gas 2 (other) fuels.
- iv. A facility may not average across the units designed to burn liquid, units designed to burn solid fuel, and units designed to burn Gas 2 (other) subcategories.

(3) For PM (or TSM), averaging is only allowed between units within each of the following subcategories and facility may not average across subcategories:

- i. Units Designed to Burn Coal/Solid Fossil Fuel.
- ii. Stokers/Sloped Grate/Other Units Designed to Burn Kiln Dried Biomass/Bio-Based Solids.
- iii. Stokers/Sloped Grate/Other Units Designed to Burn Wet Biomass/Bio-Based Solids.
- iv. Fluidized Bed Units Designed to Burn Biomass/Bio-Based Solid.
- v. Suspension Burners Designed to Burn Biomass/Bio-Based Solid.
- vi. Dutch Ovens/Pile Burners Designed to Burn Biomass/Bio-Based Solid.
- vii. Fuel Cells Designed to Burn Biomass/Bio-Based Solid.
- viii. Hybrid Suspension/Grate Burners Designed to Burn Wet Biomass/Bio-Based Solid.
- ix. Units Designed to Burn Heavy Liquid Fuel.
- x. Units Designed to Burn Light Liquid Fuel.
- xi. Units Designed to Burn Liquid Fuel that are Noncontinental Units.
- xii. Units Designed to Burn Gas 2 (Other) Gases.

Additional guidance on Emissions Averaging is available at §63.7522 of Boiler MACT and in the Appendix of this Guide.

4.3.1.3 Energy (Efficiency) Credits

Boiler MACT provides an opportunity for existing boilers and process heaters (subject to emission limits) to earn efficiency credits from implementation of energy conservation and efficiency measures using output-based emission limits. Efficiency credits can mitigate emission limits. The alternative equivalent output-based emission limits instead of the input-based limits must be used if this election is selected for compliance.

Credit may be taken for implementing energy conservation measures identified in the energy assessment. Credits are generated by the difference between the benchmark and the actual energy demand reductions from energy conservation measures implemented. Benchmarking is the fuel heat input for the one-year period before the date that an energy demand reduction occurs. Emissions credits can be generated if the energy conservation measures were implemented after 1 January 2008. Facilities must:

- Establish a benchmark by determining the actual annual fuel heat input to the affected boiler or process heater before initiation of an energy conservation activity to reduce energy demand.
- Document all uses of energy from the affected boiler or process heater.

Credits cannot be generated from:

- Energy conservation measures implemented on or before 1 January 2008.
- Boilers and process heaters that are permanently shut down unless done strategically to implement energy conservation measures identified in the energy assessment.

The basic efficiency credit process begins with determining the benchmark from which credits are generated using the most representative, accurate, and reliable process available for the source. The benchmark is established for a one-year period before the date that an energy demand reduction occurs, unless it can be demonstrated that a different time period is more representative of historical operations. [§63.7533(b)(1)]

Also, the following needs to be conducted [§63.7533(b)(2 thru 4)]

- Determine the starting point from which to measure progress. Inventory all fuel purchased (and generated, if applicable) on-site in physical units (MMBtu, etc.).
- Document all uses of energy from the affected boiler or process heater using the most recent data available.

- Collect non-energy related facility and operational data to normalize, if necessary, the benchmark to current operations, such as building size, operating hours, etc. If possible, use actual data that are current and timely rather than estimated data.

Additional guidance is included in the Appendix of this Guide, in §63.7533 of Boiler MACT, and from the Department of Energy at: <http://www.epa.gov/ttn/atw/boiler/boilerpg.html>.

4.3.1.4 Waiver for Performance Testing

If stack testing is required for several very similar boilers or process heaters, a petition may be filed with the Administrator to limit testing to a representative unit. All boilers and process heaters subject to stack testing for initial compliance must be tested unless a waiver has been granted by the Administrator pursuant to 40 CFR §§60.8(b)(4), 61.13(h)(1)(iii), or 63.7(h). To summarize 40 CFR 63.7(e)(2)(iv): Emission tests shall be conducted unless the Administrator Waives the requirement for emission testing because the owner or operator of a source has demonstrated by other means to the Administrator's satisfaction that the source is in compliance with the standard. Also, 40 CFR 63.7(h)(2) states: Individual performance tests may be waived upon written application to the Administrator if, in the Administrator's judgment, the source is meeting the relevant standard(s) on a continuous basis, or the source is being operated under an extension of compliance, or the owner or operator has requested an extension of compliance and the Administrator is still considering that request.

A waiver may be appropriate on a case-by-case basis in the following situations:

- A facility has identical boilers or process heaters (same manufacturer, model number or other manufacturer's identifier, rated capacity, and specifications) and each unit is operated and maintained in a similar manner. The assumption is the performance test results for one tested unit are representative of all identical units located at the facility as long as the units are performing under the same conditions on an ongoing basis; therefore, the facility may request that the administrator waive the requirement to the other units in the group if the tested unit demonstrates compliance with the standards. The expected emissions from the boilers or process heaters should be in compliance with applicable limits by a substantial margin. If the margin is not substantial, other factors may be considered, if there is sufficient emissions data to determine that the variability of emissions for identical tested units is low enough for confidence that the untested unit(s) will also be in compliance.
- Technical or economic infeasibility, or when the impracticality of the affected source's performing the required test is demonstrated.
- If the facility is operating under an extension of compliance pursuant to §63.6(i), or has requested such an extension and the request is under consideration by the delegated agency.

The Administrator may request for the request for a waiver and extension be submitted simultaneously.

- Force majeure; an event caused by circumstances beyond the control of the owner/operator, the testing company, or any contractor controlled by the affected source that prevents the owner/operator from complying with the regulatory requirement to conduct or complete performance tests within the specified time frame despite the affected source's best efforts to fulfill the obligation.
- If the facility has demonstrated by other means that the emissions unit is in compliance with the applicable standard and other requirements.

NOTE: If units do NOT have the ability to emit a pollutant(s) in excess of prescribed emission limit(s), waivers on a case-by-case basis, may be issued for BOTH initial and ongoing compliance stack tests.

The burden of proof is on the facility to justify the need for a waiver. If a performance test waiver is granted for only one or some emissions units at a source, but other emissions units still require testing, a copy of the waiver and a list of the emissions units whose test requirements have been waived must be included in the protocol and final performance test report.

Waivers can be granted by a delegated agency. The request for a waiver should include the following, at a minimum:

- Information justifying the request for a waiver, such as the technical or economic infeasibility, or the impracticality, of the affected source performing the required test or information demonstrating how the boiler or process heaters are identical or similar (model number, location, processes, maintenance schedule and procedures, etc.).
- Complete test results, sampling methodology, calculations, quality assurance methods, air pollution control devices and monitoring data used during test (test data should be obtained using approved EPA methods), if available or applicable.

4.3.2 Task 2: Develop Applicable Compliance Plans

Compliance with emission limits does not begin with the initial performance test, but with the careful drafting of the appropriate compliance plans. The facility needs to ensure that plans are drafted in a manner that meets compliance requirements while making sure the facility can comply with the obligations established within the plans. Although every scenario can't be covered, the following information can assist in determining which compliance plans are required and the basic contents of each. The following table provides a summary of the compliance plans a facility may require:

Table 4-2. Compliance Plans.

Boiler MACT Compliance Plans	
Plan Type	When Plan is Required
Performance Test/Quality Assurance Plan §63.7(c)	Required if using stack testing to comply
Site-Specific Fuel Monitoring Plan §63.8(d)	Required if fuel analysis or other fuel-related compliance method is used
Site-Specific Monitoring Plan	Required if monitoring is necessary
Start-up and Shut-down Plan	Required if using Definition 2 of Startup
Emissions Averaging Plan	Required if using Emission Averaging
Energy Efficiency Implementation Plan	Required if using Energy Credits

Required Compliance Plans - The following implementation plans are required and must be in place **at least 60 days prior** to conducting the initial compliance demonstration. A copy of the plan must be kept on-site as a record. Generally, plans are not required to be submitted unless requested by an Administrator or unless the facility intends to use an analytical method or approach that differs from those required by Subpart DDDDD. Any variance from Subpart DDDDD requires the plan to be submitted to the appropriate Administrator for review and approval. Until authorized to use an intermediate or major change or alternative to a method, the affected source remains subject to the relevant standard.

Startup and Shutdown Plan (SSP) §63.7505(e) – During these events, periods of elevated emissions can result which may exceed applicable emission limits. If the boiler or process heater is subject to emission limits, and uses Definition 2 of “start-up” in §63.7575 to comply with work practices, a SSP must be developed and implemented. The new version of Boiler MACT (published on 20 November 2015) requires an SSP, but does not include specifics on what is included within the plan.

Performance (Stack) Test/Quality Assurance (QA) Plan §63.7520(a) – A site-specific stack test plan must be developed according to the requirements in 40 CFR §63.7(c). The plan includes, but is not limited to the following information:

- Test program summary.
- Test schedule.
- Stack sampling location, control devices, testing conditions, etc.
- Data quality objectives (the pretest expectations of precision, accuracy, and completeness of data).
- Internal and external quality assurance program.

Fuel Analysis/Monitoring Plan §63.7521(g) – A site-specific fuel analysis/monitoring plan must be developed and implemented before conducting a required Performance Test and/or if a fuel analysis in lieu of Performance Testing is used to demonstrate compliance. The purpose of this plan is to identify the pollutant input loading to the boiler or process heater during the Performance Test, which will then become an operating limit (or an Emission Limit if using fuel analysis as the compliance option) until the next Performance Test is conducted. *A site-specific fuel analysis plan does not need to be submitted for review and approval if conducting a fuel analysis for “other Gas 1 fuels” unless an alternative analytical method other than those required by Table 6 is intended to be used.* The plan includes, but is not limited to, the following information for each anticipated fuel type:

- The identification of all fuel types anticipated to be burned in each boiler or process heater other than those exempted from fuel specification analysis under (f)(1) through (4) of §63.7521 anticipated to be burned in each boiler or process heater [§63.7521(g)(2)(i)].
- Identification of whether the facility or a fuel supplier will be conducting the fuel analysis [§63.7521(g)(2)(ii)].
 - If the fuel supplier will be conducting the fuel analysis in lieu of site-specific sampling and analysis, the fuel supplier must use the analytical methods required by Table 6 of 40 CFR Part 63, Subpart DDDDD. When using a fuel supplier’s fuel analysis, the owner or operator is not required to include the sample location and procedures used for collecting and preparing the samples in the site-specific fuel analysis plan [§63.7521(g)(2)(vi)]
- A detailed description of the sample location and specific procedures to be used for collecting and preparing the composite samples if the procedures are different from paragraph (c) or (d) of 40 CFR 63.7521. Samples should be collected at a location that most accurately represents the fuel type, where possible, at a point prior to mixing with other dissimilar fuel types [§63.7521(g)(2)(iii)].
- The analytical methods from Table 6, Subpart DDDDD, with the expected minimum detection levels, to be used for the measurement of chlorine or mercury [§63.7521(g)(2)(iv)].
- The analytical methods that differ from those required by Table 6 of Subpart DDDDD, if any.
 - A detailed description of the methods and procedures that the facility is proposing to use. Methods in Table 6 of Subpart DDDDD must be used until the requested alternative is approved. [§63.7521(g)(2)(v)]

Monitoring Plan §63.7505(d) - If compliance is demonstrated through monitoring, a site-specific monitoring plan is required. CEMS, COMS, and CPMS are collectively referred to as CMSs. A site-specific monitoring plan is also required if petitioning the EPA for alternative monitoring

parameters (including alternative monitoring system quality assurance and quality control procedures) per 40 CFR §63.8(f). A site-specific monitoring plan is not required if the facility has an existing plan prepared under Appendix B to Part 60 that apply to CEMS and COMS (which meets the monitoring, installation, operation, and maintenance requirements of Boiler MACT). The plan includes, but is not limited to, the following information:

- Performance and equipment specifications.
- Performance evaluation procedures and acceptance criteria (pass/fail tolerances).
- Procedures with data reduction requirements.
- Determination and adjustment of the calibration drift of the CMS.
- Initial and subsequent calibration of the CMS.
- Preventive maintenance of the CMS (operations and maintenance).
- Corrective action procedures for a malfunctioning CMS.
- Basis for selection of the CMS measurement location relative to each affected source such that the measurement is representative of control of the exhaust emissions (installation of the CMS sampling probe or other interface at a predetermined area).
- Procedures for data quality assurance and ongoing recordkeeping/reporting [quality assurance and quality control elements outlined in §63.8(d)].

Internal and External Quality Assurance Program

The Monitoring Plan and Performance Testing Plan require an internal and external Quality Assurance Program. Quality Assurance (QA) and Quality Control (QC) are independent, but interrelated functions. QC are activities performed to provide a consistent and reproducible result (e.g., routine maintenance, system inspections, periodic calibrations). Whereas, QA are activities implemented to ensure QC is performing adequately. A complete QA Plan involves both QA and QC functions. In order to maintain ongoing QA, the site-specific performance and monitoring plans require the development of an internal and external QA program. A QA Plan is the basis for assessing and maintaining of the quality of continuous emission monitoring data.

The ultimate goal of the QA program is to provide acceptable emission data in sufficient quantity to demonstrate compliance. The internal QA program shall include, at a minimum, the activities planned by routine operators and analysts to provide an assessment of test data precision (e.g., sampling and analysis of replicate samples). The external QA program shall include, at a minimum, the following:

- Provisions for a test method performance audit during the Performance Test, in order to provide a measure of test data bias;

- Provisions for systems audits, instrument calibration, data validation, sample logging, and documentation of quality control data and field maintenance activities; and
- Provisions to provide appropriate notice (60 days), to the Administrator, of the Performance Test, performance audit, and systems audit, allowing the regulating agency the opportunity to arrange for their own on-site evaluation.

QA requires the implementation of external checks on data quality (e.g., independent system audits, third party sample and analysis). The Administrator may request additional relevant information following the receipt and review of the site-specific plan.

Optional Plans – The development of an implementation plan is required if the applicable compliance option is selected. The implementation plan must be in place at least 180 days prior to the date the facility intends to demonstrate compliance using the option. Generally, plans do not have to be submitted unless requested by an Administrator or unless the facility intends to use an analytical method or approach that differs from those required by Subpart DDDDD. Any variance from Subpart DDDDD requires approval from the appropriate Administrator. A copy of the plan must be kept on site as a record.

Emissions Averaging Implementation Plan §63.7522(g) - Boiler MACT allows emissions averaging as a compliance option. Some facilities may find that emissions averaging is a valuable approach to compliance. The requirement to develop and submit an emissions averaging plan is a component of this option. The plan includes, but is not limited to, the following information:

- Identification of all existing boilers or process heaters in averaging group.
- Date on which emission averaging is to commence.
- Identification of the monitored process parameter for each averaging group.
- Specific control technology or pollution prevention methods used for each boiler or process heater.
- Test plan for measurement of emissions.

Energy Efficiency Implementation Plan §63.7533(d) - Energy efficiency credits are another option for existing boilers per §63.7533 of Boiler MACT. A facility may meet certain criteria to take credit for implementing energy conservation measures identified in the energy assessment. This compliance approach cannot be used for a new or reconstructed affected boiler. If electing to use efficiency credits from energy conservation measures to demonstrate compliance, a copy of the implementation plan and copies of all data and calculations used to establish credits must be kept on site. The plan includes, but is not limited to the following information:

- Identification of boilers to include in applying efficiency credits
- Description and explanation of energy conservation measures implemented and associated savings

4.3.3 Task 3: Comply with Initial Test/Evaluation Notification Requirements

Notification of Intent to Conduct a Performance Test or Performance Evaluation must be submitted at least 60 days before the test/evaluation is scheduled to begin. The Administrator will likely request that the applicable site-specific plan(s) be submitted with the notifications. This allows the Administrator to review and approve the plan(s) and to have an observer present during the test and/or evaluation. The notification shall describe in detail [40 CFR §63.7(b) and §63.9(e)]:

- The proposed test and/or evaluation methods and procedures
- The monitored operating parameters
- Data quality objectives
- An internal and external QA program
- The time(s) and date(s) of the test(s)
- The person(s) whom will be conducting the test(s)

In the event the Performance Test or Evaluation cannot be conducted on the date specified in the notification requirement due to unforeseeable circumstances beyond the requester's control, the Administrator must be notified as soon as practicable prior to the scheduled date (provide the rescheduled date).

4.3.4 Task 4: Determine Emission Limits

The Boiler MACT emission limits for PM (or TSM), HCl, CO, and Hg depend on the amount of fuel consumed by the boiler or process heater in units of pounds per million Btu (lb/MMBtu). The emission limits are organized by pollutant which can vary depending on the boiler or process heater's subcategory. To reflect differing operating conditions, emission limits are further broken down by unit design/firing configuration for units designed to burn solid fuel and by type/location for units designed to burn liquid fuel. For example, boilers and process heaters in the solid fuel (coal and biomass) subcategory share a common HCl and Hg Emission Limit. However, there is a different PM Emission Limit for the coal/solid fuel subcategory and the CO limits for coal/solid fossil fueled units vary depending on the design type of the unit. Table 4-3, *Organization of Emission Limits*, demonstrates how the emission limits are organized in Table 1 and Table 2 of Subpart DDDDD:

NOTE: The emission limits are subject to change, particularly the CO limit. With the 30 November 2015, Final Boiler MACT rule, the EPA retained the minimum CO limit of 130 parts per million (ppm). However, on 16 March 2018, the D.C. Circuit Court of Appeals held that EPA did not justify its conclusion that HAP could not be reduced any further after CO emissions reached 130 ppm. The court did not vacate the 130 ppm limit but told the EPA to reconsider the CO limit.

Table 4-3. Organization of Emission Limits.

Boiler MACT Organization of Emission Limits per Subcategory				
Pollutant Emission Limit	Units Designed to Burn Solid Fuel		Units Designed to Burn Gas 2 (Other) Gases	Units Designed to Burn Liquid Fuel
	Units Designed to Burn Coal and Solid Fossil Fuel	Units Designed to Burn Biomass and Bio-Based Solids		
	Emission Limits Based on...			
HCl Emission Limit	Solid Fuel Subcategory	Solid Fuel Subcategory	Gas 2 Subcategory	Liquid Fuel Subcategory
Hg Emission Limit	Solid Fuel Subcategory	Solid Fuel Subcategory	Gas 2 Subcategory	Liquid Fuel Subcategory
PM (or TSM) Emission Limit	Coal/Solid Fossil Fuel Subcategory	Design/Combustion Subcategory	Gas 2 Subcategory	Heavy, Light, or Noncontinental Subcategory
CO (or CO CEMS) Emission Limit	Design/Combustion Subcategory	Design/Combustion Subcategory	Gas 2 Subcategory	Heavy, Light, or Noncontinental Subcategory

How to find the correct Emission Limit for the boiler or process heater:

Numerical emission limits are located in Table 1 and Table 2 to Subpart DDDDD (Emission Limit Tables are also provided in the Appendix of this Guide for reference).

- Table 1 of Subpart DDDDD contains the emission limits for new and reconstructed boilers and process heaters.
- Table 2 of Subpart DDDDD contains the emission limits for existing boilers and process heaters.
- Tables 1 and 2 of Subpart DDDDD also contain sampling times and volumes based on the fuel type and firing configuration of the boiler or process heater.

The appropriate limit must be converted to an allowable emission rate (lb/hr) based on the unit's firing rate (MMBtu/hr). Once emission concentrations are determined, they are converted to lb/MMBtu emission rates using Method 19 F factor methodology contained within 40 CFR 60. The rate can be calculated based on heat input, steam output, or electricity output.

Alternate Emission Limits -

Alternate emission limits are also provided within Table 1 and Table 2 of Subpart DDDDD. There is an alternative emission limit available within most subcategories for TSM, if electing to use TSM as a surrogate for filterable PM. Also, if the boiler or process heater uses a certified CO CEMS, an alternative Emission Limit is provided in the Tables for most subcategories. If an alternative Emission Limit is not listed in the emission limit tables for a subcategory, then that compliance option is not available for boilers and process heaters in that subcategory. For example, because there is no alternative CO CEMS-based emission limit for units in the liquid fuel subcategory, those units must comply with a stack test and then demonstrate continuous compliance by maintaining the oxygen operating limit.

Heat Input or Output Based Emission Limits

One noteworthy feature of Boiler MACT is the option of using output-based emission limits. The traditional emission limit format is based on heat-input; however, Boiler MACT offers alternative output-based emission limits to provide compliance flexibility and encourage energy efficiency by relating emissions to energy output. Compliance with the output-based limits requires measurement of boiler operating parameters associated with the mass rate of emissions and energy outputs (equations provided in the rule). A facility may demonstrate compliance with either the input-based (lb/MMBtu) limit or the output-based (lb/MMBtu steam or lb/megawatt-hour (MWh)) limit with some considerations:

- The output-based emission limits must be selected if electing to take credit for implementing energy conservation measures that were identified during the energy assessment.
- Electric output data is typically measured in lb/MWh and thermal output is typically measured in pounds per million Btu (lb/MMBtu).
 - The output-based emission limits, in lb/MMBtu of steam output, are applicable to boilers and process heaters that generate either steam, cogenerate steam with electricity, or both.
 - The output-based emission limits, in lb/MWh, are an alternative applicable only to boilers and process heaters that generate electricity.
 - Boilers and process heaters that perform multiple functions (cogeneration and electricity generation) or supply steam to common headers will calculate a total steam energy output using Equation 21 of §63.7575 to demonstrate compliance with the output-based emission limits, in lb/MMBtu of steam output.

In the case of boilers supplying steam to one or more common heaters, S1, S2, and MW(3) for each boiler would be calculated based on the its (steam energy) contribution (fraction of total steam energy) to the common heater.

$$SO_m = S_1 + S_2 + (MW_{(3)} \times CF_n) \quad \text{Equation 21}$$

Where:

SO_m = Total steam output for multi-function boiler, MMBtu

S_1 = Energy content of steam sent directly to the process and/or used for heating, MMBtu

S_2 = Energy content of turbine steam sent to the process plus energy in electricity according to (2) above, MMBtu

$MW_{(3)}$ = Electricity generated according to paragraph (3) of this definition, MWh

CF_n = Conversion factor for the appropriate subcategory for converting electricity generated according to paragraph (3) of this definition to equivalent steam energy, MMBtu/MWh

CF_n for emission limits for boilers in the unit designed to burn solid fuel subcategory = 10.8

CF_n PM and CO emission limits for boilers in one of the subcategories of units designed to burn coal

NOTE: Convert emissions concentration to lb/MMBtu emission rates using Method 19 F-factor methodology at 40 CFR Part 60, Appendix A-7.

4.3.5 Task 5: Conduct Initial Performance (Stack) Testing

Initial Performance Testing must be completed by the following dates:

- Existing units: 29 July 2016 or no later than 180 days after re-start of a boiler that was not operated following the compliance date or that has not operated for over a year following the last compliance demonstration. [40 CFR 63.7510(e) and (j)], [40 CFR 63.7515(g)], [40 CFR 63.7495(b)], and [40 CFR 63.7(a)(2)]
- New/Reconstructed units: The performance test should have been performed on 30 July 2013 or 180 days after start-up, whichever is later. [§63.7510(f)]

The general requirements for Performance (stack) Testing are provided in this section. More specific procedures are located in §63.7520, Table 5 of Subpart DDDDD, and §63.7(c), (d), (f), and (h). Further guidance with Performance Testing is provided in the Appendix to this Guide.

NOTE: Previous test data can satisfy the initial compliance requirement in Boiler MACT (emission standards and operating limits), as long as the test met all the requirements and operating conditions set forth in the rule. The test results must be submitted with the Notification of Compliance Status.

Performance (stack) Testing (also known as “compliance testing” or “emissions testing”) serves a dual purpose:

- To determine compliance with emission limits.

- To set operating parameters for the boiler or process heater as well as the associated air pollution control equipment.

Stack testing is an important tool used to determine a facility's compliance with emission limits. A Stack Test not only measures the amount of a specific regulated pollutant or surrogates being emitted from the boiler or process heater, the test also demonstrates the capture or destruction efficiency of an air pollution control device. Stack tests are performed to determine the types and amounts of air pollutants emitted from the boiler or process heater. The specific methodologies used for compliance demonstrations are provided in Table 5 of Subpart DDDDD and detailed in 40 CFR 60, Appendix A.

For boilers, the stack testing procedure itself employs a “test and cap” technique. Facilities are required to perform an initial stack test while combusting fuel containing the highest expected concentration of chlorine and mercury (and TSM if opting to comply with the TSM alternative standard). A representative sample is extracted from the boiler at an optimally located sampling port (refer to Table 5 of Subpart DDDDD for the appropriate locations of the sampling port). The sample is then analyzed using either a field analytical instrument or sending the sample to an EPA approved laboratory for analysis. Also, during the stack test, the facility collects operating data from the control device(s) to identify the device(s) normal operating range and to establish operating parameters. Certain key indicators of system performance, such as flow rate or pressure drop, depending on the device being used, demonstrate that the device is operating properly for adequate control of emissions/pollutant. These indicators (frequently referred to as parameters) must be measured and monitored per the requirements in Subpart DDDDD. Afterwards, continuous compliance is demonstrated by maintaining the fuel pollutant concentration(s) below the level that was measured and maintaining control device operating parameters within the limits observed during the initial test.

Generally, performance (stack) tests are conducted under representative, or normal, operating conditions for the boiler or process heater. The conditions are typically specified by the Administrator. The facility provides records, upon request, to assist the Administrator in determining the conditions of performance tests. Operations during periods of start-up, shut-down, and malfunction shall not constitute representative conditions for the purpose of a performance test, nor shall emissions in excess of the level of the relevant standard during such periods be considered a violation unless otherwise specified in the rule or unless a determination of noncompliance is made under §63.6(e). [§63.7(e)(1)]

General Requirements for Performance Testing, per §63.7, include:

- Providing testing facilities that are adequate and safe to conduct stack testing.

- Providing a stack or duct free of cyclonic flow during performance tests, as demonstrated by applicable test methods and procedures.
- Completing a test method performance audit during the Performance Test (the performance audits consist of blind audit samples, supplied by an accredited audit sample provider and analyzed during the Performance Test, in order to provide a measure of test data bias).
- If an affected boiler and a non-affected unit(s) vent(s) to a common stack, the non-affected unit(s) must be shut down or vented to a different stack during the Performance Test, unless compliance can be demonstrated with the non-affected units venting to the stack during the performance demonstration.
- Boiler MACT requires that Performance Tests be conducted at representative operating load conditions while combusting the type of fuel or mixture of fuels that has the highest content of chlorine and mercury (and TSM for sources opting to comply with TSM alternative).
- All CMSs must be installed, operational, and the data verified prior to or in conjunction with conducting Performance Tests. [40 CFR §63.7 and §63.7505(d)]
- For boilers complying with the CO emission limit using performance testing, an oxygen analyzer or continuous oxygen trim system must be operated at or above the oxygen level established during the performance test.
- Three separate test runs for each Performance Test is required as specified in §63.7(e)(3). Each test run must comply with the minimum applicable sampling times or volumes specified based on fuel type and firing configuration (Table 1 and Table 2 to Subpart DDDDD).
- The F-Factor methodology and equations in sections 12.2 and 12.3 of EPA Method 19 at 40 CFR Part 60, Appendix A-7 must be used to convert the measured PM concentrations, the measured HCl concentrations, the measured Hg concentrations, and the measured TSM concentrations that result from the Performance Test to lb/MMBtu heat input emission rates.
- Operating limits are established based on Performance Testing. Following each Performance Test and until the next Performance Test, the operating limits and operating load conditions specified in Table 4 to Subpart DDDDD must be complied with. Operating limits must be confirmed or reestablished during subsequent Performance Tests

NOTE: As an alternative to performance stack testing for Hg, HCl, or TSM, a fuel analysis may be conducted to demonstrate that the fuel pollutant input is lower than the applicable emission if the emission rate calculated according to §63.7530(c) is less than the applicable Emission Limit. If compliance is based on fuel analysis, monthly fuel analysis for each type of fuel combusted is required. A site-specific fuel monitoring plan must be developed and followed. Otherwise,

Performance Testing must be used to demonstrate compliance with Hg, HCl, or TSM emission limits.

4.3.6 Task 6: Conduct Fuel Analysis

Fuel analysis (sampling and testing) is an important component in meeting emission limits. The general requirements of fuel analysis are provided in this section. The specific procedures are provided in the Appendix to this Guide.

NOTE: In lieu of site-specific fuel sampling and analysis, the required fuel information can be obtained from the fuel supplier. **If using fuel analysis from a fuel supplier instead of site-specific sampling and analysis, the fuel supplier must use the analytical methods required by Table 6 of Subpart DDDDD.**

Emissions of certain pollutants depend on the grade of fuel fired in the boiler or process heater. Emissions for the fuel can be estimated through fuel analysis. As discussed in the previous section, boilers and process heaters demonstrating compliance with the Hg, HCl, or TSM emission limit through stack testing must conduct an initial fuel analysis for each type of fuel burned in the unit according to §63.7521 and Table 6 to Subpart DDDDD. This is to determine the highest emissions potential for HCl, Hg, and/or TSM. Multiple-fueled boilers and process heaters are required to conduct a fuel analysis while single fueled boilers are exempt from fuel analysis. However, fuel analysis can be used for most single fueled boilers and process heaters electing to demonstrate compliance with HCl, Hg, and/or TSM emissions limits using fuel analyses rather than through performance testing.

4.3.6.1 Exemptions from Fuel Analysis

To avoid conducting a fuel analysis, when one is not warranted, consider the fuel analysis exemptions in §63.7510(a)(2) carefully. For example, a boiler which primarily burns Gas 1, but burns oil for more than 48 hours during a calendar year for transient flame stability would fall in the "Unit Designed to Burn Liquid Fuel" subcategory. However, the boiler is not likely subject to a fuel analysis during initial compliance because the unit would probably fall under "unit burning a single type of fuel" under §63.7510(a)(2)(i) or "unit burning natural gas co-fired with other fuels" under §63.7510(a)(2)(ii). The exemptions are listed below [§63.7510(a)(2)(ii-iii)]:

- For each boiler or process heater that burns a single type of fuel, a fuel analysis is not required for each type of fuel burned in the boiler or process heater.
- Boilers and process heaters that use a supplemental fuel only for start-up, unit shut-down, and transient flame stability purposes still qualify as units that burn a single type of fuel, and the supplemental fuel is not subject to the fuel analysis requirements.

- When natural gas, refinery gas, or other Gas 1 fuels are co-fired with other fuels, a fuel analysis is not required to be conducted of those Gas 1 fuels.
- If gaseous fuels other than natural gas, refinery gas, or other Gas 1 fuels are co-fired with other fuels and those non-Gas 1 gaseous fuels are subject to another subpart of Part 63, Part 60, Part 61, or Part 65, a fuel analysis is not required of those non-Gas 1 fuels.
- A chlorine fuel analysis is not required for any gaseous fuels. However, a fuel analysis for Hg on gaseous fuels is required unless the fuel is otherwise exempted.

4.3.6.2 Compliance using Fuel Analysis as an Alternative to Stack Testing

As stated previously, a benefit of a single fuel boiler or process heater is that fuel analyses is not required when conducting an initial performance test; however, testing can be used for a single fueled source that elects to demonstrate compliance with HCl, Hg, and/or TSM emissions limits using fuel analyses rather than through performance testing. For some facilities, compliance through fuel analysis may be a less burdensome and less expensive compliance option than stack testing for each pollutant. Using this compliance option, a fuel analysis is required for each type of fuel burned and calculations performed to demonstrate that the pollutant concentration in the fuel is less than the emissions limit. If the potential emission rate of the fuel or fuel mixture exceeds the applicable Boiler MACT emission limit, then compliance through fuel analysis is not an option. If compliance is based on fuel analysis, monthly fuel analysis for each type of fuel will be required. To use this alternative:

- Demonstrate that the calculated emission rate according to §63.7521(e) and Equation 15 of Subpart DDDDD is less than the Hg, HCl, or TSM emission limit.
- Conduct a fuel analysis each month for each type of fuel burned, reduce the data to a 12 month rolling average, and maintain the 12-month rolling average at or below the emission limit.
- If planning to burn a new type of fuel or fuel mixture, a fuel analysis must be conducted before burning the new fuel or mixture in the boiler or process heater. Recalculate the Hg, HCl, or TSM emission rate according to §63.7521 and Equation 15 of Subpart DDDDD.
 - The resulting Hg, HCl, or TSM emission rate for the new type of fuel or fuel mixture must be less than the applicable emission limit.
 - If the pollutant concentration for the new fuel type or mixture is higher than for the fuel used during the previous performance test, then a new performance test must be conducted within 60 days of burning the new fuel type or mixture.

Must use Equation 15 to Demonstrate Compliance –

The 90th percentile confidence level (P90) must not exceed the applicable emission limit, based on worst case fuel type or mixture.

Equation 15 - The 90th percentile confidence level must be determined for the fuel pollutant concentration of the composite samples analyzed for each fuel type using the one-sided t-statistic test described in Equation 15 of §63.7530. [§63.7530(c)(2)]

$$P90 = \text{mean} + (SD \times t) \quad (\text{Equation 15})$$

Where:

P90 = 90th percentile confidence level pollutant concentration, in lb/MMBtu.

Mean = Arithmetic average of the fuel pollutant concentration in the fuel samples analyzed according to §63.7521 in units of lb/MMBtu.

SD = Standard deviation of the mean of pollutant concentration in the fuel samples analyzed according to §63.7521 in units of lb/MMBtu. SD is calculated as the sample standard deviation divided by the square root of the number of samples.

t = t distribution critical value for 90th percentile ($t_{0.1}$) probability for the appropriate degrees of freedom (number of samples minus one) as obtained from a t-Distribution Critical Value Table.

4.3.6.3 Equivalent or Alternative Fuel Analysis Testing Methods

The requirements for fuel analysis testing for existing, new or reconstructed affected sources is included within Table 6 of Subpart DDDDD. If necessary, an alternative method may be used if included in the Fuel Analysis Plan which is submitted to the EPA for review and approval [§63.7521(b)(1)]. However, an “equivalent method” can be used for fuel analysis without prior approval. “Equivalent”, as it applies to Table 6 of Subpart DDDDD only, is defined in 63.7575 as:

- An equivalent sample collection procedure means a published Voluntary Consensus Standard or practice (VCS) or EPA method that includes collection of a minimum of three composite fuel samples, with each composite consisting of a minimum of three increments collected at approximately equal intervals over the test period.
- An equivalent sample compositing procedure means a published VCS or EPA method to systematically mix and obtain a representative subsample (part) of the composite sample.
- An equivalent sample preparation procedure means a published VCS or EPA method that: Clearly states that the standard, practice or method is appropriate for the pollutant and the fuel matrix; or is cited as an appropriate sample preparation standard, practice or method for the pollutant in the chosen VCS or EPA determinative or analytical method.

- An equivalent procedure for determining heat content means a published VCS or EPA method to obtain gross calorific (or higher heating) value.
- An equivalent procedure for determining fuel moisture content means a published VCS or EPA method to obtain moisture content. If the sample analysis plan calls for determining metals (especially the mercury, selenium, or arsenic) using an aliquot of the dried sample, then the drying temperature must be modified to prevent vaporizing these metals. On the other hand, if metals analysis is done on an “as received” basis, a separate aliquot can be dried to determine moisture content and the metals concentration mathematically adjusted to a dry basis.
- An equivalent pollutant (Hg, HCl) determinative or analytical procedure means a published VCS or EPA method that clearly states that the standard, practice, or method is appropriate for the pollutant and the fuel matrix and has a published detection limit equal or lower than the methods listed in Table 6 to this subpart for the same purpose.

4.3.7 Task 7: Establish Operating Limits during the Performance Test

NOTE: Operation above the established maximum or below the established minimum operating limits shall constitute a deviation of established operating limits except during Performance Tests conducted to determine compliance with the emission limits or to establish new operating limits. A deviation is not always a violation.

This section contains general information regarding operating limits. More details are provided in Subpart DDDDD (Table 7 of Subpart DDDDD specifies how to establish operating parameters) and in the Appendix of this Guide (refer to Performance Testing).

Operating limits are parameters and/or conditions placed on a boiler, process heater, or associated equipment to ensure that the emission limits are being met. Operating limits can include:

- Operating limits for control devices.
- Maximum fuel pollutant concentrations.
- Operating loads.

Operating limits are established for air pollution control devices during the performance test and are dependent on the pollutant and type of air pollution control device used. For example, a boiler with a baghouse (system of fabric filters) is likely to exceed the emission limit for PM if a fabric filter (bag) is defective or leaks; therefore, the boiler must be operated so that the bag leak detection system alarm does not sound more than 5 percent of the operating time during a 6-month period. Alternatively, if the fabric filter does not have a bag leak detection system, opacity can be used as a limit since that is also an indicator of fabric filter performance.

For operating limits that require the use of parametric monitoring, facilities will be required to install, operate, and maintain a CPMS. The following parameters, with compliance ranges established during performance tests, must be monitored using CPMS:

- Wet Scrubber - Pressure drop, liquid flow rate, pH (for HCl control).
- Dry Scrubber - Sorbent injection rate (HCl) and/or Activated Carbon injection rate (Hg).
- ESP (with wet control systems, aka Wet ESP) - Voltage and secondary current or total power input.
- ESP (with dry control systems, aka Dry ESP) – Opacity.
- Fabric Filter (aka Baghouse) with a Bag Leak Detection System - Alert/Alarm Times.
- Fabric Filter (aka Baghouse) without a Bag Leak Detection System – Opacity.
- Other dry controls – Opacity.

New control technologies, particularly for PM and Hg, continue to emerge. Approval of alternative control equipment and/or methods must be obtained from the Administrator if requesting permission to use a control device or method not included within Boiler MACT.

4.3.7.1 Procedure for Establishing Operating Limits

NOTE: There is no requirement to establish and comply with the operating parameter limits when the facility is using a CEMS to monitor and demonstrate compliance with the applicable emission limit for that control device parameter [§63.7530(b)(4)].

The fundamental procedure for establishing Operating Limits (also sometimes referred to as operating parameters) includes:

- Collect parameter data during performance testing.
- Calculate the hourly averages.
- Determine the minimum or maximum parameter value (the lowest or highest hourly average value measured during the most recent performance test demonstrating compliance with the applicable emission limit).

The operating limits for compliance methods (such as control devices and technology) are identified in Table 4 of Subpart DDDDD. The procedure for establishing those operating limits as specified in Table 7 of Subpart DDDDD. The control devices and methods are discussed below.

Establishing Operating Limits if a Wet PM Scrubber is used for Compliance (if not using PM CPMS) – Any add-on air pollution control device that mixes an aqueous stream or slurry with the exhaust gases from a boiler or process heater to control emissions of PM. A wet scrubber creates an aqueous stream or slurry as a byproduct of the emissions control process.

- Establish a site-specific minimum scrubber pressure drop and minimum flow rate operating limit according to §63.7530(b) using data from the scrubber pressure drop and liquid flow rate monitors and the PM, TSM, or Hg performance test. Collect scrubber pressure drop and liquid flow rate data every 15 minutes during the entire period of the performance tests. Determine the lowest hourly average scrubber pressure drop and liquid flow rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.
- Maintain 30-day rolling average pressure drop and 30-day rolling average liquid flow rate at or above lowest 1-hour averages established during most recent Performance Test.

Establishing Operating Limits if a Fabric Filter is used for Compliance (if PM CPMS is not required) – A fabric filter is an add-on air pollution control device used to capture PM by filtering gas streams through filter media, also known as a baghouse. A fabric filter must:

- Maintain opacity to less than or equal to 10 % daily block average or the highest hourly average opacity reading measured during the most recent performance test.

OR

- Operate the bag leak detection system such that alarm does not sound more than 5% of operating time during each 6-month period.

A Bag leak detection system is a group of instruments capable of monitoring PM loadings in the exhaust of a fabric filter (i.e., baghouse) in order to detect bag failures. A bag leak detection system includes, but is not limited to, an instrument that operates on electrodynamic, triboelectric, light scattering, light transmittance, or other principle to monitor relative particulate matter loadings. If a fabric filter bag leak detection system is used to comply with the requirements of Subpart DDDDD, install, calibrate, maintain, and continuously operate the bag leak detection system as specified in paragraphs (j)(1) through (6) of §63.7525:

1. The bag leak detection sensor(s) must be installed in a position(s) that will be representative of the relative or absolute PM loadings for each exhaust stack, roof vent, or compartment (e.g., for a positive pressure fabric filter) of the fabric filter.
2. Conduct a performance evaluation of the bag leak detection system in accordance with the monitoring plan and consistent with the guidance provided in EPA-454/R-98-015 (incorporated by reference, see §63.14).
3. Use a bag leak detection system certified by the manufacturer to be capable of detecting PM emissions at concentrations of 10 milligrams per actual cubic meter or less.
4. Use a bag leak detection system equipped with a device to record continuously the output signal from the sensor.

5. Use a bag leak detection system equipped with a system that will alert plant operating personnel when an increase in relative PM emissions over a preset level is detected. The alert must easily recognizable (e.g., heard or seen) by plant operating personnel.
6. Where multiple bag leak detectors are required, the system's instrumentation and alert may be shared among detectors.

Establishing Operating Limits if ESP is being used for Compliance (if not required or electing to use PM CPMS) – An ESP is add-on air pollution control device used to capture PM by charging the particles using an electrostatic field, collecting the particles using a grounded collecting surface, and transporting the particles into a hopper. An electrostatic precipitator is usually a dry control system. When an ESP control device is used, the following must be considered:

- Establish a site-specific minimum total secondary electric power input according to §63.7530(b) using data from the voltage and secondary amperage monitors during the PM or Hg performance test. Collect secondary voltage and secondary amperage for each ESP cell and calculate total secondary electric power input data every 15 minutes during the entire period of the performance tests. Determine the average total secondary electric power input by computing the hourly averages using all of the 15 minute readings taken during each performance test. *This is an option only for units that operate wet scrubbers.*
- Existing and new boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (daily block average); or the highest hourly average opacity reading measured during the most recent performance test. *This option is for boilers and process heaters that operate dry control systems (i.e., an ESP without a wet scrubber).*
- Maintain the 30-day rolling average total secondary electric power input of the ESP at or above the operating limits established during the performance test according to §63.7530(b) and Table 7 to Subpart DDDDD. *This option is only for boilers and process heaters not subject to PM CPMS or continuous compliance with an opacity limit (i.e., dry ESP).*

NOTE: Boilers and process heaters that use a dry ESP to comply with the PM limit and that do not use a PM CPMS are required to continuously monitor opacity. Additionally, these systems are required to maintain opacity below 10% on a daily block average basis or the highest hourly average opacity reading measured during the most recent performance test.

Establishing Operating Limits if Opacity is used for Compliance – Opacity is a measure of the amount of light fraction of transmitted light obscured by particles. Opacity often is used as an indicator of the degree of PM emissions. If electing to comply with an opacity limit in lieu of operating parameters for an ESP or fabric filter, a COMS must be installed, operated, certified, and maintained according to the Performance Specification 1 at 40 CFR Part 60, Appendix B. Use of opacity as an PM indicator, requires the following:

- Establish a site-specific maximum opacity level using data from the opacity monitoring system during the PM performance test. Opacity readings must be collected every 15 minutes during the entire period of the performance tests. Determine the average hourly opacity reading by computing the hourly averages using all of the 15 minute readings taken during each performance test. Determine the highest hourly average opacity reading measured during the test run demonstrating compliance with the PM (or TSM) emission limitation.
- Maintain opacity to less than or equal to 10 % daily block average or the highest hourly average opacity reading measured during the most recent performance test, or the highest hourly average Opacity reading measured during the most recent performance test run demonstrating compliance with the PM (or TSM) emission limitation.

If the boiler or process heater has an applicable emission limit for Hg and operating limits are based on use of a Dry Scrubber or Carbon Injection may be used and is described below.

Establishing Operating Limits if Dry Scrubber or Carbon Injection is being used for Compliance (if not using Hg CEMS)

– Dry scrubber for Hg is an add-on air pollution control system that injects or sprays an activated carbon (or similar material) into the gas stream to react with and/or absorb Hg forming a dry powder material. A dry scrubber is a dry control system.

- Establish the minimum activated carbon injection rate, as defined in §63.7575, as the operating limit during the three-run performance test. Establish a site-specific minimum activated carbon injection rate operating limit according to §63.7530(b) using data from the activated carbon rate monitors and Hg performance test. Collect activated carbon injection rate data every 15 minutes during the entire period of the performance tests. Determine the hourly average activated carbon injection rate by computing the hourly averages using all of the 15 minute readings taken during each performance test. Determine the lowest hourly average established during the performance test as the operating limit. When the unit operates at lower loads, multiply the activated carbon injection rate by the load fraction as defined in §63.7575 to determine the required injection rate.
- Maintain minimum activated carbon/sorbent injection rate.
 - The Minimum activated carbon injection rate is the load fraction multiplied by the lowest hourly average activated carbon injection rate measured according to Table 7 to Subpart DDDDD during the most recent performance test demonstrating compliance with the applicable emission limit. The minimum activated carbon/sorbent injection rate is:
 - The load fraction multiplied by the lowest hourly average sorbent injection rate for each sorbent measured according to Table 7 to Subpart DDDDD during the most recent performance test demonstrating compliance with the applicable emission limits; or

- For fluidized bed combustion, the lowest average ratio of sorbent to sulfur measured during the most recent performance test.

If the boiler or process heater has an applicable emission limit for HCl and operating limits are based on use of a Wet or Dry Scrubber, or a SO₂ CEMS. These control devices are described below.

Establishing Operating Limits if a Wet Acid Gas (HCl) Scrubber is used for Compliance (If not using HCl CEMS) – An add-on air pollution control device that mixes an aqueous stream or alkaline slurry with the exhaust gases from a boiler or process heater to control emissions or to absorb and neutralize acid gases, such as HCl. Alkaline reagents include, but not limited to, lime, limestone and sodium. The following considerations must be taken when using a Wet HCl Scrubber:

- Establish site-specific minimum effluent pH and flow rate operating limits according to §63.7530(b) using data from the pH and liquid flow-rate monitors and the HCl performance test. Collect pH and liquid flow-rate data every 15 minutes during the entire period of the performance tests. Determine the hourly average pH and liquid flow rate by computing the hourly averages using all of the 15 minute readings taken during each performance test.
- The pH monitoring system must be calibrated in accordance with the monitoring plan at least once each process operating day. [§63.7525(g)(3)]
- Maintain 30-day rolling average block average effluent pH and 30-day rolling average liquid flow rate at or above lowest 1-hour averages established during most recent Performance Test.

Establishing Operating Limits if Dry Scrubber or Sorbent Injection is used for Compliance (if not using HCl CEMS) – An add-on air pollution control system that injects dry alkaline sorbent (dry injection) or sprays an alkaline sorbent (spray dryer) to react with and neutralize acid gas in the exhaust stream forming a dry powder material. The following considerations must be taken when using a Dry Scrubber or Sorbent Injection:

- Establish a site-specific minimum sorbent injection rate operating limit according to §63.7530(b). If different acid gas sorbents are used during the HCl performance test, the average value for each sorbent becomes the site-specific operating limit for that sorbent using data from the sorbent injection rate monitors and HCl or Hg performance test. Collect the sorbent injection rate data every 15 minutes during the entire period of the performance tests. Determine the hourly average sorbent injection rate by computing the hourly averages using all of the 15 minute readings taken during each performance test. Determine the lowest hourly average of the three test run averages established during the performance test as the operating limit. When the unit operates at lower loads, multiply the sorbent injection rate by

the load fraction (e.g., for 50 percent load, multiply the injection rate operating limit by 0.5) to determine the required injection rate.

Establishing Operating Limits if SO₂ CEMS is used for Compliance – SO₂ CEMS is an alternative to HCl compliance. For boilers or process heaters subject to an HCl emission limit that demonstrates compliance with an SO₂ CEMS (must also have a system using wet scrubber or dry sorbent injection installed on the boiler or process heater). The following considerations must be taken when using a SO₂ CEMS:

- The monitor must be installed at the outlet of the boiler or process heater, downstream of all emission control devices.
- Install, certify, operate, and maintain the SO₂ CEMS according to either 40 CFR 60 or 40 CFR 75.
- A unit-specific maximum SO₂ operating limit must be established by collecting the maximum hourly SO₂ emission rate on the SO₂ CEMS during the paired 3-run test for HCl. The maximum SO₂ operating limit is equal to the highest hourly average SO₂ concentration measured during the most recent HCl performance test.
- Maintain the 30-day rolling average SO₂ emission rate at or below the highest hourly average SO₂ concentration measured during the HCl performance test, as specified in Table 8 to Subpart DDDDD.

If the boiler or process heater has an applicable emission limit for CO, the following must be considered:

Install, operate, and maintain a continuous oxygen monitor at the outlet of the boiler.

OR

If electing to comply with the alternative CO CEMS emission standard, install, certify, operate, and maintain a CO CEMS and an oxygen (or CO₂) analyzer according to the procedures under Performance Specification 4, 4A, or 4B at 40 CFR Part 60, Appendix B.

If the boiler or process heater has an applicable emission limit for CO for which compliance is demonstrated by a performance test and operating limits are based on the following.

Oxygen -

- Establish a unit-specific limit for minimum oxygen level according to §63.7530(b) using data from the Oxygen Analyzer System. Minimum oxygen level is the lowest hourly average oxygen level measured according to Table 7 to Subpart DDDDD during the most recent performance test demonstrating compliance with the applicable emission limit. If multiple performance tests

are conducted, set the minimum oxygen level at the lower of the minimum values established during the performance tests.

- Oxygen data must be collected every 15 minutes during the entire period of the performance tests. Determine the hourly average oxygen concentration by computing the hourly averages using all of the 15 minute readings taken during each performance test. Determine the lowest hourly average established during the performance test as the minimum operating limit.

Establishing Operating Limits if an Oxygen Analyzer System is being used for Compliance -

All equipment required to determine the oxygen content of a gas stream and used to monitor oxygen in the boiler or process heater flue gas, boiler or process heater, firebox, or other appropriate location. This definition includes oxygen trim systems.

Oxygen trim system is a system of monitors that is used to maintain excess air at the desired level in a combustion device over its operating load range. A typical system consists of a flue gas oxygen and/or CO monitor that automatically provides a feedback signal to the combustion air controller or draft controller. Implementation of the system considers the following:

- For boilers and process heaters subject to a CO emission limit that demonstrate compliance with an Oxygen Analyzer System as specified in §63.7525(a). This requires user to maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen concentration measured during the most recent CO performance test, as specified in Table 8 to Subpart DDDDD. This requirement does not apply to units that install an oxygen trim system since these units will set the trim system to the level specified in §63.7525(a).
- 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. If the facility is not required to conduct a performance test on the boiler or process heater, set the oxygen level to the oxygen concentration measured during the most recent tune-up to optimize CO to manufacturer's specification.

All other dry add-on air pollution controls (if PM CPMS is not used) - *This option is for boilers and process heaters that operate dry control systems.*

- Existing and new boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity or the highest hourly average opacity reading measured during the performance test run demonstrating compliance with the PM (or TSM) emission limitation (daily block average).

The boiler or process heater uses a Performance (stack) Test for to demonstrate compliance with an applicable limit – The operating load must be monitored based on the operating limit set during the most recent PM performance test. To maintain compliance, user must:

- Maintain the 30-day rolling average operating load of each unit such that it does not exceed 110 percent of the highest hourly average operating load recorded during the most recent performance test.

4.3.8 Task 8: Conduct Performance Evaluation of any CMS

This section includes general information on how to perform the performance evaluation of CMS during the performance testing. Additional information is provided in Appendix E of this Guide, *Performance Testing*

CMS – CMS includes a variety of emissions monitoring equipment; CPMS, CEMS, Oxygen Trim Systems, etc. Additional information regarding CMS (types, definitions, etc.) is available in the compliance strategy section. *CMS performance evaluations must be conducted as outlined and described in the site-specific monitoring plan.*

NOTE: Boilers and process heaters that use a CEMS are exempt from the Performance Testing and operating limit requirements specified in paragraph (a) of §63.7510 for the HAP for which CEMS are used [40 CFR 63.7510(b)]. Facilities can elect to use CEMS to directly measure emissions from the affected boilers and process heaters. Data will be obtained and the necessary rolling average will be collected to demonstrate that the emissions are less than the applicable emission limits. Although a performance test is not required for a particular pollutant if using a CEMS, a performance evaluation will need to be completed to ensure that the CEMS is calibrated and operating correctly.

All CMS must be installed, operational, and the data verified, as specified in 40 CFR 63.8 and Subpart DDDDD, either prior to or in conjunction with conducting Performance Tests in accordance with 40 CFR 63.7 and §63.7520. A performance evaluation of each CMS, including a Relative Accuracy Test Audit, must be completed in accordance with the site-specific monitoring plan (and according to §63.7525).

4.3.8.1 Compliance with CO Emission Limit

- If the boiler or process heater has a CO emission limit, a continuous CO monitor must be installed, operated, and maintained at the outlet of the boiler. A performance evaluation of the continuous CO monitor is required in accordance with §63.7525(a).

OR

- If electing to comply with the alternative CO CEMS emission limit, install, certify, operate, and maintain a CO CEMS and an oxygen (or carbon dioxide) analyzer according to the procedures under Performance Specification 4, 4A, or 4B at 40 CFR Part 60, Appendix B. The CO and oxygen (or CO₂) levels shall be monitored at the same location at the outlet of the boiler or process heater.

NOTE: Boilers and process heaters that use a CO CEMS to comply with the applicable alternative CO CEMS emission standard listed are exempt from the initial CO performance testing and the oxygen concentration operating limit.

- For the alternate CO CEMS emission limit, an alternative test method may be requested under §63.7. in order for compliance with the CO emissions limit be determined using CO₂ as a diluent correction in place of oxygen at 3%. EPA Method 19 F-factors and EPA Method 19 equations must be used to generate the appropriate CO₂ correction percentage for the fuel type burned in the unit, and must also take into account that the 3% oxygen correction is to be done on a dry basis. The alternative test method request must account for any CO₂ being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc... [§63.7525 (a)(1)]
- 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. Acceptable continuous moisture monitoring systems include: 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 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. [§63.7525 (a)(2)(vi)]

4.3.8.2 Compliance with Opacity

- If electing to comply with an opacity limit in lieu of operating parameters for an ESP or fabric filter, a COMS must be installed, operated, certified, and maintained according to the Performance Specification at 40 CFR Part 60, Appendix B.

If the Boiler or Process Heater uses a Fabric Filter -

- If electing to use a fabric filter to comply with an emission limit, a bag leak detection system must be installed, calibrated, maintained, and continuously operated.

OR

- Maintain opacity to less than or equal to 10 % daily block average or the highest hourly average opacity reading measured during the most recent performance test.

4.3.8.3 PM CPMS Requirements

If the boiler or process heater is in the “Unit Designed to Burn Coal/Solid Fossil Fuel” subcategory or the “Unit Designed to Burn Heavy Liquid” subcategory and has an average annual heat input rate greater than 250 MMBtu/hr from solid fossil fuel and/or heavy liquid, installment of either an PM CPMS or a PM CEMS is required. [§63.7525(b)(4) & §63.7525 (b)(8)]

Compliance is demonstrated with the PM limit instead of the alternative TSM limit. An PM CPMS must be installed, maintained, and operated according to the procedures in the approved site-specific monitoring plan and the requirements in §63.7525(b). *The PM CPMS must have a documented detection limit of 0.5 milligram per actual cubic meter, or less* [§63.7525(1)(iii)].

When a deviation occurs, a PM performance test is required within 30 days or at the time of the annual compliance test, whichever comes first to determine compliance with the PM emissions limit and to verify or re-establish the CPMS operating limit. Additional testing for deviations is not required between the time of the deviation and the PM emissions compliance test required due to a deviation.

NOTE: PM CPMS deviations from the operating limit leading to more than four required performance tests in a 12-month operating period constitute a separate violation of Subpart DDDDD [§63.7540(a)(18)(ii-iii)].

4.3.8.4 CMS Maintenance

A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures can be caused in part by poor maintenance. Scheduled CMS maintenance is usually defined in the site-specific monitoring plan. At a minimum, CMS shall be maintained and operated as follows [40 CFR 63.8(c)(1) through (4) and 40 CFR 63.8(g)(2)]:

- If the boiler or process heater has an operating limit that requires a CMS, the CMS must be installed, operated, and maintained.

- The CMS shall be maintained and operated each CMS in a manner consistent with safety and good air pollution control practices for minimizing emissions, in accordance with 40 CFR 63.6(e)(1).
- The necessary parts for routine repairs and maintenance of the CMS equipment shall be kept readily available.
- Installation of the CMS sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (e.g., on or downstream of the last control device) and according to the procedures documented in the applicable performance specification.
- Any CPMS shall be installed to accurately measure the process and/or the control device parameters.
- Verification of the operational status of each CMS shall include the completion of the manufacturer's written specifications or the recommendations for installation, operation, and calibration of the system.
- The read out, (the visual display or measured record of the CMS) or other indication of operation, from any CMS required for compliance with the emission standard, shall be readily accessible for operational control and visible for monitoring and recording by the operator of the equipment.
- Except for system breakdowns, out-of-control periods, repairs, maintenance periods, calibration checks, and zero (low-level) and high-level calibration drift adjustments, all CMS shall be maintained in continuous operation as follows:
 - All COMS shall complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6 minute period.
 - All CEMS for measuring emissions other than opacity shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

4.3.9 Task 9: Prepare and Submit Notification of Compliance

After all initial compliance tasks are completed, submit an initial Notification of Compliance Status (NOCS) to the Administrator with all information in §63.9(h)(2)(ii) and §63.7545(e) to the

Administrator (additional details of the NOCS is provided in Chapter 6 of this Guide). The initial NOCS should include, at at minimum and depending on the compliance requirements:

- Relevant emission limits.
- Compliance demonstration results (performance testing, fuel analysis, etc.).
- Established operating limits.
- Certification of compliance status with emission limits, operating limits, and work practices.

5 CONTINUOUS COMPLIANCE

NOTE: Ensure that the boiler or process heater continues to meet the applicable fuel subcategory definition. It is particularly important for multi-fueled boilers and process heaters to calculate annual heat input before every compliance demonstration (e.g. tune-up or Performance Test) to confirm the boiler or process heater is complying with requirements of the correct fuel subcategory.

After initial compliance is completed, compliance with the work practice standards in Table 3 must be conducted on a periodic or ongoing basis as required. Boilers and process heaters subject to emission limits must demonstrate continuous compliance with each Emission Limit in Table 1 or Table 2 of Subpart DDDDD. Additionally, the operating limits in Table 4 to Subpart DDDDD shall be demonstrated in accordance with the methods specified in §63.7540(a) and Table 8 to Subpart DDDDD.

Additionally, subsequent Performance Tests and Fuel Analysis will also be required in many circumstances for boilers and process heaters subject to emission limits unless a CEM is utilized. Boilers and process heaters subject to emission limits must demonstrate compliance with all applicable emission limits using:

- Fuel Analysis:
 - Compliance with the applicable emission limit for HCl, Hg, or TSM may be demonstrated using fuel analysis if the emission rate calculated according to §63.7530(c) is less than the applicable emission limit.
 - For gaseous fuels, fuel analyses may NOT be used to comply with the TSM alternative standard or the HCl standard.
- CMS, including a CEMS, COMS, CPMS, or PM CPMS, where applicable.
- Performance (Stack) Testing:
 - If not using Fuel Analysis or CMS to demonstrate compliance, compliance for HCl, Hg, or TSM must be demonstrated using performance stack testing.

Records must be kept of the type and amount of all fuels burned in each boiler or process heater during the reporting period to demonstrate that all fuel types and mixtures of fuels burned would result in either of the following:

- Lower emissions of HCl, Hg, and TSM than the applicable emission limit for each pollutant, if compliance is demonstrated through fuel analysis.
- Lower fuel input of chlorine, Hg, and TSM than the maximum values calculated during the last performance test, if compliance is demonstrated through performance testing.

5.1.1 Task 1: Conduct Periodic Tune-ups

Following the initial tune-up, existing sources will undergo regularly scheduled tune-ups. The subsequent tune-up must be conducted the first tune-up no later than 13 months, 25 months, or 61 months after the initial tune-up, depending on the tune-up schedule applicable to that particular boiler or process heater.

New and reconstructed boilers and process heaters are not required to undergo an initial tune-up, but the first tune-up must be conducted no later than 13 months, 25 months, or 61 months after start-up, whichever is applicable. The tune-up schedule is dependent on the fuel subcategory of the boiler or process heater. The tune-ups must be conducted for each boiler within the applicable annual, biennial, or 5-year schedule as specified in 40 CFR 63.7500(c), (d), and (e), 40 CFR 63.7540(a)(10) through (13), and Table 3 of Subpart DDDDD (as summarized in Tables 5-1 and Table 5-2 below):

Table 5-1. Periodic Tune-Up Schedule

PERIODIC TUNE-UP SCHEDULE	
If the boiler or process requires a tune-up...	Conduct a tune-up and inspection....
Every Year	No later than 13 months after the previous tune-up and inspection.
Every 2 Years	No later than 25 months after the previous tune-up and inspection.
Every 5 Years	No later than 61 months after the previous tune-up and inspection.
40 CFR 63.7500(c), (d), and (e), 40 CFR 63.7510(e), (g) and (j)], 40 CFR 63.7515(d) and (g), 40 CFR 63.7540(a)(10) through (13)	

Table 5-2. Tune-up Schedule by Boiler or Process Heater Fuel Subcategory

Boiler/Process Heater Factors		Tune-Up Schedule (Initial Tune-up required for existing units)
Heat Input Capacity (MMBtu/hr)	Fuel Classification	
≤ 5	Gas 1	Every 5 Years
	Gas 2	
	Light Liquid	
≤ 5	Biomass, Coal	Every 2 Years
	Heavy Liquid	
>5 and <10	Gas 1	
	Gas 2	
	Coal, Biomass	
	Light Liquid	
	Heavy Liquid	
≥ 10	Gas 1	Every Year
≥ 10	Gas 2	
	Coal, Biomass	
	Light Liquid	
	Heavy Liquid	
All Limited Use		Every 5 Years
All Units with an Oxygen Trim System		

If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 days of start-up.

5.1.2 Task 2: Conduct Subsequent Performance (Stack) Testing if Required

NOTE: This task applies to boilers and process heaters subject to emission limits and complying those limits through Performance (stack) Testing.

A facility is required to conduct initial and annual stack-emissions tests on each boiler for PM, HCl, Hg, and CO to demonstrate compliance with the emission limits and establish each boiler or process heater's operating limits, where applicable. As an alternate method of demonstrating compliance with Hg, HCl, or TSM emissions limits, a facility may conduct fuel-analysis testing.

NOTE: Verification of an existing operating limit or establishment of a new operating limit is required after each repeated performance test. Impementation of performance testing is described below.

Light Liquid Fuel Boilers and Process Heaters - Following an initial compliance Performance Test, further Performance Tests are not required for a boiler designed to burn light liquid fuels and that only burns Ultra-Low Sulfur Liquid Fuel (ULSD), if the fuel is monitored and monthly records can demonstrate that only ULSD fuel is burned in the boiler.

Frequency of Performance Testing - Performance testing must be conducted on an annual basis per §63.7520 and completed no more than 13 months after the previous Performance Test. However, if it can be demonstrated that compliance has been ongoing, Performance Testing can occur less frequently (the reduced testing frequency does not apply if the facility is averaging emissions):

- If after two consecutive years the emissions of a pollutant identified in Tables 1 or 2 (as applicable) are at or below 75% of the emissions limit for that pollutant and there have been no changes in the operation of the boiler or air pollution control equipment that could increase emissions, Performance Testing may revert to every 3 years, or no more than 37 months after the previous test, for the pollutant.
- If the pollutant exceeds 75% of the applicable limit, testing shall revert back to annual testing until the Performance Tests over another consecutive two-year period have demonstrated the emissions to be at or below 75% of the applicable Emission Limit identified in Table 1 or 2.
- For each existing boiler in which compliance is demonstrated through emissions averaging, Performance Testing shall remain on an annual basis. The average operating load must be recorded during each Performance Test.

5.1.3 Task 3: Conduct Periodic Fuel Analysis

NOTE: This task applies to boilers and process heaters subject to emission limits and complying those limits through Fuel Analysis.

If compliance is demonstrated with the Hg, HCl, or TSM emission limits based on fuel analysis, a monthly fuel analysis must be conducted according to §63.7521 for each type of fuel burned that is subject to an emission limit. To use this alternative:

- Demonstrate that the calculated emission rate according to §63.7521(e) and Equation 15 of Subpart DDDDD is less than the Hg, HCl, or TSM emission limit.
- Collect monthly fuel analyses.

- Calculate 12-month rolling averages.
- Maintain 12-month rolling average at or below the applicable Emission Limit.
- Fuel analysis may not be used for gaseous fuels to comply with the TSM alternative standard or the HCl standard.

The facility 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.

Frequency of fuel analyses can be decreased (all applicable continuous compliance requirements in §63.7540 must continue to be met) if each of the 12 consecutive monthly fuel analyses demonstrates 75 percent or less of the compliance level, the fuel analysis frequency may be decreased to quarterly for that fuel. However, if any quarterly sample exceeds 75 percent of the compliance level or a new type of fuel is being burned, monthly monitoring for that fuel must resume, until 12 months of fuel analyses are again less than 75 percent of the compliance level.

If planning to burn a new type of fuel or fuel mixture, a fuel analysis must be conducted before burning the new fuel or mixture in the boiler or process heater. Recalculate the Hg, HCl, or TSM emission rate according to §63.7521 and Equation 15 of Subpart DDDDD. The recalculation must demonstrate:

- The resulting Hg, HCl, or TSM emission rate for the new type of fuel or fuel mixture must be less than the applicable emission limit.
- If the pollutant concentration for the new fuel type or mixture is higher than for the fuel used during the previous performance test, then a new performance test must be conducted within 60 days of burning the new fuel type or mixture.

To complete each fuel analysis:

- Obtain at least three composite fuel samples for each fuel type according to the procedures in Table 6 to Subpart DDDDD.
- Each composite sample must consist of a minimum of three samples collected at approximately equal intervals during a two-hour period.

- Determine the concentration of Hg, HCl, or TSM in the fuel in units of lb/MMBtu of each composite sample for each fuel type according to the procedures in Table 6 to Subpart DDDDD

Additional guidance on Fuel Analysis, including specific procedures, can be found at §63.7521 of Subpart DDDDD and in the Appendix of this Guide.

5.1.4 Task 4: Continuous Compliance with Emission and Operating Limits

NOTE: This task applies to boilers and process heaters subject to emission limits.

In addition to complying with work practice standards and conducting periodic stack tests and fuel analysis, a facility must demonstrate continuous compliance by monitoring and complying with applicable site-specific operating limits established during the performance tests or fuel analysis. Continuously monitoring of operating parameters is conducted according to the methods in Table 8 of Subpart DDDDD. The applicable monitoring system(s) must be operated and the data collected at all times the boiler or process heater is operating. All of the data collected is used in assessing the operation of the control device and associated control system. The facility must monitor and collect data according to §63.7535 and the required site-specific monitoring plan.

Failure to collect required data is a deviation of the monitoring requirements. Data cannot be used to demonstrate compliance during:

- Startup and shut-down.
- Monitoring system malfunctions or out-of-control periods.
- Required monitoring system quality assurance or quality control activities, including calibration checks and required zero and span adjustments.
- Repairs associated with monitoring system malfunctions or out-of-control periods.

In cases of monitoring system malfunctions or out-of-control periods, the repairs to the monitoring system must be made and the monitoring system returned to operation as quickly as possible. A CMS is out of control if:

- The zero (low-level), mid-level (if applicable), or high-level Calibration Drift (CD) exceeds two times the CD specification in the applicable performance specification or relevant standard; or
- The CMS fails a performance test audit, relative accuracy audit, relative accuracy test audit, or linearity test audit; or

- The COMS CD exceeds two times the limit in the applicable performance specification in the relevant standard.

A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused by poor maintenance or careless operation are not malfunctions. [§63.7535(b)]

A deviation is any instance in which an affected source subject to Subpart DDDDD, or an owner or operator of such a source (a deviation is not always a violation):

- Fails to meet any applicable requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard; or
- Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit. (§63.7575)

A record must be made (and made available upon request) of CMS performance audit results and dates and duration of periods when the CMS is out of control to completion of the corrective actions necessary to return the CMS to operation consistent with the site-specific monitoring plan.

CO Continuous Compliance Monitoring

If the boiler or process heater is subject to a CO emission limit, the facility must:

Install, operate, and maintain an oxygen analyzer system.

OR

Install, certify, operate and maintain CEMS for CO and oxygen (or CO₂).

- Boilers and process heaters that use CO CEMS must comply with the alternate CO CEMS based limits.
- Boilers and process heaters that use CO CEMS are exempt from initial CO performance testing and oxygen operating limits.
- Must calculate hourly averages, corrected to 3 percent oxygen, and determine the 30 or 10-day rolling average.
- An alternative test method may be requested to comply with the CO emissions limit using CO₂ as a diluent correction in place of oxygen at 3 percent. EPA Method 19 F-factors and EPA Method 19 equations must be used to generate the appropriate CO₂ correction percentage for the fuel type burned in the unit. Additionally, the correction must also take into account that the 3 percent oxygen correction is to be done on a dry basis. The alternative test method request must

account for any CO₂ being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc.

- 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 lookup 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.

Opacity -- Opacity means the degree to which emissions reduce the transmission of light and obscure the view of an object in the background. Opacity is usually measured as a percent, where zero percent opacity means completely transparent and 100 percent opacity means completely opaque.

- Collect opacity data.
- Calculate 6-minute averages.
- Maintain opacity at 10 percent or less on a daily block average basis or the highest hourly average opacity reading measured during the most recent performance test.

Fabric Filter Bag Leak Detection --

- Install, maintain, calibrate and operate the bag leak detection system.
- Operate the fabric filter such that the bag leak detection system alarm does not sound more than 5 percent of the operating time during a 6-month period.
- Initiate corrective action within 1 hour of alarm sounding. Keep records of corrective action.

Wet Scrubber Pressure Drop and Liquid Flow Rate --

- Collect pressure drop and liquid flow rate CMS data.
- Calculate 30-day rolling averages.*
- Maintain 30-day rolling average at or above the operating limits from the Performance Test.

Wet Scrubber Pressure pH --

- Collect pH CMS data.
- Calculate 30-day rolling averages.*
- Maintain 30-day rolling average at or above the operating limits from the Performance Test.

Dry Scrubber Sorbent or Carbon Injection Rate --

- Collect injection rate CMS data.
- Calculate 30-day rolling averages.*
- Maintain 30-day rolling average at or above the operating limits from the Performance Test.

ESP Total Secondary Electric Power Input --

- Collect total secondary electric power input CMS data.
- Calculate 30-day rolling averages.*
- Maintain 30-day rolling average at or above the operating limits from the Performance Test.

Oxygen Content --

- Collect the exhaust oxygen content CMS data.
- Calculate 30-day rolling averages.*
- Maintain 30-day rolling average at or above the operating limits from the Performance Test.

Operating Load --

- Collect operating load data or steam generation data every 15 minutes.
- Reduce the data to 30-day rolling averages*.
- Maintain the 30-day rolling average* operating load such that it does not exceed 110 percent of the highest hourly average operating load recorded during the performance test according to §63.7520(c).

Fuel Analysis --

- Collect monthly fuel analyses.
- Calculate 12 month rolling averages.
- Maintain 12 month rolling average at or below the applicable emission limit.

- Calculate the HCl, Hg, and/or TSM emission rate from the boiler or process heater in units of lb/MMBtu using Equation 15 and Equations 17, 18, and/or 19 in §63.7530.

PM CPMS --

- Units in the coal or heavy liquid subcategories and have a heat input capacity greater than 250 MMBtu/hr that demonstrate compliance with the PM limit instead of the TSM limit must install and operate a PM CPMS or install and maintain a PM CEMS [§63.7525(b)].
- PM CPMS must have a cycle time no longer than 60 minutes.
- Deviations leading to 4 required performance tests in a 12- month period constitute a violation. (§63.7540(a)(18)(iii)).
- Collect the PM CPMS output data.
- Calculate 30-day rolling averages.*
- Maintain 30-day rolling average* at or below the operating limits from the Performance Test.

If no control device is used to demonstrate compliance with the PM limit, operating load must be monitored based on the operating limit set during the most recent PM performance test (Table 4, Item 7 and Table 8, Item 10 to Subpart DDDDD).

SO₂ CEMS --

- Collect the SO₂ CEMS output data.
- Calculate 30-day rolling averages.*
- Maintain 30 day rolling average* at or below the highest operating limits from the HCl performance test according to §63.7530.

*30-day rolling average means the arithmetic mean of the previous 720 hours of valid CO CEMS data. The 720 hours should be consecutive, but not necessarily continuous if operations were intermittent. For parameters other than CO, 30-day rolling average means either the arithmetic mean of all valid hours of data from 30 successive operating data days or the arithmetic mean of the previous 720 hours of valid operating data. Valid data excludes hours during start-up and shut-down, data collected during periods when the monitoring system is out-of-control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities, and periods when this unit is not operating

6 NOTIFICATIONS AND REPORTS

This section addresses the additional reporting and notifications required after the compliance date.

NOTE: Notifications, reports, and certifications requiring the signature of a “Responsible Official” must be signed by the Installation/Center Commander per CFR §70.2 and AFI 32-7040, Air Quality Compliance and Resource Management.

6.1 Notification of Compliance Status

The Notification of Compliance Status certifies that the facility is in compliance with all the requirements of the rule. An initial Notification of Compliance status report **MUST** be submitted before the close of business on the 60th day following the completion of performance tests and/or other initial compliance demonstrations for all boiler or process heaters at the facility. This includes tune-ups, energy assessments, and performance tests, where applicable. If the boiler or process heater is subject to emissions limits, include all performance test results and fuel analyses.

It is important to note that the Initial Notification of Compliance Status must be submitted no more than 60 days after the completion of the compliance demonstrations for the **last** affected boiler or process heater, including those with a 1-year extension. §63.7545(e)

In addition to the information required in 40 CFR 63.9(h)(2), the notification of compliance status must include the following certifications of compliance, as applicable, and signed by a responsible official: [§63.7545(e)(8)]

- “This facility complies with the required initial tune-up according to the procedures in §63.7540(a)(10)(i) through (vi)” [§63.7545(e)(8)(i)].
- “This facility has had an energy assessment performed according to §63.7530(e)” [§63.7545(e)(8)(ii)].
- Except for units that burn only natural gas, refinery gas, or other Gas 1 fuel, or units that qualify for a statutory exemption as provided in Section 129(g)(1) of the CAA, include the following: “No secondary materials that are solid waste were combusted in any affected unit” [§63.7545(e)(8)(iii)].

If the boiler or process heater is subject to emission limits in Subpart DDDDD, the following information must be included, as applicable:

- A description of the affected unit(s) including identification of the unit’s subcategories, the design heat input capacity of the unit, a description of the add-on controls used to

comply with this subpart, description of the fuel(s) burned, including if the fuel(s) were a secondary material determined to be a non-waste under § 241.3, and justification for the selection of fuel(s) burned during the compliance demonstration.

- Include a summary of the results of all performance tests and fuel analyses, and calculations done to demonstrate initial compliance including all established operating limits. If data from a previously conducted emission test is used as documentation of compliance with the emission standards and operating limits of this rule, then submit the previous test data instead of the initial performance test results with the Notification of Compliance Status.
- The following information is also required:
 - Identification of whether or not the facility is complying with the PM emission limit or the alternative TSM emission limit.
 - Identification of whether or not the facility is complying with the output-based or heat input-based (i.e., lb/MMBtu or parts per million (ppm)) emission limits.
 - A summary of the maximum CO emission levels recorded during the performance test to show any applicable emission standards in Table 1 or Table 2 of Subpart DDDDD have been met, if not using a CO CEMS for compliance.
 - Identification of whether or not compliance is demonstrated with each applicable emission limit through performance testing, a CEMS, or fuel analysis.
 - Identification of whether or not compliance is demonstrated by emissions averaging or using efficiency credits through energy conservation.
 - A signed certification that you have met all applicable emission limits and work practice standards.
 - If there was a deviation from any emission limit, work practice standard, or operating limit, include a description of the deviation, the duration of the deviation, and the corrective action taken.

If using data from a previously conducted emission test to serve as documentation of compliance with the emission standards and operating limits of this rule, then the previous test data must be submitted instead of the initial performance test results with the Notification of Compliance Status.

Certification of Notification of Compliance – A signed certification must be included in the Notification of Compliance Status stating that either the energy assessment was completed

according to Table 3 to Subpart DDDDD. Additionally, the signed certification must show that the assessment is an accurate depiction of the facility at the time of the assessment, or that the maximum number of on-site technical hours specified in the definition of energy assessment applicable to the facility has been expended.

If the facility owns or operates an existing boiler or process heater with a heat input capacity of less than 10 MMBtu/hr or a unit in the unit designed to burn Gas 1 subcategory, the facility NO LONGER is required to submit a signed statement in the Notification of Compliance Status report that indicates a tune-up was conducted on the unit. The EPA removed this requirement in the final rule published on 20 November 2015.

6.2 Compliance Report

The first semi-annual compliance report must cover the period beginning on the compliance date that is specified for each boiler or process heater in §63.7495 and ending on June 30 or December 31, whichever date is the first date that occurs at least 180 days after the applicable compliance date for the boiler or process heater. The first semi-annual compliance report must be postmarked or submitted no later than July 31 or January 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for each boiler or process heater in §63.7495 (for existing sources with emission limits, the date is 31 July 2016). The first annual, biennial, or 5-year compliance report must be postmarked or submitted no later than January 31.

Subsequent reports are due semi-annually, annually, biennially, or every five (5) years depending on the unit's compliance requirements. Boilers and process heaters subject only to an energy assessment and tune-up will only need an annual, biennial, or 5-year compliance report, depending on the applicable tune-up schedule. If the boiler or process heater is subject to emission limits, a semi-annual Compliance Certification Report must be postmarked or submitted by July 31 and January 31 of each year for the previous semi-annual reporting period.

The report must contain, as applicable to the boiler or process heater:

- The company name and address.
- Process unit information, emissions limitations, and operating parameter limitations.
- If using a CMS, including CEMS, COMS, or CPMS, the monitoring equipment manufacturer(s) and model numbers and the date of the last certification or audit.

- The total fuel use by each individual boiler or process heater subject to an Emission Limit within the reporting period, including a description of the fuel.
- If conducting Performance Tests every 3 years, the date of the last 2 Performance Tests and a statement if there have been any operational changes that could increase emissions.
- A statement indicating that no new types of fuel was burned in any boiler or process heater subject to an emission limit. Or, if new type of fuel was burned and subject to emission limits, submit the calculation of chlorine, Hg, or TSM input that demonstrates that the source is still within the maximum chlorine, Hg, or TSM input level established during the previous Performance Testing (for sources that demonstrate compliance through Performance Testing). Or you must submit the calculation of HCl, Hg, or TSM emission rate that demonstrates that your source is still meeting the Emission Limit for HCl, Hg, or TSM emissions (for boilers or process heaters that demonstrate compliance through fuel analysis).
- A summary of any monthly fuel analyses conducted to demonstrate compliance for individual boilers or process heaters subject to emission limits.
- If there are no deviations from any applicable emission limits or operating limits, a statement that there were no deviations from the emission limits or operating limits during the reporting period.
- If there were no deviations from the monitoring requirements, a statement that there were no deviations and no periods during which the CMS were out-of-control during the reporting period.
- The date of the most recent tune-up for each unit subject to the requirement to conduct an annual, biennial, or 5-year tune-up. Include the date of the most recent burner inspection if it was not done annually, biennially, or on a 5-year period and was delayed until the next scheduled or unscheduled unit shut-down.
- If you demonstrate compliance by emission averaging, a certification that the emission level achieved or the control technology employed is no less stringent than the level or control technology contained in the notification of compliance status.
- All of the calculated 30-day rolling average values for each reporting period based on the daily CEMS and CPMS data.
- A statement by a responsible official certifying the truth, accuracy, completeness of the certification, and a statement of whether the source has complied with all the

relevant standards and requirements of the rule. The statement needs to also supply the official's name, title, phone number, e-mail address, and signature.

Facilities must identify deviations from required work practice standards during periods of start-up and shut-down in the compliance report.

For each affected source that is subject to permitting regulations pursuant to 40 CFR Part 70 or 40 CFR Part 71, and if the permitting authority has established dates for submitting semi-annual reports pursuant to 70.6(a)(3)(iii)(A) or 71.6(a)(3)(iii)(A), the first and subsequent compliance reports may be submitted according to the dates the permitting authority has established in the permit instead of according to the dates in paragraphs (b)(1) through (4) of this section.

6.2.1 Tune-up and Energy Assessment Reporting

Normally, the results of the energy assessment or tune-up are not required to be submitted. These items must be kept as records and submitted if requested by the Administrator.

6.2.2 Stack Test Performance Data Reporting

If the boiler or process heater is subject to performance (stack) testing, submit:

- The results of the Performance Tests, including any fuel analyses and compliance reports, within 60 days of completing each Performance Test electronically to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) which is accessed through the EPA's Central Data Exchange (CDX) (www.epa.gov/cdx).
- The Performance Test data in the format generated through the EPA's Electronic Reporting Tool (ERT) (see <http://www.epa.gov/ttn/chief/ert/index.html>). Only data collected using test methods on the ERT Web site must be submitted electronically to WebFIRE.

If some of the information being submitted for Performance Tests is Confidential Business Information (CBI), submit a complete ERT file. This submittal should include information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) to the EPA and/or the delegated Administrator. The same ERT file with the CBI omitted must be submitted to the EPA via Central Data Exchange.

For any Performance Test conducted using test methods that are not listed on the ERT Web site, submit the results on paper to the Administrator.

6.3 Other Required Notifications

6.3.1 Notification of Alternate Fuel Use [§63.7545(f)]

For units designed to burn natural gas, refinery gas, or “other Gas 1” fuels that is subject to Subpart DDDDD, if intending to use a fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart of Part 63, Part 60, 61, or 65, or other Gas 1 fuel to fire the affected unit during a period of natural gas curtailment or supply interruption, as defined in §63.7575, a Notification of Alternative Fuel Use must be submitted within 48 hours of the declaration of each period of natural gas curtailment or supply interruption, as defined in §63.7575. The notification must include the information specified in paragraphs (f)(1) through (5) of §63.7545:

- Company name and address.
- Identification of the affected unit.
- Reason facility was unable to use natural gas or equivalent fuel in the unit, including the date when the natural gas curtailment was declared or the natural gas supply interruption began.
- Type of alternative fuel that facility intends to use.
- Dates when the alternative fuel use is expected to begin and end.

6.3.2 Notification when Commencing or Recommencing Combustion of Solid Waste [§63.7545(g)]

If intending to commence or recommence combustion of solid waste, provide 30-days prior notice to Administrator. The notification must identify:

- The name of the owner or operator of the affected source, the location of the source, the boiler(s) that will commence burning solid waste, and the date of the notice
- The currently applicable subcategory under this subpart
- The date on which you became subject to the currently applicable emission limits
- The date upon which combusting solid waste will commence or recommence

6.3.3 Notification of Switching Fuels [§63.7545(h)]

If there was a switch in fuels or a physical change made to the boiler and this resulted in the applicability of a different subcategory, provide notice within 30 days of the switch/change. The notification must identify:

- The name of the owner or operator of the affected source, the location of the source, the boiler(s) and process heater(s) that have switched fuels, or were physically changed, and the date of the notice.
- The currently applicable subcategory under this subpart.

- The date on which you became subject to the currently applicable standards.
- The date upon which you the fuel switch or physical change occurred.

If a boiler or process heater would be subject to Boiler MACT, but it qualified for exemption (commercial and industrial solid waste incineration units covered by 40 CFR Part 60 Subpart CCCC or Subpart DDDD), and the boiler or process heater ceases combusting solid waste, then the boiler or process heater must be in compliance with Boiler MACT on the effective date of the fuel switch from solid waste.

6.4 How to Submit Notifications and Reports

EPA is no longer accepting paper submittals of the Notification of Compliance Status or other reports. The agency now requires the reports to be submitted electronically to CEDRI through EPA's Central Data Exchange.

- If the State has NOT been delegated authority to implement and enforce recordkeeping and reporting requirements, the owner or operator of an affected source in such State subject to such requirements shall submit reports to the appropriate Regional Office of the EPA (to the attention of the Director of the Division indicated in the list of the EPA Regional Offices in §63.13). [§63.10(a)(4)(i)]
- If the State has been delegated the authority to implement and enforce recordkeeping and reporting requirements, the owner or operator of an affected source in such State subject to such requirements shall submit reports to the delegated State authority (which may be the same as the permitting authority). In addition, if the delegated (permitting) authority is the State, the owner or operator shall send a copy of each report submitted to the State to the appropriate Regional Office of the EPA, as specified in paragraph (a)(4)(i) of this section. The Regional Office may waive this requirement for any reports at its discretion. [§63.10(a)(4)(ii)]

NOTE: For data collected using test methods supported by EPA's ERT, as listed on the ERT website, the test results must be submitted to EPA through CEDRI. As an alternative to submitting test data in a file format generated through ERT, a facility may submit an alternative electronic file format consistent with the Extensible Markup Language (XML) schema that will be listed on the ERT website as it becomes available. For data collected using test methods not supported by EPA's ERT (not listed on the ERT website), a facility must submit the test results to the Administrator at the appropriate address. A facility must begin submitting reports via CEDRI no later than 90 days after the relevant reporting form becomes available in CEDRI.

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7 RECORDKEEPING (§63.7555, §63.7560, AND §63.10)

Facilities subject to Boiler MACT have detailed recordkeeping and reporting requirements which are not only key to documenting compliance, updated and well-kept records can also provide detailed information regarding how well the boiler and control devices are operating. For example, a review of the parametric monitoring records can reveal patterns that may warn of a developing problem such as a significant change in the ESP voltage (which can indicate current or impending failure of the device).

7.1 Recordkeeping Duration and Method

Recordkeeping requirements begin when the record is created, which for most facilities, begins with the Initial Notice of Applicability. In accordance with §63.7560 and §63.10(b)(1), the records:

- Must be in a form suitable and readily available for expeditious review and inspection.
 - Files may be maintained on paper, on microfilm, on computer, on computer disks, on magnetic tape disks, or on microfiche.
- Must be kept on site or they must be easily accessible from the site (for example, through a computer network).
- Must be kept for 5 years after the date of each recorded action (occurrence, measurement, maintenance, corrective action, report, or record).
 - Keep each record on site for at least 2 years after the date of each recorded action.
 - For the remaining 3 of the 5 years, the records may be kept off site.

7.2 Types of Records to Maintain

The type of records to retain and manage will vary according to the specific compliance requirements of the boiler or process heater; however, most facilities will be required to maintain, at least, the following records:

- A copy of each notification and report submitted to comply with Boiler MACT, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that was submitted.
- Records of Performance Tests, fuel analyses, or other compliance demonstrations and performance evaluations (include all calculations and supporting documents).
 - The results from one fuel analysis for multiple boilers and process heaters can be used provided they are all burning the same fuel type. However, the fuel inputs (chlorine,

Hg, and/or TSM) or emission rates (HCl, Hg, and or TSM) MUST be calculated for each boiler and process heater, as applicable.

- Records of monthly fuel use by each boiler or process heater [include the type(s) of fuel and amount(s) used].
- Maintain records of the calendar date, time, occurrence and duration of each start-up and shut-down.
- Maintain records of the type(s) and amount(s) of fuels used during each start-up and shut-down.
- If the unit combusts NHSM, maintain any and all records documenting that the material is not solid waste.
- If the NHSM fuel received a non-waste determination pursuant to the petition process submitted under §241.3(c), keep a record that documents how the fuel satisfies the requirements of the petition process.
- For units in the limited use subcategory, keep a copy of the federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent and fuel use records for the days the boiler or process heater was operating.
- If emissions averaging consistent with §63.7522 is elected, keep a copy of the emission averaging implementation plan required in §63.7522(g), all calculations required under §63.7522, including monthly records of heat input or steam generation, as applicable, and monitoring records consistent with §63.7541.
- If efficiency credits from energy conservation measures is elected to demonstrate compliance according to §63.7533, keep a copy of the Implementation Plan required in §63.7533(d) and copies of all data and calculations used to establish credits according to §63.7533(b), (c), and (f).
- If electing to demonstrate that the unit meets the specification for Hg for the unit designed to burn Gas 1 subcategory, maintain monthly records [or at the frequency required by §63.7540(c)] of the calculations and results of the fuel specification for Hg as in Table 6 of Subpart DDDDD.
- Records of all monitoring data and calculated averages for applicable operating limits to demonstrate continuous compliance (opacity, pressure drop, pH, etc.).
- If, consistent with §63.7515(b), stack test occurs less frequently than annually, keep a record that documents that emissions from the previous stack test(s) were less than 75 percent of the applicable Emission Limit (or, in specific instances noted in Tables 1 and 2

of Subpart DDDDD, less than the applicable Emission Limit), and document that there was no change in source operations including fuel composition and operation of air pollution control equipment that would cause emissions of the relevant pollutant to increase within the past year.

- The specific information regarding each period of excess emissions and parameter monitoring exceedances.
- Records of the date and time that each deviation started and stopped.
- Records of the occurrence and duration of each malfunction of the boiler or process heater, or of the associated air pollution control and monitoring equipment.
- Records of actions taken during periods of malfunction to minimize emissions, including corrective actions to restore the malfunctioning boiler, air pollution control, or monitoring equipment to its normal or usual manner of operation (include description) and preventative actions adopted to prevent a reoccurrence.

7.2.1 Recordkeeping for CMS

Additionally, if the boiler or process heater is utilizing a CMS for compliance, you must keep the following records:

- All results of performance tests, CMS performance evaluations, and opacity and visibility emissions observations.
- Previous versions of the performance evaluation plan.
- Request for alternatives to relative accuracy test for CEMS.
- All CMS calibration checks.
- All adjustments and maintenance performed on CMS.
- All required CMS measurements.
- The date and time of any occurrence when the CMS was out-of-control.
- The date and time of each period your CMS was inoperative except for zero (low-level) and high-level checks.
- The date and time of any occurrence when your CMS was out-of-control.
- The specific identification of each period of excess emissions and parameter monitoring exceedances, including those that occur during start-ups, shut-downs, and malfunctions.
- The nature and cause of any malfunction.
- The corrective action taken or preventive measures adopted.
- The total process operating time during the reporting period.
- All procedures that are part of a quality control program developed and implemented for the CMS.

NOTE: For each start-up period, a facility must maintain specific records including the times that clean fuel combustion begins and ends; the time that PM controls are engaged; the hourly steam temperature, pressure, flow rate, etc...; and certain control device operating data.

7.3 Enhanced Recordkeeping Requirements When Complying with Definition 2 of Start-Up

Facilities electing to comply with “Definition 2” of “Start-up” in §63.7575 have enhanced recordkeeping requirements. For each start-up period, for units complying with Definition (2) of “start-up”, the following records must be maintained:

- Maintain records of the time that clean fuel combustion begins.
- The time when feeding fuels that are not clean fuels begins.
- The time when useful thermal energy is first supplied.
- The time when the PM controls are engaged.
- Records of the hourly steam temperature, hourly steam pressure, hourly steam flow, hourly flue gas temperature, and 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 during each start-up period to confirm that the control devices are engaged.

In addition, if compliance with the PM emission limit is demonstrated using a PM control device, the following records must be maintained:

- For a boiler or process heater with an ESP, record the number of fields in service, as well as each field’s secondary voltage and secondary current during each hour of start-up.
- For a boiler or process heater with a fabric filter, record the number of compartments in service, as well as the differential pressure across the baghouse during each hour of start-up.
- For a boiler or process heater with a wet scrubber needed for filterable PM control, record the scrubber’s liquid flow rate and the pressure drop during each hour of start-up.

7.4 Waiver of Recordkeeping or Reporting Requirements [§63.10(f)]

Recordkeeping or reporting requirements may be waived upon written application to the Administrator if, in the Administrator's judgment, the boiler or process heater is achieving the standard(s), or operating under an extension of compliance, or the facility has requested an extension of compliance and the Administrator is still considering that request. The facility remains subject to the requirements until a waiver of a recordkeeping or reporting requirement has been granted by the Administrator. The application shall include whatever information the facility considers useful to convince the Administrator that a waiver of recordkeeping or reporting is warranted. This includes any required compliance progress report, compliance status report, or CMS performance report, whichever is applicable.

A waiver of any recordkeeping or reporting requirement granted may be conditioned on other recordkeeping or reporting requirements deemed necessary by the Administrator. Approval of any waiver granted under this section will not abrogate the Administrator's authority or in any way prohibit the Administrator from later canceling the waiver. The cancellation will be made only after notice is given to the owner or operator of the boiler or process heater.

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8 NEW SOURCE PERFORMANCE STANDARDS

The purpose of this chapter is to provide a very general overview of the New Source Performance Standards (NSPS) as the standards pertain to boilers. The intent is to alert USAF personnel responsible for boilers that some boilers may be subject to Boiler MACT and/or NSPS.

The EPA promulgated NSPS to ensure new sources of air pollution pollute less than the older units they replace. Unlike Boiler MACT that regulates HAPs, NSPS focuses more on criteria pollutants such as Particulate Matter (PM), Nitrogen Dioxide (NO₂), and Sulfur Dioxide (SO₂). NSPS requirements for Industrial-Commercial-Institutional Boilers (steam generating units), capable of combusting over 10 MMBtu/hr of fuel, are found under 40 CFR Part 60 Subparts Db and Dc:

- Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units (Subpart Dc) - Affects Industrial-Commercial-Institutional steam generating units (boilers) that commenced construction, modification, or reconstruction after 9 June 1989, with a maximum design heat input capacity greater than or equal to 10 MMBtu/hr but less than or equal to 100 MMBtu/hr. These boilers may burn natural gas, gasoline, fuel oil, wood, coal, or alternative fuels.
- Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units (Subpart Db) - Affects Industrial-Commercial-Institutional steam generating units with a maximum design heat input capacity greater than 100 MMBtu/hr (that are not utility boilers) that commenced construction, modification, or reconstruction after 18 September 1978.

Each NSPS has emission limits (may require performance testing), notification, recordkeeping, and reporting requirements. Some of the Boiler MACT and NSPS requirements may overlap. If the boiler is subject to subpart Dc or Db, it is automatically subject to the NSPS General Provisions found in Subpart A of 40 CFR §60. The General Provisions contain some definitions and describe the performance testing, recordkeeping, reporting, and monitoring provisions that apply to every source subject to NSPS.

Natural gas and dual-fuel (gas and oil) boilers are predominately used at USAF facilities. Natural gas-fired boilers emit significantly lower levels of PM, NO_x, and SO_x than boilers fired with other fuels. Although the use of distillate or ULSD fuel oil results in somewhat higher emissions than natural gas, those fuels are significantly cleaner than other grades of oil or solid fuels. For this reason, gas-fired boilers do not have emission limits under Subpart DDDDD or NSPS. Most boilers fired on only natural gas and/or fuel oil meet the requirements of Subpart Dc by using ULSD (oil-fired boiler) and maintaining a detailed log of fuel usage.

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APPENDIX A: APPLICABILITY QUESTIONNAIRE FOR MAJOR SOURCE BOILERS

National Emission Standards for Hazardous Air Pollutants (NESHAP): Industrial, Commercial, and Institutional Boilers and Process Heaters at Major Sources 40 CFR 63, Subpart DDDDD (Subpart DDDDD)

This questionnaire is designed to assist with identifying whether a boiler or process heater is subject to Subpart DDDDD. An industrial, commercial, or institutional boiler or process heater that is located at, or is part of, a Major Source of Hazardous Air Pollutants (HAPs) is subject to Subpart DDDDD. Answer the questions in the order presented.

Is the unit a boiler or process heater?

- **Boiler** means an enclosed device using controlled flame combustion in which water is heated to recover thermal energy in the form of steam and/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.
- **Process Heater** is 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 (e.g., glycol or a mixture of glycol and water) 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.
 - Process heaters do NOT include units used for comfort heat or space heat or used for food preparation for on-site consumption.
 - Solid Waste Incineration Units (device combusting solid waste), Waste heat boilers/process heaters, and autoclaves are NOT boilers or process heaters.

Is the unit a boiler or process heater as defined above?

YES NO

(If **NO**, the unit is not subject to Subpart DDDDD **Stop here.**)

Is the boiler or process heaters located at a Major Source of HAPs?

- **Major source** means any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit considering controls, in the aggregate, 10 tons per year or more of any federally regulated HAP or 25 tons per year or more of any combination of HAPs.
- **Area source** means any stationary source of hazardous air pollutants that is not a major source.

Is the boiler or process heater located at a Major Source of HAPs?

YES NO

(If **NO**, the unit is not located at a Major Source of HAPs and is not subject to Subpart DDDDD. **Stop here, the boiler is likely subject to 40 CFR 63, Subpart JJJJJJ.**)

Is the boiler or process heater residential?

- **Residential boilers and process heaters as Defined in Subpart DDDDD** – Provides heat and/or hot water and/or as part of a residential combined heat and power system. This definition includes units located at an institutional facility (e.g., military base) or commercial/industrial facility used primarily to provide heat and/or hot water for:
 - A dwelling containing four or fewer families or a single unit residence dwelling that has since been converted or subdivided into condominiums or apartments. [§63.11237 and §63.11195(i)]

Is the unit a residential boiler or process heater as defined above? **YES** **NO**

(If **YES**, the unit is not subject to Subpart DDDDD. **Stop here.**)

Is the boiler otherwise excluded from Subpart DDDDD?

The following boilers are not subject to Subpart DDDDD (refer to the rule or this Guide for more detailed definitions if necessary):

- Hot water heaters < 120 gal capacity and hot water boilers not generating steam with a capacity < 1.6 MMBtu/hr fired by gas, oil, or biomass; and tankless on-demand hot water heaters.
- Temporary boilers burning gas or liquid fuel and capable of being carried or moved from one location to another (e.g., has wheels, handles, skids) and does not remain at one location for more than 12 consecutive months (NOT used more than three months annually for two years if located at a seasonal facility).
- Hazardous waste incinerators.
- Boilers and process heaters subject to another NESHAP (e.g., Electric Utility Steam Generating Unit).
- Control devices with > 50% of the gas stream coming from a controlled gas stream.
- Waste heat boilers/process heaters (heat recovery steam generators) recovering normally unused exhaust gas converting it to usable heat or steam.
- Research & development boilers and process heaters.
- Blast furnace gas-fired boilers/stoves/process heaters (receives > 90% of total annual gas from blast furnace gas).

Is the boiler listed as an excluded boiler? **YES** **NO**

(If **YES**, the boiler is not subject to Subpart DDDDD. **Stop here.**)

If the boiler or process heater is subject to Subpart DDDDD, compliance requirements (e.g., tune-up, emission limits) are dependent on factors such the date of construction or reconstruction, fuel type, and boiler size.

APPENDIX B: Emission Limits and Testing Methods

Emission Limits for New and Reconstructed Boilers and Process Heaters (Table 1, Subpart DDDDD)												
Fuel Class	Subcategory	Input Emission limits (lb/MMBtu of heat input unless otherwise noted)						Alternative output-based limits [lb/MMBtu of steam output or (lb per MWh) unless noted]				
		Hg	HCl	Filter. PM	TSM	CO	CO CEMS*	Hg	HCl	Filter. PM	TSM	CO
Coal	Pulverized	8.00E-07	2.20E-02	1.10E-03	2.30E-05	130 ^b	320 ^a	8.7E-07 (1.1E-05)	2.5E-02 (0.28)	1.1E-03 (1.4E-02)	2.7E-05 (2.9E-04)	0.11 (1.4) ^f
	Stoker					130 ^b	340 ^a					0.12 (1.4) ^f
	Fluidized Bed					130 ^b	230 ^a					0.11 (1.4) ^f
	Fluidized Bed w/int. heat exchanger					140 ^b	150 ^a					1.2E-01 (1.5) ^f
Biomass	Stokers/sloped grate/others (wet)			3.00E-02	2.60E-05	620 ^b	390 ^a			3.5E-02 (4.2E-01)	2.7E-05 (3.7E-04)	5.8E-01 (6.8) ^f
	Stokers/sloped grate/others (kilndried)			3.00E-02	4.00E-03	460 ^c	N/A			3.5E-02 (4.2E-01)	4.20E-03 (5.6E-02)	4.2E-01 (5.1)
	Fluidized Bed			9.80E-03	8.30E-05	230 ^b	310 ^a			1.2E-02 (0.14)	1.1E-04 (1.2E-03)	2.2E-01 (2.6) ^f
	Suspension Burners			3.00E-02	6.50E-03	2400 ^b	2000 ^d			3.1E-02 (4.2E-01)	6.6E-03 (9.1E-02)	1.9 (27) ^f
	Dutch Oven/Pile Burner			3.20E-03	3.90E-05	330 ^b	520 ^d			4.3E-03 (4.5E-02)	5.2E-05 (5.5E-04)	3.5E-01 (3.6) ^f
	Fuel Cell			2.00E-02	2.90E-05	910 ^c	N/A			3.0E-02 (2.8E-01)	5.1E-05 (4.1E-04)	1.1 (1.0E+0)
	Hybrid Suspension Grate			2.60E-02	4.40E-04	1100 ^b	900 ^a			3.3E-02 (3.7E-01)	5.5E-04 (6.2E-03)	1.4 (12) ^f
Liquid	Heavy	4.80E-07	4.40E-04	1.30E-02	7.50E-05	130 ^b	N/A	5.3E-07 (6.7E-06)	4.8E-04 (6.1E-03)	1.5E-02 (1.8E-01)	8.2E-05 (1.1E-03)	0.13 (1.4) ^f
	Light			1.10E-03	2.90E-05	130 ^c	N/A	5.3E-07 (6.7E-06)	4.8E-04 (6.1E-03)	1.2E-03 (1.6E-02)	3.2E-05 (4.0E-04)	0.13 (1.4)
	Non-continental			2.30E-02	8.60E-04	130 ^e	N/A	5.3E-07 (6.7E-06)	4.8E-04 (6.1E-03)	2.5E-02 (3.2E-01)	9.4E-04 (1.2E-02)	0.13 (1.4) ^f
Gas 2	Gas 2 (other)	7.90E-06	1.70E-03	6.70E-03	2.10E-04	130 ^c	N/A	1.4E-05 (8.3E-05)	2.90E-03 (1.8E-02)	1.2E-02 (7.0E-02)	3.5E-04 (2.2E-03)	0.16 (1.0)
^a ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average ^b ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average ^c ppm by volume on a dry basis corrected to 3 percent oxygen ^d ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average ^e ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test ^f 3-run average												

Emission Limits for Existing Boilers and Process Heaters (Table 2, Subpart DDDDD)												
Fuel Class	Subcategory	Input Emission limits (lb/MMBtu of heat input unless otherwise noted)						Alternative output-based limits [lb/MMBtu of steam output or (lb per MWh) unless noted]				
		Hg	HCl	Filter. PM	TSM	CO	CO CEMS*	Hg	HCl	Filter. PM	TSM	CO
Coal	Pulverized	5.7E-06	2.2E-02	4.0E-02	5.3E-05	130 ^b	320 ^a	6.4E-06 (7.3E-05)	2.5E-02 (0.27)	4.2E-02 (4.9E-01)	5.6E-05 (6.5E-04)	0.11 (1.4) ^f
	Stoker					160 ^b	340 ^a					0.14 (1.7) ^f
	Fluidized Bed					130 ^b	230 ^a					0.12 (1.4) ^f
	Fluidized Bed w/int. heat exchanger					140 ^b	150 ^a					1.3E-01 (1.5) ^f
Biomass	Stokers/sloped grate/others (wet)			3.7E-02	2.4E-04	1500 ^b	720 ^a			4.3E-02 (5.2E-01)	2.8E-04 (3.4E-04)	1.4 (17) ^f
	Stokers/sloped grate/others (kiln-dried)			3.2E-01	4.0E-03	460 ^c	N/A			3.7E-01 (4.5)	4.6E-03 (5.6E-02)	4.2E-01 (5.1)
	Fluidized Bed			1.1E-01	1.2E-03	470 ^b	310 ^a			1.4E-01 (1.6)	1.5E-03 (1.7E-02)	4.6E-01 (5.2) ^f
	Suspension Burners			5.1E-02	6.5E-03	2400 ^b	2000 ^d			5.2E-02 (7.1E-01)	6.6E-03 (9.1E-02)	1.9 (27) ^f
	Dutch Oven/Pile Burner			2.8E-01	2.0E-03	770 ^b	520 ^d			3.9E-01 (3.9)	2.8E-03 (2.8E-02)	8.4E-01 (8.4) ^f
	Fuel Cell			2.0E-02	5.8E-03	1100 ^c	N/A			5.5E-02 (2.8E-01)	1.6E-02 (8.1E-02)	2.4 (12)
	Hybrid Suspension Grate			4.4E-01	4.5E-04	3500 ^b	900 ^a			5.5E-01 (6.2)	5.7E-04 (6.3E-03)	3.5 (39) ^f
Liquid	Heavy	2.0E-06	1.1E-03	6.2E-02	2.0E-04	130 ^b	N/A	2.5E-06 (2.8E-05)	1.4E-03 (1.6E-02)	7.5E-02 (8.6E-01)	2.5E-04 (2.8E-03)	0.13 (1.4) ^f
	Light			7.9E-03	6.2E-05	130 ^c	N/A	2.5E-06 (2.8E-05)	1.4E-03 (1.6E-02)	9.6E-03 (1.1E-01)	7.5E-05 (8.6E-04)	0.13 (1.4)
	Non-continental			2.7E-01	8.6E-04	130 ^e	N/A	2.5E-06 (2.8E-05)	1.4E-03 (1.6E-02)	3.3E-01 (3.8)	1.1E-03 (1.2E-02)	0.13 (1.4) ^f
Gas 2	Gas 2 (other)	7.9E-06	1.7E-03	6.7E-03	2.1E-04	130 ^c	N/A	1.4E-05 (8.3E-05)	2.9E-03 (1.8E-02)	1.2E-02 (7.0E-02)	3.5E-04 (2.2E-03)	0.16 (1.0)
^a ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average						^b ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average						
^c ppm by volume on a dry basis corrected to 3 percent oxygen						^d ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average						
^e ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test						^f 3-run average						

*For the alternate CO CEMS emission limit (applies to both new and existing units with a CO CEMS emission limit), an alternative test method may be requested under §63.7, in order that compliance with the CO emissions limit be determined using as a diluent correction in place of oxygen at 3%. EPA Method 19 F-factors and EPA Method 19 Equations must be used to generate the appropriate CO₂ correction percentage for the fuel type burned in the unit, and must also take into account that the 3% oxygen correction is to be done on a dry basis. The alternative test method request must account for any CO₂ being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc.

Gas 2 Boiler and Process Heaters - Testing Methods Emissions must not exceed emission limits, except during start-up and shut-down, using the following specified sampling volume or test run duration:	
Pollutant	Method
Hydrogen Chloride (HCl)	For M26A, Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
Mercury (Hg)	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784b collect a minimum of 3 dscm.
Filterable Particulate Matter (PM) -OR- Total Selected Metals (TSM)	Collect a minimum of 3 dscm per run.
Carbon Monoxide (CO) - OR - CO Continuous Emissions Monitoring System	1 hr minimum sampling time.

Coal Boiler and Process Heaters - Testing Methods Emissions must not exceed emission limits, except during start-up and shut-down, using the following specified sampling volume or test run duration:	
Pollutant	Method
Hydrogen Chloride (HCl)	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
Mercury (Hg)	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784b collect a minimum of 4 dscm.
Filterable Particulate Matter (PM) -OR- Total Selected Metals (TSM)	Collect a minimum of 3 dscm per run.
Carbon Monoxide (CO) - OR - CO Continuous Emissions Monitoring System	1 hr minimum sampling time

Biomass/Bio-Based Solids Boiler and Process Heaters - Testing Methods							
Emissions must not exceed emission limits, except during start-up and shut-down, using the following specified sampling volume or test run duration:							
Pollutant	Stokers/sloped grate/others designed to burn wet biomass fuel	Stokers/sloped grate/others designed to burn kiln-dried biomass fuel	Suspension burners	Fuel cell	Fluidized bed	Dutch Ovens/Pile burners	Hybrid suspension grate
	Collect a minimum of 2 dscm per run.				Collect a minimum of 3 dscm per run.		
Hydrogen Chloride (HCl)	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.						
Mercury (Hg)	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784b collect a minimum of 4 dscm.						
Carbon Monoxide (CO) - OR - CO Continuous Emissions Monitoring System	1 hr minimum sampling time.						

Liquid Fuel Boiler and Process Heaters - Testing Methods Emissions must not exceed emission limits, except during start-up and shut-down, using the following specified sampling volume or test run duration:			
Pollutant...	Method...		
	Light Liquid Fuel	Heavy Liquid Fuel	Noncontinental
Filterable Particulate Matter (PM) -OR- Total Selected Metals (TSM)	Collect a minimum of 3 dscm per run	Collect a minimum of 1 dscm per run	Collect a minimum of 2 dscm per run
Carbon Monoxide (CO) - OR - CO Continuous Emissions Monitoring System	1 hr minimum sampling time.		
Mercury (Hg)	For M29, collect a minimum of 3 dscm per run; for M30A or M30B collect a minimum sample as specified in the method, for ASTM D6784b collect a minimum of 2 dscm.		
Hydrogen Chloride (HCl)	For M26A, collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.		

APPENDIX C: Emission Averaging for Existing Boilers and Process Heaters

(Compliance Tool for existing boilers and process heaters with emission limits using alternative output-based emission limits)

1. Emissions averaging is an alternative to meeting the emission limit requirements of §63.7500 for PM (or TSM), HCl, or Hg, on a boiler or process heater-specific basis. If there are more than one existing boiler or process heater in any subcategories located at the facility, compliance may be demonstrated by emissions averaging, if the averaged emissions are not more than 90 percent of the applicable emission limit, according to the procedures in §63.7522. Emissions averaging can NOT include new boilers or process heaters. [§63.7522(a)]
2. For a group of two or more existing boilers or process heaters in the same subcategory that each vent to a separate stack, the facility may average PM (or TSM), HCl, or Hg emissions among existing units to demonstrate compliance with the limits in Table 2 of Subpart DDDDD as specified in paragraph (b)(1) through (3) of §63.7522, as listed below, if the facility satisfies the requirements in paragraphs (c) through (g) of §63.7522. [§63.7522(b)]
 - a. The facility may average units using a CEMS or PM CPMS for demonstrating compliance. [§63.7522(b)(1)]
 - b. For Hg and HCl, averaging is allowed as follows:
 - i. May average among units in any of the solid fuel subcategories. [§63.7522(b)(2)(i)]
 - ii. May average among units in any of the liquid fuel subcategories. [§63.7522(b)(2)(ii)]
 - iii. May average among units in a subcategory of units designed to burn Gas 2 (other) fuels. [§63.7522(b)(2)(iii)]
 - iv. May NOT average across the units designed to burn liquid, units designed to burn solid fuel, and units designed to burn Gas 2 (other) subcategories. [§63.7522(b)(2)(iv)]
 - c. For PM (or TSM), averaging is only allowed between units within each of the following subcategories and the facility may not average across subcategories: Units designed to burn coal/solid fossil fuel. [§63.7522(b)(3)(i)]
 - i. Stokers/sloped grate/other units designed to burn kiln dried biomass/bio-based solids. [§63.7522(b)(3)(ii)]
 - ii. Stokers/sloped grate/other units designed to burn wet biomass/bio-based solids. [§63.7522(b)(3)(iii)]
 - iii. Fluidized bed units designed to burn biomass/bio-based solid. [§63.7522(b)(3)(iv)]
 - iv. Suspension burners designed to burn biomass/bio-based solid. [§63.7522(b)(3)(v)]
 - v. Dutch ovens/pile burners designed to burn biomass/bio-based solid. [§63.7522(b)(3)(vi)]

- vi. Fuel Cells designed to burn biomass/bio-based solid. [§63.7522(b)(3)(vii)]
 - vii. Hybrid suspension/grate burners designed to burn wet biomass/bio-based solid. [§63.7522(b)(3)(viii)]
 - viii. Units designed to burn heavy liquid fuel. [§63.7522(b)(3)(ix)]
 - ix. Units designed to burn light liquid fuel. [§63.7522(b)(3)(x)]
 - x. Units designed to burn Gas 2 (other) gases. [§63.7522(b)(3)(xii)]
3. For each existing boiler or process heater in the averaging group, the emission rate achieved during the initial compliance test for the HAP being averaged must not exceed the emission level that was being achieved on January 31, 2013 or the control technology employed during the initial compliance test must not be less effective for the HAP being averaged than the control technology employed on January 31, 2013. [§63.7522(c)]
 4. The averaged emissions rate from the existing boilers and process heaters participating in the emissions averaging option must not exceed 90 percent of the limits in Table 2 of Subpart DDDDD at all times the affected units are operating following the compliance date specified in §63.7495, i.e., January 31, 2016 or as otherwise specified in §63.6(i). [§63.7522(d)]
 5. The facility must demonstrate initial compliance according to paragraph (e)(1) or (2) of §63.7522, as listed below, using the maximum rated heat input capacity or maximum steam generation capacity of each unit and the results of the initial performance tests or fuel analysis. [§63.7522(e)]
 - a. The facility must use Equation 1a or 1b or 1c of §63.7522 to demonstrate that the PM (or TSM), HCl, or Hg emissions from all existing units participating in the emissions averaging option for that pollutant do not exceed the emission limits in Table 2 of Subpart DDDDD. Use Equation 1a if the facility is complying with the emission limits on a heat input basis, use Equation 1b if the facility is complying with the emission limits on a steam generation (output) basis, and use Equation 1c if the facility is complying with the emission limits on an electric generation (output) basis. [§63.7522(e)(1)]

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^n (Er \times Hm) \div \sum_{i=1}^n Hm \quad (Equation 1a)$$

Where:

AveWeightedEmissions = Average weighted emissions for PM (or TSM), HCl, or Hg, in units of lb/MMBtu of heat input.

Er = Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or Hg from unit, i, in units of lb/MMBtu of heat input. Determine the emission

rate for PM (or TSM), HCl, or Hg by performance testing according to Table 5 to Subpart DDDDD, or by fuel analysis for HCl or Hg or TSM using the applicable equation in §63.7530(c).

Hm = Maximum rated heat input capacity of unit, i, in units of MMBtu/hr.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^n (Er \times So) \div \sum_{i=1}^n So \quad (Equation 1b)$$

Where:

AveWeightedEmissions = Average weighted emissions for PM (or TSM), HCl, or Hg, in units of lb/MMBtu of steam output.

Er = Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or Hg from unit, i, in units of lb/MMBtu of steam output. Determine the emission rate for PM (or TSM), HCl, or Hg by performance testing according to Table 5 to Subpart DDDDD, or by fuel analysis for HCl or Hg or TSM using the applicable equation in §63.7530(c). If the facility is taking credit for energy conservation measures from a unit according to §63.7533, use the adjusted emission level for that unit, E_{adj} , determined according to §63.7533, for that unit.

So = Maximum steam output capacity of unit, i, in units of MMBtu/hr, as defined in §63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^n (Er \times Eo) \div \sum_{i=1}^n Eo \quad (Equation 1c)$$

Where:

AveWeightedEmissions = Average weighted emissions for PM (or TSM), HCl, or Hg, in units of pounds per megawatt hour.

Er = Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or Hg from unit, i, in units of pounds per megawatt hour. Determine the emission rate for PM (or TSM), HCl, or Hg by performance testing according to Table 5 of Subpart DDDDD, or by fuel analysis for HCl or Hg or TSM using the applicable equation in §63.7530(c). If the facility is taking credit for energy conservation measures from a unit according to §63.7533, use the adjusted emission level for that unit, E_{adj} , determined according to §63.7533, for that unit.

E_o = Maximum electric generating output capacity of unit, i , in units of megawatt hour, as defined in §63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = required discount factor.

- b. If the facility is not capable of determining the maximum rated heat input capacity of one or more boilers that generate steam, the facility may use Equation 2 of §63.7522 as an alternative to using Equation 1a of §63.7522 to demonstrate that the PM (or TSM), HCl, or Hg emissions from all existing units participating in the emissions averaging option do not exceed the emission limits for that pollutant in Table 2 of Subpart DDDDD that are in lb/MMBtu of heat input. [§63.7522(e)(2)]

AveWeightedEmissions

$$= 1.1 \times \sum_{i=1}^n (E_r \times S_m \times C_f i) \div \sum_{i=1}^n (S_m \times C_f i) \quad (\text{Equation 2})$$

Where:

AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or Hg, in units of lb/MMBtu of heat input.

E_r = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or Hg from unit, i , in units of lb/MMBtu of heat input. Determine the emission rate for PM (or TSM), HCl, or Hg by performance testing according to Table 5 to Subpart DDDDD, or by fuel analysis for HCl or Hg or TSM using the applicable equation in §63.7530(c).

S_m = Maximum steam generation capacity by unit, i , in units of pounds per hour.

$C_f i$ = Conversion factor, calculated from the most recent compliance test, in units of million Btu of heat input per pounds of steam generated for unit, i .

1.1 = Required discount factor.

6. After the initial compliance demonstration described in paragraph (e) of §63.7522, the facility must demonstrate compliance on a monthly basis determined at the end of every month (12 times per year) according to paragraphs (f)(1) through (3) of §63.7522, as listed below. The first monthly period begins on the compliance date specified in §63.7495, i.e., 31 January 2016 or as otherwise specified in §63.6(i). If the affected source elects to collect monthly data for up to the 11 months preceding the first monthly period, these additional data points can be used to compute the 12-month rolling average in paragraph (f)(3) of §63.7522, as listed below. [§63.7522(f)]

- a. For each calendar month, the facility must use Equation 3a or 3b or 3c of §63.7522 to calculate the average weighted emission rate for that month. Use Equation 3a and the actual heat input for the month for each existing unit participating in the emissions averaging option if the facility is complying with emission limits on a heat input basis. Use Equation 3b and the actual steam generation for the month if the facility is complying with the emission limits on a steam generation (output) basis. Use Equation 3c and the actual steam generation for the month if the facility is complying with the emission limits on an electrical generation (output) basis. [§63.7522(f)(1)]

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^n (Er \times Hb) \div \sum_{i=1}^n Hb \quad (Equation\ 3a)$$

Where:

AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or Hg, in units of lb/MMBtu of heat input, for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or Hg from unit, i, in units of lb/MMBtu of heat input. Determine the emission rate for PM (or TSM), HCl, or Hg by performance testing according to Table 5 to Subpart DDDDD, or by fuel analysis for HCl or Hg or TSM according to Table 6 to Subpart DDDDD.

Hb = The heat input for that calendar month to unit, i, in units of MMBtu.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^n (Er \times So) \div \sum_{i=1}^n So \quad (Equation\ 3b)$$

Where:

AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or Hg, in units of lb/MMBtu of steam output, for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or Hg from unit, i, in units of lb/MMBtu of steam output. Determine the emission rate for PM (or TSM), HCl, or Hg by performance testing according to Table 5 to Subpart DDDDD, or by fuel analysis for HCl or Hg or TSM according to Table 6 to Subpart DDDDD. If the facility is taking credit for energy conservation measures from a unit according to §63.7533, use the adjusted emission level for that unit, E_{adj} , determined according to §63.7533, for that unit.

So = The steam output for that calendar month from unit, i, in units of MMBtu, as defined in §63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^n (Er \times Eo) \div \sum_{i=1}^n Eo \quad (Equation\ 3c)$$

Where:

AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or Hg, in units of pounds per megawatt hour, for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or Hg from unit, i, in units of pounds per megawatt hour. Determine the emission rate for PM (or TSM), HCl, or Hg by performance testing according to Table 5 §Part 63, Subpart DDDDD, or by fuel analysis for HCl or Hg or TSM according to Table 6 to Subpart DDDDD. If the facility is taking credit for energy conservation measures from a unit according to §63.7533, use the adjusted emission level for that unit, E_{adj}, determined according to §63.7533, for that unit.

Eo = The electric generating output for that calendar month from unit, i, in units of megawatt hour, as defined in §63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

- c. If the facility is not capable of monitoring heat input, the facility may use Equation 4 of §63.7522 as an alternative to using Equation 3a of §63.7522 to calculate the average weighted emission rate using the actual steam generation from the boilers participating in the emissions averaging option. [§63.7522(f)(2)]

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^n (Er \times Sa \times Cfi) \div \sum_{i=1}^n (Sa \times Cfi) \quad (Equation\ 4)$$

Where:

AveWeightedEmissions = average weighted emission level for PM (or TSM), HCl, or Hg, in units of lb/MMBtu of heat input for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration of PM (or TSM), HCl, or Hg from unit, i, in units of lbs/MMBtu of heat input. Determine the emission rate for PM (or TSM), HCl, or Hg by performance testing according to Table 5

to Subpart DDDDD, or by fuel analysis for HCl or Hg or TSM according to Table 6 to Subpart DDDDD.

Sa = Actual steam generation for that calendar month by boiler, i, in units of pounds.

Cfi = Conversion factor, as calculated during the most recent compliance test, in units of MMBtu of heat input per pounds of steam generated for boiler, i.

1.1 = Required discount factor.

- d. Until 12 monthly weighted average emission rates have been accumulated, calculate and report only the average weighted emission rate determined under paragraph (f)(1) or (2) of §63.7522 for each calendar month. After 12 monthly weighted average emission rates have been accumulated, for each subsequent calendar month, use Equation 5 of §63.7522 to calculate the 12-month rolling average of the monthly weighted average emission rates for the current calendar month and the previous 11 calendar months. [§63.7522(f)(3)]

$$E_{avg} = \sum_{i=1}^n ER_i \div 12 \quad (\text{Equation 5})$$

Where:

Eavg = 12-month rolling average emission rate, (lbs/MMBtu heat input)

ERi = Monthly weighted average, for calendar month “i” (lbs/MMBtu heat input), as calculated by paragraph (f)(1) or (2) of §63.7522.

7. The facility must develop, and submit upon request to the applicable Administrator for review and approval, an implementation plan for emission averaging according to the procedures and requirements in paragraphs (g)(1) through (4) of §63.7522, as listed below. [§63.7522(g)]
- a. The facility must submit the implementation plan no later than 180 days before the date that the facility intends to demonstrate compliance using the emission averaging option. [§63.7522(g)(1)]
- b. The facility must include the information contained in paragraphs (g)(2)(i) through (vii) of §63.7522 in the implementation plan for all emission sources included in an emissions average:
- i. The identification of all existing boilers and process heaters in the averaging group, including for each either the applicable HAP emission level or the control technology installed as of 31 January 2013 and the date on which the facility is requesting emission averaging to commence. [§63.7522(g)(2)(i)]

- ii. The process parameter (heat input or steam generated) that will be monitored for each averaging group. [§63.7522(g)(2)(ii)]
 - iii. The specific control technology or pollution prevention measure to be used for each emission boiler or process heater in the averaging group and the date of its installation or application. If the pollution prevention measure reduces or eliminates emissions from multiple boilers or process heaters, the owner or operator must identify each boiler or process heater. [§63.7522(g)(2)(iii)]
 - iv. The test plan for the measurement of PM (or TSM), HCl, or Hg emissions in accordance with the requirements in §63.7520 [§63.7522(g)(2)(iv)].
 - v. The operating parameters to be monitored for each control system or device consistent with §63.7500 and Table 4 to Subpart DDDDD, and a description of how the operating limits will be determined. [§63.7522(g)(2)(v)]
 - vi. If the facility requests to monitor an alternative operating parameter pursuant to §63.7525, the facility must also include:
 - (1). A description of the parameter(s) to be monitored and an explanation of the criteria used to select the parameter(s). [§63.7522(g)(2)(vi)(A)]
 - (2). A description of the methods and procedures that will be used to demonstrate that the parameter indicates proper operation of the control device; the frequency and content of monitoring, reporting, and recordkeeping requirements; and a demonstration, to the satisfaction of the Administrator, that the proposed monitoring frequency is sufficient to represent control device operating conditions. [§63.7522(g)(2)(vi)(B)]
 - vii. A demonstration that compliance with each of the applicable emission limit(s) will be achieved under representative operating load conditions. Following each compliance demonstration and until the next compliance demonstration, the facility must comply with the operating limit for operating load conditions specified in Table 4 to Subpart DDDDD. [§63.7522(g)(2)(vii)]
- c. The Administrator shall review and approve or disapprove the plan according to the following criteria:
- i. Whether the content of the plan includes all of the information specified in paragraph (g)(2) of §63.7522. [§63.7522(g)(3)(i)]
 - ii. Whether the plan presents sufficient information to determine that compliance will be achieved and maintained. [§63.7522(g)(3)(ii)]

- d. The applicable Administrator shall not approve an emission averaging implementation plan containing any of the following provisions:
 - i. Any averaging between emissions of differing pollutants or between differing sources. [§63.7522(g)(4)(i)]
 - ii. The inclusion of any emission source other than an existing unit in the same subcategories. [§63.7522(g)(4)(ii)]
8. For a group of two or more existing affected units, each of which vents through a single common stack, PM (or TSM), HCl, or Hg emissions may be averaged to demonstrate compliance with the limits for that pollutant in Table 2 of Subpart DDDDD if the facility satisfies the requirements in paragraph (i) or (j) of §63.7522, respectively [§63.7522(h)].
9. For a group of two or more existing units in the same subcategories, each of which vents through a common emissions control system to a common stack, that does not receive emissions from units in other subcategories or categories, the facility may treat such averaging group as a single existing unit for purposes of Subpart DDDDD and comply with the requirements of Subpart DDDDD as if the group were a single unit [§63.7522(i)].
10. For all other groups of units subject to the common stack requirements of paragraph (h) of §63.7522, including situations where the exhaust of affected units are each individually controlled and then sent to a common stack, the owner or operator may elect to:

- a. Conduct performance tests according to procedures specified in §63.7520 in the common stack if affected units from other subcategories vent to the common stack. The emission limits that the group must comply with are determined by the use of Equation 6 of [§63.7522(j)(1)]:

$$En = \sum_{i=1}^n (ELi \times Hi) \div \sum_{i=1}^n Hi \quad (\text{Equation 6})$$

Where:

En = HAP emission limit, lbs/MMBtu, parts per million (ppm), or nanograms per dry standard cubic meter (ng/dscm).

ELi = Appropriate emission limit from Table 2 of Subpart DDDDD for unit i, in units of lb/MMBtu, ppm or ng/dscm.

Hi = Heat input from unit i, MMBtu.

- b. Conduct performance tests according to procedures specified in §63.7520 in the common stack. If affected units and non-affected units vent to the common stack, the non-affected units must be shut down or vented to a different stack during the performance test unless

- the facility elects to demonstrate compliance with the non-affected units venting to the stack. [§63.7522(j)(2)]
- c. Meet the applicable operating limit specified in §63.7540 and Table 8 of Subpart DDDDD for each emissions control system (except that, if each unit venting to the common stack has an applicable opacity operating limit, then a single continuous opacity monitoring system may be located in the common stack instead of in each duct to the common stack). [§63.7522(j)(3)]
11. The common stack of a group of two or more existing boilers or process heaters in the same subcategories subject to paragraph (h) of §63.7522, may be treated as a separate stack for purposes of paragraph (b) of §63.7522, and included in an emissions averaging group subject to paragraph (b) of §63.7522. [§63.7522(k)]
12. Following the compliance date, compliance with Subpart DDDDD must be demonstrated on a continuous basis by meeting the requirements of paragraphs (a)(1) through (5) of §63.7541, as listed below.
- a. For each calendar month, demonstrate compliance with the average weighted emissions limit for the existing units participating in the emissions averaging option as determined in §63.7522(f) and (g). [§63.7541(a)(1)]
- b. The applicable opacity limit must be maintained according to paragraphs (a)(2)(i) and (ii) of §63.7541, as listed below. [§63.7541(a)(2)]
- i. For each existing unit participating in the emissions averaging option that is equipped with a dry control system and not vented to a common stack, maintain opacity at or below the applicable limit. [§63.7541(a)(2)(i)]
- ii. For each group of units participating in the emissions averaging option where each unit in the group is equipped with a dry control system and vented to a common stack that does not receive emissions from non-affected units, maintain opacity at or below the applicable limit at the common stack. [§63.7541(a)(2)(ii)]
- c. For each existing unit participating in the emissions averaging option that is equipped with a wet scrubber, maintain the 30-day rolling average parameter values at or above the operating limits established during the most recent performance test. [§63.7541(a)(3)]
- d. For each existing unit participating in the emissions averaging option that has an approved alternative operating parameter, maintain the 30-day rolling average parameter values consistent with the approved monitoring plan. [§63.7541(a)(4)]

- e. For each existing unit participating in the emissions averaging option venting to a common stack configuration containing affected units from other subcategories, maintain the appropriate operating limit for each unit as specified in Table 4 of Subpart DDDDD that applies. [§63.7541(a)(5)]
13. Any instance of failure to comply with the continuous monitoring requirements in paragraphs (a)(1) through (5) of §63.7541 is a deviation. [§63.7541(b)]

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APPENDIX D: Energy/Efficiency Credit Procedures

(Compliance Method for existing boilers and process heaters with emission limits using alternative output-based emission limits)

1. If the facility elects to comply with the alternative equivalent output-based emission limits, instead of the heat input-based limits listed in Table 2 of Subpart DDDDD, and the facility wants to take credit for implementing energy conservation measures identified in an energy assessment, the facility may demonstrate compliance using efficiency credits according to the procedures in §63.7533.
 - This compliance option may be used for an existing affected boiler for demonstrating initial compliance and for demonstrating monthly compliance according to §63.7522(e)(f).
 - Facilities electing this compliance option must establish an emissions benchmark, calculate and document the efficiency credits, develop an Implementation Plan, comply with the general reporting requirements, and apply the efficiency credit according to the procedures in paragraphs (b) through (f) of §63.7533.
2. For each existing affected boiler or process heater, establish a benchmark from which emission reduction credits may be generated by determining the actual annual fuel heat input to the affected boiler before initiation of an energy conservation activity to reduce energy demand according to paragraphs (b)(1) through (4) of §63.7533, as listed below. The benchmark shall be expressed in trillion Btu per year heat input.
 - The benchmark from which efficiency credits may be generated shall be determined by using the most representative, accurate, and reliable process available for the source. The benchmark shall be established for a one-year period before the date that an energy demand reduction occurs, unless it can be demonstrated that a different time period is more representative of historical operations.
 - Determine the starting point from which to measure progress. Inventory all fuel purchased and generated on-site (off-gases, residues) in physical units (MMBtu, million cubic feet, etc.).
 - Document all uses of energy from the affected boiler. Use the most recent data available.
 - Collect non-energy related facility and operational data to normalize, if necessary, the benchmark to current operations, such as building size, operating hours, etc. If possible, use actual data that are current and timely rather than estimated data.

[§63.7533(b)(1-4)]

3. Efficiency credits can be generated if the energy conservation measures were implemented after 1 January 2008 and if sufficient information is available to determine the appropriate value of credits. The following emission points cannot be used to generate efficiency credits:
 - Energy conservation measures implemented on or before 1 January 2008, unless the level of energy demand reduction is increased after 1 January 2008, in which case credit will be allowed only for change in demand reduction achieved after 1 January 2008.
 - Efficiency credits on shut-down boilers. Boilers that are shut down cannot be used to generate credits unless the facility provides documentation linking the permanent shut-down to energy conservation measures identified in the energy assessment. In this case, the bench established for the affected boiler to which the credits from the shut-down will be applied must be revised to include the benchmark established for the shut-down boiler.
[§63.7533(c)(1)(i-ii)]
4. For all points included in calculating emissions credits, the owner or operator shall calculate annual credits for all energy demand points. Energy conservation measures that meet the criteria of paragraph (c)(1) of §63.7533 shall not be included, except as specified in §63.7533 (c)(1)(i).
- c. Credits are generated by the difference between the benchmark that is established for each affected boiler, and the actual energy demand reductions from energy conservation measures implemented after 1 January 2008. Credits shall be calculated using Equation 19 of §63.7533, as listed below. [§63.7533(c)(3)]

The overall equation for calculating credits is [§63.7533(c)(3)(i)]:

$$ECredits = \left(\sum_{i=1}^N EIS_{iactual} \right) \div EI_{baseline} \quad Eq. 19$$

Where:

ECredits = Energy Input Savings for all energy conservation measures implemented for an affected boiler, expressed as a decimal fraction of the baseline energy input.

EIS_{iactual} = Energy Input Savings for each energy conservation measure, i, implemented for an affected unit, MMBtu/yr.

EI_{baseline} = Energy Input baseline for the affected unit, MMBtu/yr.

n = Number of energy conservation measures included in the efficiency credit for the affected boiler.

5. An Implementation Plan must be developed, and submitted upon request by the Administrator, containing all of the information required in this paragraph for all boilers and process heaters to be included in an efficiency credit option. If requested, the facility must submit the implementation plan for efficiency credits to the Administrator for review and approval no later than 180 days before the date on which the facility intends to demonstrate compliance using the efficiency credit option.
 - The Implementation Plan shall identify all existing affected boilers to be included in applying the efficiency credits.
 - The Implementation Plan shall include a description of the energy conservation measures implemented and the energy savings generated from each measure and an explanation of the criteria used for determining that savings.
 - The emissions rate as calculated using Equation 20 of §63.7533 from each existing boiler participating in the efficiency credit option must be in compliance with the limits in Table 2 of Subpart DDDDD at all times the affected unit is subject to emission limits, following the compliance date specified in §63.7495 (31 January 2016 for existing units), or as otherwise specified in §63.6(i).
 - The facility must use Equation 20 of §63.7533, as listed below, to demonstrate initial compliance by demonstrating that the emissions from the affected boiler participating in the efficiency credit compliance approach do not exceed the emission limits in Table 2 of Subpart DDDDD.

$$E_{adj} = E_m \times (1 - ECredits) \quad \text{Equation 20}$$

Where: E_{adj} = Emission level adjusted by applying the efficiency credits earned, lbs/MMBtu steam output [or lb per MWh] for the affected boiler.

E_m = Emissions measured during the performance test, lbs/MM Btu steam output (or lb per MWh) for the affected boiler.

ECredits = Efficiency credits from Equation 19 for the affected boiler.

[§63.7533(d-f)]

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APPENDIX E: Performance Testing

(Applies to most boilers and process heaters with emission limits)

If compliance is demonstrated through performance testing, the facility must establish each site-specific operating limit in Table 4 of Subpart DDDDD in accordance to the requirements in §63.7520, Table 7 of Subpart DDDDD, and paragraph (b)(4) of §63.7530, as applicable.

Note: If performance testing is used to demonstrate compliance with hydrogen chloride (HCl), mercury (Hg), or Total Selected Metals (TSM) emission limits, when establishing the maximum pollutant input levels, the heat input fractions used in Equations 7 through 9 should correspond to the fuel mixture that has the highest pollutant concentration during the initial compliance test. Furthermore, for demonstrating continuous compliance with these pollutant input levels, the heat input fractions should be based on the actual fractions of fuel burned during the month.

If a facility is subject to a carbon monoxide (CO) emission limit and chooses the continuous emissions monitoring systems (CEMS) alternative compliance option, then the oxygen level of the required oxygen trim system must be set to the concentration measured during the most recent tune-up to optimize CO to manufacturer's specifications.

Fuel Analysis Must be Conducted in Conjunction with the Performance Testing

1. The fuel analyses must be conducted according to §63.7521 and maximum fuel pollutant input levels established according to paragraphs (b)(1) through (3) of §63.7530, as applicable, and as specified in §63.7510(a)(2). Note §63.7510(a)(2), exempts certain fuels from fuel analysis, see the instructions regarding fuel analysis for further information on those fuels.
 - a. The maximum chlorine fuel input (C_{input}) must be determined during the initial fuel analysis according to the procedures in paragraphs (b)(1)(i) through (iii) of §63.7530.
 - i. The fuel type or fuel mixture that has the highest content of chlorine must be determined for each boiler or process heater. [§63.7530(b)(1)(i)]
 - ii. During the fuel analysis for HCl, the fraction of the total heat input for each fuel type burned (Q_i) based on the fuel mixture that has the highest content of chlorine, and the average chlorine concentration of each fuel type burned must be determined (C_i). [§63.7530(b)(1)(ii)]
 - iii. The maximum chlorine input level must be determined using Equation 7 of [§63.7530(b)(1)(iii)]:

$$C_{input} = \sum_{i=1}^n (C_i \times Q_i) \quad (\text{Equation 7})$$

Where:

C_{input} = Maximum amount of chlorine entering the boiler or process heater through fuels burned in units of pounds per million Btu (lbs/MMBtu).

C_i = Arithmetic average concentration of chlorine in fuel type, i , analyzed according to §63.7521 (Fuel Analysis Requirements), in units of lbs/MMBtu.

Q_i = Fraction of total heat input from fuel type, i , based on the fuel mixture that has the highest content of chlorine during the initial compliance test. If multiple fuel types are not burned during the performance testing, it is not necessary to determine the value of this term. Insert a value of “1” for Q_i . For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

n = Number of different fuel types burned in the boiler or process heater for the mixture that has the highest content of chlorine.

- b. The maximum mercury fuel input level (Mercuryinput) must be determined during the initial fuel analysis using the procedures in paragraphs (b)(2)(i) through (iii) of §63.7530, as listed below.
 - i. The fuel type or fuel mixture that has the highest content of Hg must be determined for each boiler or process heater. [§63.7530(b)(2)(i)]
 - ii. During the compliance demonstration for Hg, the fraction of total heat input for each fuel burned (Q_i) based on the fuel mixture that has the highest content of Hg, and the average Hg concentration of each fuel type burned must be determined (HG_i). [§63.7530(b)(2)(ii)]
 - iii. The facility must establish a maximum mercury input level using Equation 8 of [§63.7530(b)(2)(iii)]:

$$\text{Mercuryinput} = \sum_{i=1}^n (HG_i \times Q_i) \quad (\text{Equation 8})$$

Where:

Mercuryinput = Maximum amount of mercury entering the boiler or process heater through fuels burned in units of lbs/MMBtu.

HG_i = Arithmetic average concentration of Hg in fuel type, i , analyzed according to §63.7521 (Fuel Analysis Requirements), in units of lbs/MMBtu.

Q_i = Fraction of total heat input from fuel type, i , based on the fuel mixture that has the highest content of chlorine during the initial compliance test. If multiple fuel types are not burned during the performance testing, it is not necessary to determine the value of this term. Insert a value of “1” for Q_i . For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

n = Number of different fuel types burned in the boiler or process heater for the mixture that has the highest content of Hg.

- b. If the option to comply with the alternative TSM limit is elected, the maximum TSM fuel input (TSMinput) for solid or liquid fuels must be established during the initial fuel analysis according to the procedures in paragraphs (b)(3)(i) through (iii) of §63.7530.
 - i. The facility must determine the fuel type or fuel mixture that the facility could burn in the boiler or process heater that has the highest content of TSM. [§63.7530(b)(3)(i)]
 - ii. During the fuel analysis for TSM, the facility must determine the fraction of the total heat input for each fuel type burned (Qi) based on the fuel mixture that has the highest content of TSM, and the average TSM concentration of each fuel type burned (TSMi). [§63.7530(b)(3)(ii)]
 - iii. The facility must establish a maximum TSM input level using Equation 9 of [§63.7530(b)(3)(iii)]:

$$TSM_{input} = \sum_{i=1}^n (TSM_i \times Q_i) \quad (Equation\ 9)$$

Where:

TSMinput = Maximum amount of TSM entering the boiler or process heater through fuels burned in units of lbs/MMBtu.

TSMi = Arithmetic average concentration of TSM in fuel type, i, analyzed according to §63.7521 (Fuel Analysis Requirements), in units of lbs/MMBtu.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of chlorine during the initial compliance test. If multiple fuel types are not burned during the performance testing, it is not necessary to determine the value of this term. Insert a value of “1” for Qi. For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

n = Number of different fuel types burned in the boiler or process heater for the mixture that has the highest content of TSM.

Operating Limits Must be Established During Performance Testing

The operating limit parameters must be established according to paragraphs (b)(4)(i) through (ix) of §63.7530.

There is no requirement to establish and comply with the operating parameter limits when the facility is using a CEMS to monitor and demonstrate compliance with the applicable emission limit for that control device parameter. [§63.7530(b)(4)]

1. For a wet acid gas scrubber, the minimum scrubber effluent pH and liquid flow rate as defined in §63.7575, must be established as the operating limits during the performance test during which the facility demonstrates compliance with the applicable limit.

- a. If the boiler or process heater uses a wet scrubber and separate performance tests for HCl and Hg emissions are conducted, one set of minimum scrubber effluent pH, liquid flow rate, and pressure drop operating limits must be established. The minimum scrubber effluent pH operating limit must be established during the HCl performance test. If multiple performance tests are conducted, the minimum liquid flow rate operating limit must be set at the higher of the minimum values established during the performance tests. [§63.7530(b)(4)(i)]
2. For any particulate control device (e.g., ESP, particulate wet scrubber, fabric filter) for which the facility uses a Particulate Matter Continuous Monitoring System (PM CPMS), the facility must establish the PM CPMS operating limit and determine compliance with the limit according to paragraphs (b)(4)(ii)(A) through (F) of §63.7530. [§63.7530(b)(4)(ii)]
 - a. Determine the operating limit as the average PM CPMS output value recorded during the most recent performance test run demonstrating compliance with the filterable PM emission limit or at the PM CPMS output value corresponding to 75 percent of the emission limit if the PM performance test demonstrates compliance below 75 percent of the emission limit. The facility must verify an existing or establish a new operating limit after each repeated performance test. The facility must repeat the performance test annually and reassess and adjust the site-specific operating limit in accordance with the results of the performance test. [§63.7530(b)(4)(ii)(A)]
 - i. The PM CPMS must provide a 4-20 milliamp output and the establishment of its relationship to manual reference method measurements must be determined in units of milliamperes. [§63.7530(b)(4)(ii)(A)(1)]
 - ii. The PM CPMS operating range must be capable of reading PM concentrations from zero to a level equivalent to at least two times the allowable emission limit. If the PM CPMS is an auto-ranging instrument capable of multiple scales, the primary range of the instrument must be capable of reading PM concentration from zero to a level equivalent to two times the allowable emission limit. [§63.7530(b)(4)(ii)(A)(2)]
 - iii. During the initial performance test or any such subsequent performance test that demonstrates compliance with the PM limit, record and average all milliamp output values from the PM CPMS for the periods corresponding to the compliance test runs (e.g., average all the PM CPMS output values for three corresponding 2-hour Method 5 test runs). [§63.7530(b)(4)(ii)(A)(3)]
 - b. If the average of the three PM performance test runs are below 75 percent of the PM emission limit, the facility must calculate an operating limit by establishing a relationship of PM CPMS signal to PM concentration using the PM CPMS instrument zero, the average PM CPMS values corresponding to the three compliance test runs, and the average PM concentration from the Method 5 or performance test with the procedures in

paragraphs (b)(4)(ii)(B)(1) through (4) of §63.7530. Determine the instrument zero output with one of the following procedures:

- i. Zero-point data for in-situ instruments should be obtained by removing the instrument from the stack and monitoring ambient air on a test bench.
[§63.7530(b)(4)(ii)(B)(1)(i)]
 - ii. Zero-point data for extractive instruments should be obtained by removing the extractive probe from the stack and drawing in clean ambient air.
[§63.7530(b)(4)(ii)(B)(1)(ii)]
 - iii. The zero point may also be established by performing manual reference method measurements when the flue gas is free of PM emissions or contains very low PM concentrations (e.g., when your process is not operating, but the fans are operating or the source is combusting only natural gas) and plotting these with the compliance data to find the zero intercept.
[§63.7530(b)(4)(ii)(B)(1)(iii)]
 - iv. If none of the steps in paragraphs (b)(4)(ii)(B)(1)(i) through (iii) of §63.7530 are possible, the facility must use a zero output value provided by the manufacturer. [§63.7530(b)(4)(ii)(B)(1)(iv)]
- c. Determine the PM CPMS instrument average in milliamps, and the average of the corresponding three PM compliance test runs, using Equation 10
[§63.7530(b)(4)(ii)(B)(2)]:

$$\bar{X} = \frac{1}{n} \sum_{i=1}^n X_i \quad \bar{Y} = \frac{1}{n} \sum_{i=1}^n Y_i \quad (\text{Equation 10})$$

Where:

X_1 = the PM CPMS data points for the three runs constituting the performance test,

Y_1 = the PM concentration value for the three runs constituting the performance test, and

n = the number of data points.

- d. With the instrument zero expressed in milliamps, the three run average PM CPMS milliamp value, and the three run average PM concentration from the three compliance tests, determine a relationship of lbs/MMBtu per milliamp with Equation 11
[§63.7530(b)(4)(ii)(B)(3)]:

$$R = \frac{Y_1}{(X_1 - z)} \quad (\text{Equation 11})$$

Where:

R = the relative lbs/MMBtu per milliamp for the PM CPMS,

Y₁ = the three run average lbs/MMBtu PM concentration,

X₁ = the three run average milliamp output from the PM CPMS, and

z = the milliamp equivalent of the instrument zero determined from (B)(i).

- e. Determine the source specific 30-day rolling average operating limit using the lbs/MMBtu per milliamp value from Equation 11 in Equation 12, below. This sets the operating limit at the PM CPMS output value corresponding to 75 percent of the emission limit [§63.7530(b)(4)(ii)(B)(4)].

$$O_1 = z + \frac{0.78 (L)}{R} \quad (\text{Equation 12})$$

Where:

O₁ = the operating limit for the PM CPMS on a 30-day rolling average, in milliamps.

L = the source emission limit expressed in lbs/MMBtu,

z = the instrument zero in milliamps, determined from (B)(i), and

R = the relative lbs/MMBtu per milliamp for the PM CPMS, from Equation 11.

- f. If the average of the three PM compliance test runs is at or above 75 percent of the PM emission limit the facility must determine the 30-day rolling average operating limit by averaging the PM CPMS milliamp output corresponding to the three PM performance test runs that demonstrate compliance with the emission limit using Equation 13 and the facility must submit all compliance test and PM CPMS data according to the reporting requirements in paragraph (b)(4)(ii)(F) of §63.7530. [§63.7530(b)(4)(ii)(C)]

$$O_h = \frac{1}{n} \sum_{i=1}^n X_1 \quad (\text{Equation 13})$$

Where:

X₁ = the PM CPMS data points for all runs i,

n = the number of data points, and

O_h = the site specific operating limit, in milliamps.

- g. To determine continuous compliance, the PM CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control MUST BE RECORDED. Continuous compliance must be demonstrated by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average

operating parameter in units of the operating limit (milliamps) on a 30-day rolling average basis. Use Equation 14 to determine the 30-day rolling average [§63.7530(b)(4)(ii)(D)]:

$$30 - day = \frac{\sum_{i=l}^n Hpvi}{n} \quad (Equation 14)$$

Where:

30-day = 30-day average.

Hpvi = is the hourly parameter value for hour i

n = is the number of valid hourly parameter values collected over the previous 30 operating days.*

- h. Use EPA Method 5 of Appendix A to Part 60 of 40 CFR to determine PM emissions. For each performance test, conduct three separate runs under the conditions that exist when the affected source is operating at the highest load or capacity level reasonably expected to occur. Conduct each test run to collect a minimum sample volume specified in Table 1 or Table 2 of Subpart DDDDD, as applicable, for determining compliance with a new source limit or an existing source limit. Calculate the average of the results from three runs to determine compliance. The facility need not determine the PM collected in the impingers (“back half”) of the Method 5 particulate sampling train to demonstrate compliance with the PM standards of this subpart. This shall not preclude the Administrator from requiring a determination of the “back half” for other purposes. [§63.7530(b)(4)(ii)(E)]
 - i. For PM performance test reports used to set a PM CPMS operating limit, the electronic submission of the test report must also include the make and model of the PM CPMS instrument, serial number of the instrument, analytical principle of the instrument (e.g. beta attenuation), span of the instruments primary analytical range, milliamp value equivalent to the instrument zero output, technique by which this zero value was determined, and the average milliamp signals corresponding to each PM compliance test run.
3. For a PM wet scrubber, the minimum pressure drop and liquid flow rate as defined in §63.7575 must be established as the operating limits during the three-run performance test during compliance is demonstrated with the applicable limit. If the boiler or process heater uses a wet scrubber and separate performance tests for PM and TSM emissions are conducted, one set of minimum scrubber liquid flow rate and pressure drop operating limits must be established. The minimum scrubber effluent pH operating limit must be established during the HCl performance test. If multiple performance tests are conducted, the minimum liquid flow rate and pressure drop operating limits must be set at the higher of the minimum values established during the performance tests. [§63.7530(b)(4)(ii)(F)]
 4. For an Electrostatic Precipitator (ESP) operated with a wet scrubber, the minimum total secondary electric power input, as defined in §63.7575, must be established as the operating limit during the three-run performance test during which the facility demonstrates compliance with the applicable limit. These operating limits do not apply to ESP that are operated as dry controls without a wet scrubber. [§63.7530(b)(4)(iii)]

5. For a dry scrubber, the minimum sorbent injection rate must be established for each sorbent, as defined in §63.7575, as the operating limit during the three-run performance test during which compliance is demonstrated with the applicable limit. [§63.7530(b)(4)(iv)]
6. For activated carbon injection, the minimum activated carbon injection rate as defined in §63.7575 must be established as the operating limit during the three-run performance test during which the facility demonstrates compliance with the applicable limit. [§63.7530(b)(4)(v)]
7. The operating limit for boilers or process heaters with fabric filters that demonstrate continuous compliance through bag leak detection system is that a bag leak detection system be installed according to the requirements in §63.7525, and that each fabric filter must be operated such that the bag leak detection system alert is not activated more than 5 percent of the operating time during a 6-month period. [§63.7530(b)(4)(vi)]
8. For a minimum oxygen level, if multiple performance tests are conducted, the facility must set the minimum oxygen level at the lower of the minimum values established during the performance tests. [§63.7530(b)(4)(vii)]
9. The operating limit for boilers or process heaters that demonstrate continuous compliance with the HCl emission limit using a SO₂ CEMS is to install and operate the SO₂ according to the requirements in §63.7525(m) establish a maximum SO₂ emission rate equal to the highest hourly average SO₂ measurement during the most recent three-run performance test for HCl. [§63.7530(b)(4)(viii)]

Switching Fuels – is allowed (as long as it does not change the boiler category) provided fuel sampling demonstrates that pollutant inputs are not increasing. If the pollutant input is greater than the maximum established during the stack test, a new performance test must be conducted at the new higher input level to ensure that no limits are exceeded. [§63.7530(b)]

***Operating Day** is a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the boiler or process heater unit. It is not necessary for fuel to be combusted for the entire 24-hour period. For calculating rolling average emissions, an operating day does not include the hours of operation during start-up or shut-down.

APPENDIX F: Fuel Analysis**(Applies to most boilers and process heaters with emission limits)**

1. For each boiler or process heater that demonstrates compliance with the applicable emission limits in §63.7500 and Table 1 and Table 2 to Subpart DDDDD for Hydrogen Chloride (HCl), mercury (Hg), or Total Select Metals (TSM) through fuel analysis, the initial compliance requirement is to conduct a fuel analysis for each type of fuel burned in the boiler or process heater according to §63.7521, Table 6 to Subpart DDDDD and establish operating limits according to §63.7530, stated in Table 8 to Subpart DDDDD.
 - a) The fuels described in paragraphs (a)(2)(i) and (ii) of §63.7510, are exempt from fuel analysis and operating limit requirements. The fuels described in paragraph (a)(2)(ii) of §63.7510 are exempt from the chloride fuel analysis and operating limit requirements.
 - b) Boilers and process heaters that use a Continuous Emission Monitoring System (CEMS) for Hg or HCl are exempt from the performance testing and operating limit requirements specified in paragraph (a) of §63.7510 for the Hazardous Air Pollutant (HAP) HAP for which CEMS are used.

[§63.7510(b)]
2. If compliance is demonstrated with the Hg, HCl, or TSM emission limits based on fuel analysis, a monthly fuel analysis must be conducted according to §63.7521 for each type of fuel burned that is subject to an emission limit. The facility 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.
 - a) If the facility burns a new type of fuel, the facility must conduct a fuel analysis before burning the new type of fuel in the boiler or process heater. The facility must still meet all applicable continuous compliance requirements in §63.7540.
 - b) If each of 12 consecutive monthly fuel analyses demonstrates 75 percent or less of the compliance level, the facility may decrease the fuel analysis frequency to quarterly for that fuel.
 - c) If any quarterly sample exceeds 75 percent of the compliance level or the facility begins burning a new type of fuel, the facility must return to monthly monitoring for that fuel, until 12 months of fuel analyses are again less than 75 percent of the compliance level.

[§63.7515(e)]
3. For solid and liquid fuels, a fuel analyses must be conducted for chloride and Hg according to the procedures in paragraphs (b) through (e) of §63.7521, stated in Table 6 to Subpart DDDDD, as applicable.
 - a) For solid fuels and liquid fuels, the facility must also conduct fuel analyses for TSM if the facility is opting to comply with the TSM alternative standard.

4. For Gas 2 (other) fuels, the facility must conduct fuel analyses for Hg according to the procedures in paragraphs (b) through (e) of §63.7521, stated in Table 6 to Subpart DDDDD, as applicable.
 - a) For gaseous fuels, the facility may not use fuel analyses to comply with the TSM alternative standard or the HCl standard.
 - b) For purposes of complying with §63.7521, a fuel gas system that consists of multiple gaseous fuels collected and mixed with each other is considered a single fuel type and sampling and analysis is only required on the combined fuel gas system that will feed the boiler or process heater. Sampling and analysis of the individual gaseous streams prior to combining is not required.
5. Fuel analyses is NOT required for fuels used only for start-up, unit shut-down, and transient flame stability purposes.
6. Fuel analyses is required only for fuels and units that are subject to emission limits for Hg, HCl, or TSM in Table 1 and Table 2 to Subpart DDDDD.
7. Gaseous and liquid fuels are exempt from the sampling requirements in paragraphs (c) and (d) of §63.7521 as stated in Table 6 to Subpart DDDDD.

[§63.7521(a)]

Site-Specific Fuel Monitoring Plan

1. A site-specific fuel monitoring plan must be developed according to the following procedures and requirements in paragraphs (b)(1) and (2) of §63.7521, as listed below, if required to conduct fuel analyses as specified in §63.7510.
 - a. If the facility intends to use an alternative analytical method other than those required by Table 6 to Subpart DDDDD, the fuel analysis plan must be submitted to the Administrator for review and approval no later than 60 days before the date that the facility intends to conduct the initial compliance demonstration described in §63.7510.
 - b. The site-specific fuel analysis plan must include the information contained in paragraphs (b)(2)(i) through (vi) of §63.7521, as listed below:
 - i. The identification of all fuel types anticipated to be burned in each boiler or process heater.
 - ii. For each anticipated fuel type, the identification of whether the facility or a fuel supplier will be conducting the fuel analysis.
 - iii. For each anticipated fuel type, a detailed description of the sample location and specific procedures to be used for collecting and preparing the composite samples if the procedures are different from paragraph (c) or (d) of §63.7521. Samples should

be collected at a location that most accurately represents the fuel type, where possible, at a point prior to mixing with other dissimilar fuel types.

- iv. For each anticipated fuel type, the analytical methods from Table 6 to Subpart DDDDD, with the expected minimum detection levels, to be used for the measurement of chlorine or Hg.
- v. If the facility requests to use an alternative analytical method other than those required by Table 6 to Subpart DDDDD, the facility must also include a detailed description of the methods and procedures that the facility is proposing to use. Methods in Table 6 to Subpart DDDDD shall be used until the requested alternative is approved.
- vi. If the facility will be using fuel analysis from a fuel supplier in lieu of site-specific sampling and analysis, the fuel supplier must use the analytical methods required by Table 6 to Subpart DDDDD.

[§63.7521(b)(1) and §63.7521(b)(2)(i-vi)]

Fuel Sample Collection and Preparation

- 2. At a minimum, the facility must obtain three composite fuel samples for each fuel type according to the procedures in paragraph (c)(1) or (2) of §63.7521, as listed below, or the methods listed in Table 6 to Subpart DDDDD, or use an automated sampling mechanism that provides representative composite fuel samples for each fuel type that includes both coarse and fine material. At a minimum, for demonstrating initial compliance by fuel analysis, three composite samples must be obtained. For monthly fuel analyses, at a minimum, a single composite sample must be obtained. For fuel analyses as part of a performance stack test, as specified in §63.7510(a), a composite fuel sample must be obtained during each performance test run.
 - a. If sampling from a belt (or screw) feeder, collect fuel samples according to paragraphs (c)(1)(i) and (ii) of §63.7521, as listed below:
 - i. Stop the belt and withdraw a 6-inch wide sample from the full cross-section of the stopped belt to obtain a minimum two pounds of sample. All the material (fine and coarse) in the full cross-section must be collected. The sample must be transferred to a clean plastic bag.
 - 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 (*On 20 November 2015, the EPA removed the requirement at 63.7521(c)(2)(ii) that requires monthly composite fuel samples to be collected at 10-day intervals during the month*).

- b. If sampling from a fuel pile or truck, the fuel samples must be collected according to paragraphs (c)(2)(i) through (iii) of §63.7521, as listed below:
 - i. For each composite sample, select a minimum of five sampling locations uniformly spaced over the surface of the pile.
 - ii. At each sampling site, dig into the pile to a uniform depth of approximately 18 inches. A clean shovel must be inserted into the hole and withdraw a sample, making sure that large pieces do not fall off during sampling; use the same shovel to collect all samples.
 - iii. All samples must be transferred to a clean plastic bag for further processing.

[§63.7521(c)(2)(iii)] [§63.7521(c)(2)(i-ii)]

- 3. Each composite sample must be prepared according to the procedures in paragraphs (d)(1) through (7) of §63.7521, as listed below.
 - a. The facility must thoroughly mix and pour the entire composite sample over a clean plastic sheet.
 - b. The facility must break large sample pieces (e.g., larger than 3 inches) into smaller sizes.
 - c. The facility must make a pie shape with the entire composite sample and subdivide it into four equal parts.
 - d. The facility must separate one of the quarter samples as the first subset.
 - e. If this subset is too large for grinding, the facility must repeat the procedure in paragraph (d)(3) of §63.7521 with the quarter sample and obtain a one-quarter subset from this sample.
 - f. The facility must grind the sample in a mill
 - g. The facility must use the procedure in paragraph (d)(3) of §63.7521 to obtain a one-quarter subsample for analysis. If the quarter sample is too large, subdivide it further using the same procedure.

[§63.7521(d)(1-7)]

- 4. The facility must determine the concentration of pollutants in the fuel (Hg and/or chlorine and/or TSM) in units of pounds per million (lbs/MMBtu) of each composite sample for each fuel type according to the procedures in Table 6 to Subpart DDDDD, for use in Equations 7, 8, and 9 to Subpart DDDDD. [§63.7521(e)]

Fuel Analysis for “other Gas 1” fuels

5. To demonstrate that a gaseous fuel other than natural gas or refinery gas qualifies as an “other Gas 1” fuel, as defined in §63.7575, a fuel specification analyses must be conducted for Hg according to the procedures in paragraphs (g) through (i) of §63.7521, stated in Table 6 to Subpart DDDDD, as applicable, OR as an alternative where fuel specification analysis is not practical, Hg concentration in the exhaust gas must be measured when firing only the gaseous fuel to be demonstrated as an “other Gas 1” fuel in the boiler or process heater according to the procedures in Table 6 to Subpart DDDDD, except as specified in paragraph (f)(1) through (4) of §63.7521, as listed below.
 - a. The facility is not required to conduct the fuel specification analyses in paragraphs (g) through (i) of §63.7521 for natural gas or refinery gas.
 - b. The fuel specification analyses is not required for gaseous fuels that are subject to another subpart of Part 63, Part 60, Part 61, or Part 65.
 - c. The fuel specification analyses is not required on gaseous fuels for units that are complying with the limits for units designed to burn Gas 2 (other) fuels.
 - d. The fuel specification analyses is not required for gas streams directly derived from natural gas at natural gas production sites or natural gas plants.

[§63.7521(f)(1-4)]

6. The facility must develop a site-specific fuel analysis plan for other Gas 1 fuels and submit upon request to the EPA Administrator for review and approval according to the following procedures and requirements in paragraphs (g)(1) and (2) of §63.7521, as listed below.
 - a. If the facility intends to use an alternative analytical method other than those required by Table 6 to Subpart DDDDD, the facility must submit the fuel analysis plan to the Administrator for review and approval no later than 60 days before the date that the facility intends to conduct the initial compliance demonstration described in §63.7510. [§63.7521(g)(1)]
 - b. If the facility requests to use an alternative analytical method other than those required by Table 6 to Subpart DDDDD, the facility must also include a detailed description of the methods and procedures that the facility is proposing to use. Methods in Table 6 to Subpart DDDDD shall be used until the requested alternative is approved. [§63.7521(g)(2)(v)]
7. The facility must obtain a single fuel sample for each fuel type for fuel specification of gaseous fuels. [§63.7521(h)]

8. The concentration in the fuel of Hg must be determined in units of microgram per cubic meter, dry basis, of each sample for each other Gas 1 fuel type according to the procedures in Table 6 to Subpart DDDDD. [§63.7521(i)]

Procedures for Fuel Analysis (Equations)

1. To demonstrate compliance with an applicable emission limit through fuel analysis, the fuel analyses must be conducted according to §63.752 and follow the procedures in paragraphs (c)(1) through (5) of §63.7530, as listed below.
 - a. If the boiler or process heater burns more than one fuel type, the facility must determine the fuel mixture that would result in the maximum emission rates of the pollutants that the facility elects to demonstrate compliance through fuel analysis. [§63.7530(c)(1)]
 - b. The 90th percentile confidence level must be determined for the fuel pollutant concentration of the composite samples analyzed for each fuel type using the one-sided t-statistic test described in Equation 15 of [§63.7530(c)(2)]:

$$P90 = \text{mean} + (SD \times 1) \quad (\text{Equation 15})$$

Where:

P90 = 90th percentile confidence level pollutant concentration, in lbs/MMBtu.

Mean = Arithmetic average of the fuel pollutant concentration in the fuel samples analyzed according to §63.7521 in units of lbs/MMBtu.

SD = Standard deviation of the mean of pollutant concentration in the fuel samples analyzed according to §63.7521 in units of lbs/MMBtu. SD is calculated as the sample standard deviation divided by the square root of the number of samples.

t = t distribution critical value for 90th percentile ($t_{0.1}$) probability for the appropriate degrees of freedom (number of samples minus one) as obtained from a t-Distribution Critical Value Table.

- c. To demonstrate compliance with the applicable emission limit for HCl, the HCl emission rate that the facility calculates for the boiler or process heater using Equation 16 of §63.7530 must not exceed the applicable emission limit for HCl:

$$HCl = \sum_{i=1}^n (Ci90 \times Qi \times 1.028) \quad (\text{Equation 16})$$

Where:

HCl = HCl emission rate from the boiler or process heater in units of pounds per million Btu.

Ci90 = 90th percentile confidence level concentration of chlorine in fuel type, i, in units of pounds per million Btu as calculated according to Equation 15 of §63.7530,

Q_i = Fraction of total heat input from fuel type, i , based on the fuel mixture that has the highest content of chlorine during the initial compliance test. If multiple fuel types are not burned during the performance testing, it is not necessary to determine the value of this term. Insert a value of “1” for Q_i . For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

n = Number of different fuel types burned in the boiler or process heater for the mixture that has the highest content of chlorine.

1.028 = Molecular weight ratio of HCl to chlorine.

- d. To demonstrate compliance with the applicable emission limit for Hg, the Hg emission rate that the facility calculates for the boiler or process heater using Equation 17 of §63.7530 must not exceed the applicable emission limit for Hg [§63.7530(c)(4)]:

$$\text{Mercury} = \sum_{i=1}^n (Hg_{i90} \times Q_i) \quad (\text{Equation 17})$$

Where:

Mercury = Hg emission rate from the boiler or process heater in units of lbs/MMBtu.

Hg_{i90} = 90th percentile confidence level concentration of Hg in fuel, i , in units of lbs/MMBtu as calculated according to Equation 15 of §63.7530,

Q_i = Fraction of total heat input from fuel type, i , based on the fuel mixture that has the highest content of chlorine during the initial compliance test. If multiple fuel types are not burned during the performance testing, it is not necessary to determine the value of this term. Insert a value of “1” for Q_i . For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

n = Number of different fuel types burned in the boiler or process heater for the mixture that has the highest Hg content.

- e. To demonstrate compliance with the applicable emission limit for TSM for solid or liquid fuels, the TSM emission rate that the facility calculates for the boiler or process heater from solid fuels using Equation 18 of §63.7530 must not exceed the applicable emission limit for TSM [§63.7530(c)(5)]:

$$\text{Metals} = \sum_{i=1}^n (TSM_{i90} \times Q_i) \quad (\text{Equation 18})$$

Where:

Metals = TSM emission rate from the boiler or process heater in units of lbs/MMBtu.

TSM_{i90} = 90th percentile confidence level concentration of TSM in fuel, i , in units of lbs/MMBtu as calculated according to Equation 15 of §63.7530.

Q_i = Fraction of total heat input from fuel type, i , based on the fuel mixture that has the highest content of chlorine during the initial compliance test. If multiple fuel types are not

burned during the performance testing, it is not necessary to determine the value of this term. Insert a value of “1” for Q_i . For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

n = Number of different fuel types burned in the boiler or process heater for the mixture that has the highest TSM content.

Fuel Analysis Reporting

The facility must report the results of performance tests and the associated fuel analyses within 60 days after the completion of the performance tests. This report must also verify that the operating limits for each boiler or process heater have not changed or provide documentation of revised operating limits established according to §63.7530 and Table 7 to Subpart DDDDD, as applicable. The reports for all subsequent performance tests must include all applicable information required in §63.7550. [§63.7515(f)]

APPENDIX G: ACRONYMS

AFB	Air Force Base
AFCEC	Air Force Civil Engineer Center
BCE	Base Civil Engineer
Btu	British Thermal Unit
CAA	Clean Air Act
CE	Civil Engineering
CEMS	Continuous Emission Monitoring System
CFR	Code of Federal Regulations
CFRM	Continuous Flow Rate Monitor
CMS	Continuous Monitoring System
CO	Carbon Monoxide
COMS	Continuous Opacity Monitoring System
CONUS	Continental United States
DoD	Department of Defense
DOE	Department of Energy
dscf	Dry Standard Cubic Feet
dscfm	Dry Standard Cubic Feet per Minute
EPA	United States Environmental Protection Agency
EPAct	Energy Policy Act
ERC	Emission Reduction Credit
ESP	Electrostatic Precipitator
EtO	Ethylene Oxide
FF	Fabric Filter
FR	Federal Register
ft.	Foot (Feet)
g/L	Grams per Liter
GACTION	Generally Available Control Technologies
HAP	Hazardous Air Pollutant
HCl	Hydrogen Chloride
HHV	High Heat Value
hr	Hour(s)
HVLP	High Volume Low Pressure
kW	Kilowatt(s)
lb	Pound(s)
LFG	Landfill Gas
LPG	Liquefied Petroleum Gas
MACT	Maximum Achievable Control Technology
MMBtu	Million British Thermal Units (M = One Thousand, MM = One Million)
N ₂ O	Nitrous Oxide
NAAQS	National Ambient Air Quality Standards
NESHAP	National Emission Standards for Hazardous Air Pollutants
NSPS	New Source Performance Standards
NHSM	Non-Hazardous Secondary Material

NO ₂	Nitrogen Dioxide
NO _x	Nitrogen Oxides
PM	Particulate Matter – Aerodynamic diameter unspecified
ppm	Parts per Million
PTE	Potential-To-Emit
SO ₂	Sulfur Dioxide
SO _x	Sulfur Oxides
TOC	Total Organic Compounds
tpy	Tons per Year
TSP	Total Suspended Particulate
ULSD	Ultra Low Sulfur Diesel
USAF/AF	United States Air Force
yr	Year