## ENVIRONMENTAL PROTECTION AGENCY

**40 CFR Part 63**

**[OAR–2002–0058; FRL–7633–9]**

**RIN 2060–AG69**

## National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters

**AGENCY:** Environmental Protection Agency (EPA).

**ACTION:** Final rule.

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**SUMMARY:** The EPA is promulgating national emission standards for hazardous air pollutants (NESHAP) for industrial, commercial, and institutional boilers and process heaters. The EPA has identified industrial, commercial, and institutional boilers and process heaters as major sources of hazardous air pollutants (HAP) emissions. The final rule will implement section 112(d) of the Clean Air Act (CAA) by requiring all major sources to meet HAP emissions standards reflecting the application of the maximum achievable control technology (MACT). The final rule is expected to reduce HAP emissions by 50,600 to 58,000 tons per year (tpy).

The HAP emitted by facilities in the boiler and process heater source category include arsenic, cadmium, chromium, hydrogen chloride (HCl), hydrogen fluoride, lead, manganese, mercury, nickel, and various organic HAP. Exposure to these substances has been demonstrated to cause adverse health effects such as irritation to the lung, skin, and mucus membranes, effects on the central nervous system, kidney damage, and cancer. These adverse health effects associated with the exposure to these specific HAP are further described in this preamble. In general, these findings only have been shown with concentrations higher than those typically in the ambient air.

The final rule contains numerous compliance provisions including health-based compliance alternatives for the hydrogen chloride and total selected metals emission limits.

**DATES:** The final rule is effective November 12, 2004. The incorporation by reference of certain publications listed in the final rule is approved by the Director of the Federal Register as of November 12, 2004.

**ADDRESSES:** The official public docket is the collection of materials that is available for public viewing at the Office of Air and Radiation Docket and Information Center (Air Docket) in the EPA Docket Center, Room B–102, 1301 Constitution Avenue, NW., Washington, DC.

**FOR FURTHER INFORMATION CONTACT:** For information concerning applicability and rule determinations, contact your State or local representative or appropriate EPA Regional Office representative. For information concerning rule development, contact Jim Eddinger, Combustion Group, Emission Standards Division (C439–01), U.S. EPA, Research Triangle Park, North Carolina 27711, telephone number (919) 541–5426, fax number (919) 541–5450, electronic mail address *eddinger.jim@epa.gov.*

**SUPPLEMENTARY INFORMATION:** Regulated Entities. Categories and entities potentially regulated by this action include:

| Category | NAICS code | SIC code | Examples of potentially regulated entities |
|---|---|---|---|
| Any industry using a boiler or process heater as defined in the final rule. | 211 | 13 | Extractors of crude petroleum and natural gas. |
| | 321 | 24 | Manufacturers of lumber and wood products. |
| | 322 | 26 | Pulp and paper mills. |
| | 325 | 28 | Chemical manufacturers. |
| | 324 | 29 | Petroleum refineries, and manufacturers of coal products. |
| | 316, 326, 339 | 30 | Manufacturers of rubber and miscellaneous plastic products. |
| | 331 | 33 | Steel works, blast furnaces. |
| | 332 | 34 | Electroplating, plating, polishing, anodizing, and coloring. |
| | 336 | 37 | Manufacturers of motor vehicle parts and accessories. |
| | 221 | 49 | Electric, gas, and sanitary services. |
| | 622 | 80 | Health services. |
| | 611 | 82 | Educational services. |

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this action. This table lists examples of the types of entities EPA is now aware could potentially be regulated by this action. Other types of entities not listed could also be affected. To determine whether your facility, company, business, organization, etc., is regulated by this action, you should examine the applicability criteria in § 63.7485 of the final rule. If you have any questions regarding the applicability of this action to a particular entity, consult the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

*Docket.* The EPA has established an official public docket for this action under Docket ID No. OAR–2002–0058 and Docket ID No. A–96–47. The official public docket consists of the documents specifically referenced in this action, any public comments received, and other information related to this action. All items may not be listed under both docket numbers, so interested parties should inspect both docket numbers to ensure that they have received all materials relevant to the final rule. Although a part of the official docket, the public docket does not include Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. The official public docket is the collection of materials that is available for public viewing at the Office of Air and Radiation Docket and Information Center (Air Docket) in the EPA Docket Center, Room B102, 1301 Constitution Ave., NW., Washington, DC. The EPA Docket Center Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Reading Room is (202) 566–1744, and the telephone number for the Air and Radiation Docket is (202)

566–1742. A reasonable fee may be charged for copying docket materials.

*Electronic Access.* You may access this **Federal Register** document electronically through the EPA Internet under the ''**Federal Register**'' listings at *http://www.epa.gov/fedrgstr/.*

An electronic version of the public docket is available through EPA's electronic public docket and comment system, EPA Dockets. You may use EPA Dockets at *http://www.epa.gov/edocket/* to view public comments, access the index listing of the contents of the official public docket, and to access those documents in the public docket that are available electronically. Once in the system, select ''search,'' then key in the appropriate docket identification number.

*Worldwide Web (WWW).* In addition to being available in the docket, an electronic copy of the final rule is also available on the WWW through the Technology Transfer Network (TTN). Following signature, a copy of the final rule will be posted on the TTN policy and guidance page for newly proposed or promulgated rules at the following address: *http://www.epa.gov/ttn/oarpg.* The TTN provides information and technology exchange in various areas of air pollution control. If more information regarding the TTN is needed, call the TTN HELP line at (919) 541–5384.

*Judicial Review.* Under section 307(b)(1) of the CAA, judicial review of the NESHAP is available by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit by November 12, 2004. Only those objections to the final rule that were raised with reasonable specificity during the period for public comment may be raised during judicial review. Under section 307(b)(2) of the CAA, the requirements that are the subject of the final rule may not be challenged later in civil or criminal proceedings brought by EPA to enforce these requirements.

*Background Information Document.* The EPA proposed the NESHAP for industrial, commercial, and institutional boilers and process heaters on January 13, 2003 (68 FR 1660) and received 218 comment letters on the proposal. A memorandum ''National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters, Summary of Public Comments and Responses,'' containing EPA's responses to each public comment is available in Docket No. OAR–2002–0058.

*Outline.* The information presented in this preamble is organized as follows:

## I. Background Information

### *A. What Is the Statutory Authority for the Final Rule?*

Section 112 of the CAA requires us to list categories and subcategories of major sources and area sources of HAP and to establish NESHAP for the listed source categories and subcategories. Industrial boilers, commercial and institutional boilers, and process heaters were listed on July 16, 1992 (57 FR 31576). Major sources of HAP are those that have the potential to emit greater than 10 tpy of any one HAP or 25 tpy of any combination of HAP.

### *B. What Criteria Are Used in the Development of NESHAP?*

Section 112(c)(2) of the CAA requires that we establish NESHAP for control of HAP from both existing and new major sources, based upon the criteria set out in CAA section 112(d). The CAA requires the NESHAP to reflect the maximum degree of reduction in emissions of HAP that is achievable, taking into consideration the cost of achieving the emission reduction, any non-air quality health and environmental impacts, and energy requirements. This level of control is commonly referred to as the MACT.

The minimum control level allowed for NESHAP (the minimum level of stringency for MACT) is the ''MACT floor,'' as defined under section 112(d)(3) of the CAA. The MACT floor for existing sources is the emission limitation achieved by the average of the best-performing 12 percent of existing sources for categories and subcategories with 30 or more sources, or the average of the best-performing five sources for categories or subcategories with fewer than 30 sources. For new sources, the MACT floor cannot be less stringent than the emission control achieved in practice by the best-controlled similar source.

### *C. How Was the Final Rule Developed?*

We proposed standards for industrial, commercial, and institutional boilers and process heaters on January 13, 2003 (68 FR 1660). Public comments were solicited at the time of proposal. The public comment period lasted from January 13, 2003, to March 14, 2003.

We received a total of 218 public comment letters on the proposed rule. Comments were submitted by industry trade associations, owners/operators of boilers and process heaters, State regulatory agencies and their representatives, and environmental groups. Today's final rule reflects our consideration of all of the comments and additional information received. Major public comments on the proposed rules, along with our responses to those comments, are summarized in this preamble.

### *D. What Is the Relationship Between the Final Rule and Other Combustion Rules?*

The final rule regulates source categories covering industrial boilers, institutional and commercial boilers, and process heaters. These source categories potentially include combustion units that are already regulated by other MACT standards. Therefore, we are excluding from the final rule any combustion units that are already or will be subject to regulation under another MACT standard under 40 CFR part 63.

Combustion units that are regulated by other standards and are therefore excluded from the final rule include solid waste incineration units covered by section 129 of the CAA; boilers or process heaters required to have a permit under section 3005 of the Solid Waste Disposal Act or covered by the hazardous waste combustor NESHAP in 40 CFR part 63, subpart EEE[1]; and recovery boilers or furnaces covered by 40 CFR part 63, subpart MM.

With regards to solid waste incineration units covered by section 129 of the CAA, EPA solicited on February 17, 2004 (69 FR 7390) public comments on the definition of ''commercial and industrial solid waste incineration unit'' for the purpose of determining which combustion sources to regulate under section 129 and which to regulate under section 112 (*e.g.*, boilers and process heaters). As stated above, combustion units covered under section 129 are not subject to the final rule.

Electric utility steam generating units are not subject to the final rule. An electric utility steam generating unit is a fossil fuel-fired combustion unit of more than 25 megawatts that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 megawatts electrical output to any utility power distribution system for sale is considered an electric utility steam generating unit. Non-fossil fuel-fired utility boilers and electric utility steam generating units less than 25 megawatts are covered by the final rule.

In 1986, EPA codified the NSPS for industrial boilers (40 CFR part 60, subparts Db and Dc) and revised portions of them in 1999. The NSPS regulates emissions of particulate matter (PM), sulfur dioxide, and nitrogen oxides from boilers constructed after June 19, 1984. Sources subject to the NSPS are also subject to the final rule because the final rule regulates sources of hazardous air pollutants while the NSPS does not. However, in developing the final rule for industrial, commercial, and institutional boilers and process heaters, EPA minimized the monitoring requirements, testing requirements, and recordkeeping requirements to avoid duplicating requirements.

Because of the broad applicability of the final rule due to the definition of a process heater, certain process heaters could appear to fit the applicability of another existing MACT rule. We have, therefore, included in the list of combustion units not subject to the final rule refining kettles subject to the secondary lead MACT rule (40 CFR part 63, subpart X); ethylene cracking furnaces covered by 40 CFR part 63, subpart YY; and blast furnace stoves described in the EPA document entitled ''National Emission Standards for Hazardous Air Pollutants for Integrated Iron and Steel Plants—Background Information for Proposed Standards'' (EPA–453/R–01–005).

### *E. What Are the Health Effects of Pollutants Emitted From Industrial, Commercial, and Institutional Boilers and Process Heaters?*

The final rule protects air quality and promotes the public health by reducing emissions of some of the HAP listed in section 112(b)(1) of the CAA. As noted above, emissions data collected during development of the proposed rule show that HCl emissions represent the predominant HAP emitted by industrial boilers. Industrial boilers emit lesser amounts of hydrogen fluoride, chlorine, metals (arsenic, cadmium, chromium, mercury, manganese, nickel, and lead), and organic HAP emissions. Although numerous organic HAP may be emitted from industrial boilers and process heaters, only a few account for essentially all the mass of organic HAP emissions. These organic HAP are: Formaldehyde, benzene, and acetaldehyde.

Exposure to high levels of these HAP is associated with a variety of adverse health effects. These adverse health effects include chronic health disorders (*e.g.*, irritation of the lung, skin, and mucus membranes, effects on the central nervous system, and damage to the kidneys), and acute health disorders (*e.g.*, lung irritation and congestion, alimentary effects such as nausea and vomiting, and effects on the kidney and central nervous system). We have classified three of the HAP as human carcinogens and five as probable human carcinogens. Our screening assessment for respiratory HAP and for central nervous system (CNS) HAP, using health protective assumptions, indicates that manganese and chlorine are the only boiler-related HAP that are reasonably expected to approach health based criteria concentrations at receptor locations at or beyond facility boundaries. Emissions of all other HAP modeled on an individual basis appears to be insignificant relative to the concentration that would produce the health effects that they represent. The maximal hazard index (HI) for summation of the HAP modeled in the screening assessment for respiratory effects, including chlorine, was less than 3. The maximal HI for summation of the HAP modeled in the screening assessment for CNS effects, including manganese, was less than 3. Therefore, effects noted below for HAP at high concentrations are not expected to occur prior or after regulation as a result of emissions from these facilities, and are provided to illustrate the nature of the contaminant's effects at high dose. A screening assessment was also conducted for acute effects, and no exceedances were seen. Therefore, potential acute effects are not discussed below. However, to the extent the adverse effects do occur, the final rule will reduce emissions and subsequent exposures.

#### Acetaldehyde

Acetaldehyde is ubiquitous in the environment and may be formed in the body from the breakdown of ethanol (ethyl alcohol). In humans, symptoms of chronic (long-term) exposure to acetaldehyde resemble those of alcoholism. Long-term inhalation exposure studies in animals reported effects on the nasal epithelium and mucous membranes, and increased kidney weight. The EPA has classified acetaldehyde as a probable human carcinogen (Group B2) based on animal studies that have shown nasal tumors in rats and laryngeal tumors in hamsters.

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[1] Please note that boilers that burn small quantities of hazardous waste under the exemptions provided by 40 CFR 266.108 are subject to today's final rule.

Arsenic

Chronic (long-term) inhalation exposure to inorganic arsenic in humans is associated with irritation of the skin and mucous membranes. Human data suggest a relationship between inhalation exposure for women working at or living near metal smelters and an increased risk of reproductive effects. Inorganic arsenic exposure in humans by the inhalation route has been shown to be strongly associated with lung cancer, while ingestion of inorganic arsenic in humans has been linked to a form of skin cancer and also to bladder, liver, and lung cancer. The EPA has classified inorganic arsenic as a Group A, human carcinogen.

Benzene

Chronic (long-term) inhalation exposure has caused various disorders in the blood, including reduced numbers of red blood cells. Increased incidence of leukemia (cancer of the tissues that form white blood cells) has been observed in humans occupationally exposed to benzene. The EPA has classified benzene as a Group A, known human carcinogen.

Beryllium

Chronic (long-term) inhalation exposure of humans to high levels of beryllium has been reported to cause chronic beryllium disease (berylliosis), in which granulomatous (noncancerous) lesions develop in the lung. Inhalation exposure to high levels of beryllium has been demonstrated to cause lung cancer in rats and monkeys. Human studies are limited, but suggest a causal relationship between beryllium exposure and an increased risk of lung cancer. We have classified beryllium as a Group B1, probable human carcinogen, when inhaled; data are inadequate to determine whether beryllium is carcinogenic when ingested.

Cadmium

Chronic (long-term) inhalation or oral exposure to cadmium leads to a build-up of cadmium in the kidneys that can cause kidney disease. Cadmium has been shown to be a developmental toxicant at high doses in animals, resulting in fetal malformations and other effects, but no conclusive evidence exists in humans. Animal studies have demonstrated an increase in lung cancer from long-term inhalation exposure to cadmium. The EPA has classified cadmium as a Group B1, probable carcinogen.

Chlorine

Chlorine is a commonly used household cleaner and disinfectant. Chlorine is an irritant to the eyes, the upper respiratory tract, and lungs. Chronic (long-term) exposure to chlorine gas in workers has resulted in respiratory effects, including eye and throat irritation and airflow obstruction. No information is available on the carcinogenic effects of chlorine in humans from inhalation exposure. A National Toxicology Program (NTP) study showed no evidence of carcinogenic activity in male rats or male and female mice, and equivocal evidence in female rats, from ingestion of chlorinated water. The EPA has not classified chlorine for potential carcinogenicity.

Chromium

Chromium may be emitted by industrial boilers in two forms, trivalent chromium (chromium III) or hexavalent chromium (chromium VI). The respiratory tract is the major target organ for chromium VI toxicity for inhalation exposures. Bronchitis, decreased pulmonary function, pneumonia, and other respiratory effects have been noted from chronic high dose exposure in occupational settings to chromium VI. Limited human studies suggest that chromium VI inhalation exposure may be associated with complications during pregnancy and childbirth, while animal studies have not reported reproductive effects from inhalation exposure to chromium VI. Human and animal studies have clearly established that inhaled chromium VI is a carcinogen, resulting in an increased risk of lung cancer. The EPA has classified chromium VI as a Group A, human carcinogen.

Chromium III is less toxic than chromium VI. The respiratory tract is also the major target organ for chromium III toxicity, similar to chromium VI. Chromium III is an essential element in humans, with a daily intake of 50 to 200 micrograms per day recommended for an adult. The body can detoxify some amount of chromium VI to chromium III. The EPA has not classified chromium III with respect to carcinogenicity.

Formaldehyde

Exposure to formaldehyde irritates the eyes, nose, and throat. Reproductive effects, such as menstrual disorders and pregnancy problems, have been reported in female workers exposed to high levels of formaldehyde. Limited human studies have reported an association between formaldehyde exposure and lung and nasopharyngeal cancer. Animal inhalation studies have reported an increased incidence of nasal squamous cell cancer. The EPA considers formaldehyde a probable human carcinogen (Group B2).

Hydrogen chloride

Hydrogen chloride, also called hydrochloric acid, is corrosive to the eyes, skin, and mucous membranes at high concentration. Chronic (long-term) occupational exposure to high levels of hydrochloric acid has been reported to cause gastritis, bronchitis, and dermatitis in workers. Prolonged exposure to lower concentrations may also cause dental discoloration and erosion. No information is available on the reproductive or developmental effects of hydrochloric acid in humans. In rats exposed to high levels of hydrochloric acid by inhalation, altered estrus cycles have been reported in females and increased fetal mortality and decreased fetal weight have been reported in offspring. The EPA has not classified hydrochloric acid for carcinogenicity.

Hydrogen fluoride

Chronic (long-term) exposure to fluoride at low levels has a beneficial effect of dental cavity prevention and may also be useful for the treatment of osteoporosis. Exposure to higher levels of fluoride may cause dental fluorosis. One study reported menstrual irregularities in women occupationally exposed to fluoride. The EPA has not classified hydrogen fluoride for carcinogenicity.

Lead

Lead can cause a variety of effects at low dose levels. Chronic (long-term) exposure to high levels of lead in humans results in effects on the blood, central nervous system (CNS), blood pressure, and kidneys. Children are particularly sensitive to the chronic effects of lead, with slowed cognitive development, reduced growth and other effects reported. Reproductive effects, such as decreased sperm count in men and spontaneous abortions in women, have been associated with lead exposure. The developing fetus is at particular risk from maternal lead exposure, with low birth weight and slowed postnatal neurobehavioral development noted. Human studies are inconclusive regarding lead exposure and cancer, while animal studies have reported an increase in kidney cancer from high-dose lead exposure by the oral route. The EPA has classified lead as a Group B2, probable human carcinogen.

Manganese

Health effects in humans have been associated with both deficiencies and excess intakes of manganese. Chronic (long-term) exposure to low levels of manganese in the diet is considered to be nutritionally essential in humans, with a recommended daily allowance of 2 to 5 milligrams per day (mg/d). Chronic exposure to high levels of manganese by inhalation in humans results primarily in CNS effects. Visual reaction time, hand steadiness, and eye-hand coordination were affected in chronically-exposed workers. Impotence and loss of libido have been noted in male workers afflicted with manganism attributed to high-dose inhalation exposures. The EPA has classified manganese in Group D, not classifiable as to carcinogenicity in humans.

Mercury

Mercury exists in three forms: Elemental mercury, inorganic mercury compounds (primarily mercuric chloride), and organic mercury compounds (primarily methyl mercury). Each form exhibits different health effects. Various major sources may release elemental or inorganic mercury; environmental methyl mercury is typically formed by biological processes after mercury has precipitated from the air.

Chronic (long-term) exposure to elemental mercury in humans also affects the CNS, with effects such as increased excitability, irritability, excessive shyness, and tremors. The EPA has not classified elemental mercury with respect to cancer.

The major effect from chronic exposure to inorganic mercury is kidney effects. Reproductive and developmental animal studies have reported effects such as alterations in testicular tissue, increased embryo resorption rates, and abnormalities of development. Mercuric chloride (an inorganic mercury compound) exposure has been shown to result in tumors in experimental animals. The EPA has classified mercuric chloride as a Group C, possible human carcinogen.

Nickel

Nickel is an essential element in some animal species, and it has been suggested it may be essential for human nutrition. Nickel dermatitis, consisting of itching of the fingers, hand and forearms, is the most common effect in humans from chronic (long-term) skin contact with nickel. Respiratory effects have also been reported in humans from inhalation exposure to nickel. No information is available regarding the reproductive or developmental effects of nickel in humans, but animal studies have reported such effects, although a consistent dose-response relationship has not been seen. Nickel forms released from industrial boilers include soluble nickel compounds, nickel subsulfide, and nickel carbonyl. Human and animal studies have reported an increased risk of lung and nasal cancers from exposure to nickel refinery dusts and nickel subsulfide. Animal studies of soluble nickel compounds (*i.e.*, nickel carbonyl) have reported lung tumors. The EPA has classified nickel refinery subsulfide as Group A, human carcinogens and nickel carbonyl as a Group B2, probable human carcinogen.

Selenium

Selenium is a naturally occurring substance that is toxic at high concentrations but is also a nutritionally essential element. Studies of humans chronically (long-term) exposed to high levels of selenium in food and water have reported discoloration of the skin, pathological deformation and loss of nails, loss of hair, excessive tooth decay and discoloration, lack of mental alertness, and listlessness. The consumption of high levels of selenium by pigs, sheep, and cattle has been shown to interfere with normal fetal development and to produce birth defects. Results of human and animal studies suggest that supplementation with some forms of selenium may result in a reduced incidence of several tumor types. One selenium compound, selenium sulfide, is carcinogenic in animals exposed orally. We have classified elemental selenium as a Group D, not classifiable as to human carcinogenicity, and selenium sulfide as a Group B2, probable human carcinogen.

## II. Summary of the Final Rule

### *A. What Source Categories and Subcategories Are Affected by the Final Rule?*

The final rule affects industrial boilers, institutional and commercial boilers, and process heaters. In the final rule, process heater means an enclosed device using controlled flame, that is not a boiler, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to heat a transfer material for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not directly come into 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. Boiler means an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water. Waste heat boilers are excluded from the definition of boiler. A waste heat boiler (or heat recovery steam generator) means a device, without controlled flame combustion, that recovers normally unused energy and converts it to usable heat. Waste heat boilers incorporating duct or supplemental burners that are designed to supply 50 percent or more of the total rated heat input capacity of the waste heat boiler are considered boilers and not waste heat boilers. Emissions from a combustion unit with a waste heat boiler are regulated by the applicable standards for the particular type of combustion unit. For example, emissions from a commercial or industrial solid waste incineration unit, or other incineration unit with a waste heat boiler are regulated by standards established under section 129 of the CAA.

Hot water heaters also are not regulated under the final rule. A hot water heater is a closed vessel, with a capacity of no more than 120 U.S. gallons, in which water is heated by combustion of gaseous or liquid fuel and is withdrawn for use external to the vessel at pressures not exceeding 160 pounds per square inch gauge and water temperatures not exceeding 210 degree Fahrenheit (99 degrees Celsius).

Temporary boilers also are not regulated under the final rule. A temporary boiler is any gaseous or liquid fuel-fired boiler that is designed, and is capable of, being carried or moved from one location to another, and remains at any one location for less than 180 consecutive days. Additionally, any new temporary boiler that replaces an existing temporary boiler and is intended to perform the same or similar function will be included in the determination of the consecutive 180-day time period.

Boilers or process heaters that are used specifically for research and development are not regulated under the final rule. However, units that only provide steam to a process at a research and development facility are still subject to the final rule.

### *B. What Is the Affected Source?*

In the final rule, the affected source is defined as follows: (1) The collection of all existing industrial, commercial, or institutional boilers and process heaters within a subcategory located at a major source; or (2) each new or reconstructed industrial, commercial or institutional boiler and process heater located at a major source.

The affected source does not include combustion units that are subject to another standard under 40 CFR part 63, or covered by other standards listed in this preamble.

### *C. What Pollutants Are Emitted and Controlled?*

Boilers and process heaters can emit a wide variety of HAP, depending on the material burned. Because of the large number of HAP potentially present in emissions and the disparity in the quantity and quality of the emissions information available, we use several surrogates to control multiple HAP in the final rule. This will reduce the burden of implementation and compliance on both regulators and the regulated community.

We grouped the HAP into four common categories: mercury, non-mercury metallic HAP, inorganic HAP, and organic HAP. In general, the pollutants within each group have similar characteristics and can be controlled with the same techniques.

Next, we identified compounds that could be used as surrogates for all the compounds in each pollutant category. For the non-mercury metallic HAP, we chose to use PM as a surrogate. Most, if not all, non-mercury metallic HAP emitted from combustion sources will appear on the flue gas fly-ash. Therefore, the same control techniques that would be used to control the fly-ash PM will control non-mercury metallic HAP. Particulate matter was also chosen instead of specific metallic HAP because all fuels do not emit the same type and amount of metallic HAP but most generally emit PM. The use of PM as a surrogate will also eliminate the cost of performance testing to comply with numerous standards for individual metals.

However, we are sensitive to the fact that some sources burn fuels containing very little metals, but would have sufficient PM emissions to require control under the PM provisions of the proposed rule. In such cases, PM would not be an appropriate surrogate for metallic HAP. Therefore, in the final rule, an alternative metals emission limit is included. A source may choose to comply with the alternative metals emissions limit instead of the PM limit to meet the final rule.

For inorganic HAP, we chose to use HCl as a surrogate. The emissions test information available indicate that the primary inorganic HAP emitted from boilers and process heaters are acid gases, with HCl present in the largest amounts. Other inorganic compounds emitted are found in much smaller quantities. Also, control technologies that would reduce HCl would also control other inorganic compounds that are acid gases. Thus, the best controls for HCl would also be the best controls for other inorganic HAP that are acid gases. Therefore, HCl is a good surrogate for inorganic HAP because controlling HCl will result in a corresponding control of other inorganic HAP emissions.

For organic HAP, we chose to use carbon monoxide (CO) as a surrogate to represent the variety of organic compounds, including dioxins, emitted from the various fuels burned in boilers and process heaters. Because CO is a good indicator of incomplete combustion, there is a direct correlation between CO emissions and the formation of organic HAP emissions. Monitoring equipment for CO is readily available, which is not the case for organic HAP. Also, it is significantly easier and less expensive to measure and monitor CO emissions than to measure and monitor emissions of each individual organic HAP. Therefore, using CO as a surrogate for organic HAP is a reasonable approach because minimizing CO emissions will result in minimizing organic HAP emissions.

### *D. Does the Final Rule Apply to Me?*

The final rule applies to you if you own or operate a boiler or process heater located at a major source meeting the requirements in the final rule.

### *E. What Are the Emission Limitations and Work Practice Standards?*

You must meet the emission limits and work practice standards for the subcategories in Table 1 of this preamble for each of the pollutants listed. Emission limits and work practice standards were developed for new and existing sources; and for large, small, and limited use solid, liquid, and gas fuel-fired units. Large units are those watertube boilers and process heaters with heat input capacities greater than 10 million British thermal units per hour (MMBtu/hr). Small units are any firetube boilers or any boiler and process heater with heat input capacities less than or equal to 10 MMBtu/hr. Limited use units are those large units with capacity utilizations less than or equal to 10 percent as required in a federally enforceable permit.

If your new or existing boiler or process heater is permitted to burn a solid fuel (either as a primary fuel or a backup fuel), or any combination of solid fuel with liquid or gaseous fuel, the unit is in one of the solid subcategories. If your new or existing boiler or process heater burns a liquid fuel, or a liquid fuel in combination with a gaseous fuel, the unit is in one of the liquid subcategories, except if the unit burns liquid only during periods of gas curtailment. If your new or existing boiler or process heater burns a gaseous fuel not combined with any liquid or solid fuels, or burns liquid fuel only during periods of gas curtailment or gas supply emergencies, the unit is in the gaseous subcategory.

TABLE 1—EMISSION LIMITS AND WORK PRACTICE STANDARDS FOR BOILERS AND PROCESS HEATERS

[(Pounds per million British thermal units (lb/MMBtu)]

| Source | Subcategory | Particulate Matter (PM) | or | Total Selected Metals | Hydrogen Chloride (HCl) | Mercury (Hg) | Carbon Monoxide (CO) (ppm) |
|---|---|---|---|---|---|---|---|
| New or reconstructed Boiler or Process Heater. | Solid Fuel, Large Unit. | 0.025 | or | 0.0003 | 0.02 | 0.000003 | 400 (@7% oxygen). |
| | Solid Fuel, Small Unit. | 0.025 | or | 0.0003 | 0.02 | 0.000003 | |
| | Solid Fuel, Limited Use. | 0.025 | or | 0.0003 | 0.02 | 0.000003 | 400 (@7% oxygen). |
| | Liquid Fuel, Large Unit. | 0.03 | ...... | ........................ | 0.0005 | ............................. | 400 (@3% oxygen). |

TABLE 1—EMISSION LIMITS AND WORK PRACTICE STANDARDS FOR BOILERS AND PROCESS HEATERS—Continued

[(Pounds per million British thermal units (lb/MMBtu)]

| Source | Subcategory | Particulate Matter (PM) | or | Total Selected Metals | Hydrogen Chloride (HCl) | Mercury (Hg) | Carbon Monoxide (CO) (ppm) |
|---|---|---|---|---|---|---|---|
| | Liquid Fuel, Small Unit. | 0.03 | ...... | ........................ | 0.0009 | ............................. | |
| | Liquid Fuel, Limited Use. | 0.03 | ...... | ........................ | 0.0009 | ............................. | 400 (@3% oxygen). |
| | Gaseous Fuel, Large Unit. | | ...... | ........................ | ............................. | ............................. | 400 (@3% oxygen). |
| | Gaseous Fuel, Small Unit. | | ...... | ........................ | ............................. | ............................. | |
| | Gaseous Fuel Limited Use. | | ...... | ........................ | ............................. | ............................. | 400 (@3% oxygen). |
| Existing Boiler or Process Heater. | Solid Fuel, Large Unit. | 0.07 | or | 0.001 | 0.09 | 0.000009 | |
| | Solid Fuel, Small Unit. | | ...... | ........................ | ............................. | ............................. | |
| | Solid Fuel, Limited Use. | 0.21 | or | 0.004 | ............................. | ............................. | |
| | Liquid Fuel, Large Unit. | | ...... | ........................ | ............................. | ............................. | |
| | Liquid Fuel, Small Unit. | | ...... | ........................ | ............................. | ............................. | |
| | Liquid Fuel, Limited Use. | | ...... | ........................ | ............................. | ............................. | |
| | Gaseous Fuel ...... | | ...... | ........................ | ............................. | ............................. | |

For solid fuel-fired boilers or process heaters, sources may choose one of two emission limit options: (1) Existing and new affected units may choose to limit PM emissions to the level listed in Table 1 of this preamble, or (2) existing and new affected units may choose to limit total selected metals emissions to the level listed in Table 1 of this preamble. Sources meeting the emission limits must also meet operating limits.

We have provided several compliance alternatives in the final rule. Sources may choose to demonstrate compliance based on the fuel pollutant content. Sources are also allowed to demonstrate compliance for existing large solid fuel units using emissions averaging.

### *F. What Are the Testing and Initial Compliance Requirements?*

As the owner or operator of a new or existing boiler or process heater, you must conduct performance tests (*i.e.* stack testing) or an initial fuel analysis to demonstrate compliance with any applicable emission limits. The applicable emission limits and, therefore, the required performance tests and fuel analysis are different depending on the subcategory classification of the unit. Existing units in the small solid fuel subcategory and existing units in any of the liquid or gaseous fuel subcategories do not have applicable emission limits and, therefore, are not required to conduct stack tests or fuel analyses. Other units are required to conduct the following compliance tests or fuel analyses where applicable:

(1) Conduct initial and annual stack tests to determine compliance with the PM emission limits using EPA Method 5 or Method 17 in appendix A to part 60 of this chapter.

(2) Affected sources in the solid fuel subcategories may choose to comply with an alternative total selected metals emission limit instead of PM. Sources would conduct initial and annual stack tests to determine compliance with the total selected metals emission limit using EPA Method 29 in appendix A to part 60 of this chapter.

(3) Conduct initial and annual stack tests to determine compliance with the mercury emission limits using EPA Method 29 in appendix A to part 60 of this chapter or the ASTM D6784–02.

(4) Conduct initial and annual stack tests to determine compliance with the HCl emission limits using EPA Method 26 in appendix A to part 60 of this chapter (for boilers without wet scrubbers) or EPA Method 26A in appendix A to part 60 of this chapter (for boilers with wet scrubbers).

(5) For new boilers and process heaters in any of the limited use subcategories and new boilers and process heaters in any of the large subcategories with heat input capacities greater than 10 MMBtu/hr but less than 100 MMBtu/hr, conduct initial and annual stack tests to determine compliance with the CO work practice limit using EPA Method 10, 10A, or 10B in appendix A to part 60 of this chapter.

(6) Use EPA Method 19 in appendix A to part 60 of this chapter to convert measured concentration values to pounds per million British thermal units (MMBtu) values.

(7) For new units in any of the liquid fuel subcategories that do not burn residual oil, instead of conducting an initial and annual compliance test you may submit a signed statement in the Notification of Compliance Status report that indicates that you only burn liquid fossil fuels other than residual oil.

(8) For affected sources that choose to meet the emission limits based on fuel analysis, conduct the fuel analysis using method ASTM D5865–01ae1 or ASTM E711–87 to determine heat content; ASTM D3684–01 (for coal), SW–846–7471A (for solid samples) or SW–846–7470A (for liquid samples) to determine mercury levels; SW–846–6010B or ASTM D3683–94 (for coal) or ASTM E885–88 (for biomass) to determine total selected metals concentration; SW–846–9250 or ASTM E776–87 (for biomass) to determine chlorine concentration; and ASTM D3173 or ASTM E871 to determine moisture content.

As part of the initial compliance demonstration, you must monitor specified operating parameters during the initial performance tests that demonstrate compliance with the PM (or metals), mercury, and HCl emission limits. You must calculate the average parameter values measured during each test run over the 3-run performance test. The minimum or maximum of the three average values (depending on the parameter measured) for each applicable parameter establishes the site-specific operating limit. The applicable operating parameters for which operating limits must be established are based on the emissions limits applicable to your unit as well as the types of add-on controls on the unit. A summary of the operating limits that must be established for the various types of controls are as follows:

(1) For boilers and process heaters without wet scrubbers that must comply with the mercury emission limit and either a PM emission limit or a total selected metals emission limit, you must meet an opacity limit of 20 percent for existing sources (based on 6-minute averages), except for one 6-minute period per hour of not more than 27 percent, or 10 percent for new sources (based on 1-hour block averages). Or, if the unit is controlled with a fabric filter, instead of meeting an opacity operating limit, you may elect to operate the fabric filter using a bag leak detection system such that corrective actions are initiated within 1 hour of a bag leak detection system alarm and you operate and maintain the fabric filter such that the alarm is not engaged for more than 5 percent of the total operating time in a 6-month reporting period.

(2) For boilers and process heaters without wet or dry scrubbers that must comply with an HCl emission limit, you must determine the average chloride content level in the input fuel(s) during the HCl performance test. This is your maximum chloride input operating limit.

(3) For boilers and process heaters with wet scrubbers that must comply with a mercury, PM (or total selected metals) and/or an HCl emission limit, you must measure pressure drop and liquid flow rate of the scrubber during the performance test and calculate the average value for each test run. The minimum test run average establishes your site-specific pressure drop and liquid flow rate operating levels. If different average parameter levels are measured during the mercury, PM (or metals) and HCl tests, the highest of the minimum test run average values establishes your site-specific operating limit. If you are complying with an HCl emission limit, you must measure pH during the performance test for HCl and determine the average for each test run and the minimum value for the performance test. This establishes your minimum pH operating limit.

(4) For boilers and process heaters with dry scrubbers that must comply with an HCl emission limit, you must measure the sorbent injection rate during the performance test for mercury and HCl and calculate the average for each test run. The minimum test run average during the performance test establishes your site-specific minimum sorbent injection rate operating limit.

(5) For boilers and process heaters with fabric filters in combination with wet scrubbers that must comply with a mercury emission limit, PM (or total selected metals) emission limit and/or an HCl emission limit, you must measure the pH, pressure drop, and liquid flowrate of the wet scrubber during the performance test and calculate the average value for each test run. The minimum test run average establishes your site-specific pH, pressure drop, and liquid flowrate operating limits for the wet scrubber. Furthermore, the fabric filter must be operated such that the bag leak detection system alarm does not sound more than 5 percent of the operating time during any 6-month period.

(6) For boilers and process heaters with electrostatic precipitators (ESP) in combination with wet scrubbers that must comply with a mercury, PM (or total selected metals) and/or an HCl emission limit, you must measure the pH, pressure drop, and liquid flow rate of the wet scrubber during the HCl performance test, and you must measure the voltage and secondary current of the ESP collection plates or total power input during the mercury and PM (or metals) performance test. Calculate the average value of these parameters for each test run. The minimum test run averages establish your site-specific minimum pH, pressure drop, and liquid flowrate operating limit for the wet scrubber and the minimum voltage and current operating limits for the ESP.

(7) For boilers and process heaters that choose to comply with the alternative total selected metals emission limit instead of PM, you must determine the total selected metals content of the inlet fuels that were burned during the total selected metals performance test. This value is your maximum fuel inlet metals content operating limit.

(8) For boilers and process heaters that burn a mixture of multiple fuels, you must determine the mercury content of the inlet fuels that were burned during the mercury performance test. This value is your maximum fuel inlet mercury operating limit. Units burning only a single fuel type (not including start-up fuels) do not need to determine, by fuel analysis, the fuel inlet operating limit when conducting performance tests.

(9) For new boilers and process heaters in any of the large subcategories and with heat input capacities greater or equal to 100 MMBtu/hr, you must monitor CO to demonstrate that average CO emissions, on a 30-day rolling average, are at or below an exhaust concentration of 400 parts per million (ppm) by volume on a dry basis corrected to 3 percent oxygen for units in the liquid subcategories and corrected to 7 percent for units in the solid subcategories. For new boilers and process heaters in any of the limited use subcategories or with heat input capacities less than 100 MMBtu/hr, you must conduct initial test of CO emissions to demonstrate compliance with the CO work practice limit.

The final rule also provides you another compliance alternative. You may demonstrate compliance by emissions averaging for existing large solid fuel boilers in States that choose to allow emissions averaging in their operating permit program.

### *G. What Are the Continuous Compliance Requirements?*

To demonstrate continuous compliance with the emission limitations, you must monitor and comply with the applicable site-specific operating limits established during the performance tests or fuel analysis. Upon detecting an excursion or exceedance, you must restore operation of the unit to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance. Such actions may include initial inspections and evaluation, recording that operations returned to normal without operator action, or any necessary follow-up actions to return operation to below the work practice standard.

(1) For boilers and process heaters without wet scrubbers that must comply with a mercury emission limit and either a PM emission limit or a total selected metals emission limit, you must continuously monitor opacity and maintain the opacity at or below the maximum opacity operating limit for new and existing sources. Or, if the unit is controlled with a fabric filter, instead of continuous monitoring opacity, the fabric filter may be continuously operated such that the bag leak detection system alarm does not sound

more than 5 percent of the operating time during any 6-month period.

(2) For boilers and process heaters without wet or dry scrubbers that must comply with an HCl emission limit, you must maintain monthly records of fuel use that demonstrate that you have burned no new fuel types or new mixtures such that you have maintained the fuel HCl content level at or below your site-specific maximum HCl input operating limit. If you plan to burn a new fuel type or a new mixture than what was burned during the initial performance test, then you must re-calculate the maximum HCl input anticipated from the new fuels based on supplier data or your own fuel analysis. If the results of re-calculating the HCl input exceeds the average HCl content level established during the initial test, then you must conduct a new performance test to demonstrate continuous compliance with the HCl emission limit.

(3) For boilers and process heaters with wet scrubbers that must comply with a mercury, PM (or total selected metals) and/or an HCl emission limit, you must monitor pressure drop and liquid flow rate of the scrubber and maintain the 3-hour block averages at or above the operating limits established during the performance test. You must monitor the pH of the scrubber and maintain the 3-hour block average at or above the operating limit established during the performance test to demonstrate continuous compliance with the HCl emission limits.

(4) For boilers and process heaters with dry scrubbers that must comply with a PM (or total selected metals) or mercury emission limit, and/or an HCl emission limit, you must continuously monitor the sorbent injection rate and maintain it at or above the operating limits established during the HCl performance test.

(5) For boilers and process heaters with fabric filters in combination with wet scrubbers, you must monitor the pH, pressure drop, and liquid flow rate of the wet scrubber and maintain the levels at or above the operating limits established during the HCl performance test. You must also maintain the operation of the fabric filter such that the bag leak detection system alarm does not sound more than 5 percent of the operating time during any 6-month period.

(6) For boilers and process heaters with ESP in combination with wet scrubbers that must comply with a mercury, PM and/or an HCl emission limit, you must monitor the pH, pressure drop, and liquid flow rate of the wet scrubber and maintain the 3-hour block averages at or above the operating limits established during the HCl performance test. Also, you must monitor the voltage and secondary current of the ESP collection plates or total power input and maintain the 3-hour block averages at or above the operating limits established during the mercury or PM (or metals) performance test.

(7) For boilers and process heaters that choose to comply with the alternative total selected metals limit instead of PM emission limit, you must maintain monthly fuel records that demonstrate that you burned no new fuel type or new mixtures such that the total selected metals content of the inlet fuel was maintained at or below your maximum fuel inlet metals content operating limit set during the metals performance test. If you plan to burn a new fuel type or new mixture, then you must re-calculate the maximum metals input anticipated from the new fuels based on supplier data or own fuel analysis. If the results of re-calculating the metals input exceeds the average metals content level established during the initial test, then you must conduct a new performance test to demonstrate continuous compliance with the alternate selected metals emission limit.

(8) For boilers and process heaters that must comply with the mercury emission limit, you must maintain monthly fuel records that demonstrate that you burned no new fuel type or new mixture such that the total selected mercury content of the inlet fuel was maintained at or below your maximum fuel inlet metals content operating limit set during the mercury performance test. If you plan to burn a new fuel type or new mixture than what was burned during the initial performance test, then you must re-calculate the maximum mercury input anticipated from the new fuels based on supplier data or own fuel analysis. If the results of re-calculating the mercury input exceeds the average mercury content level established during the initial test, then you must conduct a new performance test to demonstrate continuous compliance with the mercury emission limit.

(9) For boilers and process heaters that choose to comply with any emission limit based on fuel analysis, you must maintain monthly fuel records to demonstrate that the content of fuel is maintained below the appropriate applicable emission limit.

(10) For new boilers and process heaters in any of the large subcategories with heat input capacities greater or equal to 100 MMBtu/hr, you must continuously monitor CO and maintain the 30-day rolling average CO emissions at or below 400 ppm by volume on a dry basis (corrected to 3 percent oxygen for units in the liquid or gaseous subcategories, and 7 percent for units in the solid fuel subcategories) to demonstrate compliance with the work practice standards at all times except during startup, shutdown, and malfunction and when the unit is operating less than 50 percent of the rated capacity.

If a control device other than the ones specified in this section is used to comply with the final rule, you must establish site-specific operating limits and establish appropriate continuous monitoring requirements, as approved by the EPA Administrator.

If you choose to comply using emissions averaging, you must demonstrate on a monthly basis that mercury, metals, PM, and HCl emission limits can be met over a 12-month period.

### *H. What Are the Notification, Recordkeeping and Reporting Requirements?*

If your boiler or process heater is in the existing large gaseous fuel subcategory, or existing limited use gaseous fuel subcategory, or existing large liquid fuel subcategory, or existing limited use liquid fuel subcategory, or a new small liquid fuel unit that only burn gaseous fuels or distillate oil, you only have to submit the initial notification report. If your boiler or process heater is in the existing small gaseous, liquid, or solid fuel subcategories or new small gaseous fuel subcategory, you are not required to keep any records or submit any reports.

If your boiler or process heater is in any other subcategory, then you must keep the following records:

(1) All reports and notifications submitted to comply with the final rule.

(2) Continuous monitoring data as required in the final rule.

(3) Each instance in which you did not meet each emission limit work practice and operating limit, including periods of startup, shutdown, and malfunction (*i.e.*, deviations from the final rule).

(4) Monthly hours of operation by each source that is in a limited use subcategory.

(5) Monthly fuel use by each boilers and process heaters subject to an emission limit including a description of the type(s) of fuel(s) burned, amount of each fuel type burned, and units of measure.

(6) Calculations and supporting information of chloride fuel input, as required in the final rule.

(7) Calculations and supporting information of total selected metals and mercury fuel input, as required in the final rule, if applicable.

(8) A copy of the results of all performance tests, fuel analysis, opacity observations, performance evaluations, or other compliance demonstrations conducted to demonstrate initial or continuous compliance with the final rule.

(9) A copy of any federally enforceable permit that limits the annual capacity factor of the source to less than or equal to 10 percent.

(10) A copy of your site-specific startup, shutdown, and malfunction plan.

(11) A copy of your site-specific monitoring plan developed for the final rule, if applicable.

(12) A copy of your site-specific fuel analysis plan developed for the final rule, if applicable.

(13) A copy of the emissions averaging plan, if applicable.

You must submit the following reports and notifications:

(1) Notifications required by the General Provisions.

(2) Initial Notification no later than 120 calendar days after you become subject to the final rule.

(3) Notification of Intent to conduct performance tests and/or compliance demonstration at least 30 calendar days before the performance test and/or compliance demonstration is scheduled.

(4) Notification of Compliance Status 60 calendar days following completion of the performance test and/or compliance demonstration.

(5) Notification of intent to demonstrate compliance by emissions averaging.

(6) Notification of intent to demonstrate eligibility for either health-based compliance alternative.

(7) Compliance reports semi-annually.

### *I. What Are the Health-Based Compliance Alternatives, and How Do I Demonstrate Eligibility?*

#### HCl Compliance Alternative

As an alternative to the requirement for each large solid fuel-fired boiler to demonstrate compliance with the HCl emission limit in the final rule, you may demonstrate compliance with a health-based HCl equivalent allowable emission limit.

The procedures for demonstrating eligibility for the HCl compliance alternative (as outlined in appendix A of the final rule) are:

(1) You must include in your demonstration every emission point covered under the final rule.

(2) You must conduct HCl and chlorine emissions tests for every emission point covered under the final rule.

(3) You must determine the total maximum hourly mass HCl-equivalent emission rate for your affected source by summing the maximum hourly emission rates of HCl and chlorine for each of the affected units at your facility covered under the final rule.

(4) Use the look-up table in the appendix A of the final rule to determine if your facility is in compliance with the health-based HCl-equivalent emission limit.

(5) Select the maximum allowable HCl-equivalent emission rate from the look-up table in appendix A of the final rule for your affected source using the average stack height of your emission units covered under the final rule as your stack height and the minimum distance between any affected emission point and the property boundary as your property boundary.

(6) Your facility is in compliance if your maximum HCl-equivalent emission rate does not exceed the value specified in the look-up table in appendix A of the final rule.

(7) As an alternative to using the look-up table, you may conduct a site-specific compliance demonstration (as outlined in appendix A of the final rule) which demonstrates that the subpart DDDDD units at your facility are not expected to cause an individual chronic inhalation exposure from HCl and chlorine which can exceed a Hazard Index (HI) value of 1.0.

#### Total Selected Metals Compliance Alternative

In lieu of complying with the emission standard for total selected metals (TSM) in the final rule based on the sum of emissions for the eight selected metals, you may demonstrate eligibility for complying with the TSM standard based on excluding manganese emissions from the summation of TSM emissions for the affected source unit(s).

The procedures for demonstrating eligibility for the TSM compliance alternative (as outlined in appendix A of the final rule) are:

(1) You must include in your demonstration every emission point covered under the final rule that emits manganese.

(2) You must conduct manganese emissions tests for every emission point covered under the final rule that emits manganese.

(3) You must determine the total maximum hourly manganese emission rate from your affected source by summing the maximum hourly manganese emission rates for each of the affected units at your facility covered under the final rule.

(4) Use the look-up table in appendix A of the final rule to determine if your facility is eligible for complying with the alternative TSM limit based on the sum of emissions for seven metals (excluding manganese) for the affected source units.

(5) Select the maximum allowable manganese emission rate from the look-up table in appendix A of the final rule for your affected source using the average stack height of your emission units covered under the final rule as your stack height and the minimum distance between any of those emission points and the property boundary as your property boundary.

(6) Your facility is eligible if your maximum manganese emission rate does not exceed the value specified in the look-up table in appendix A of the final rule.

(7) As an alternative to using look-up table to determine if your facility is eligible for the TSM compliance alternative, you may conduct a site-specific compliance demonstration (as outlined in appendix A of the final rule) which demonstrates that the subpart DDDDD units at your facility are not expected to cause an individual chronic inhalation exposure from manganese which can exceed a Hazard Quotient (HQ) value of 1.0.

If you elect to demonstrate eligibility for either of the health-based compliance alternatives, you must submit certified documentation supporting compliance with the procedures at least 1 year before the compliance date.

You must submit supporting documentation including documentation of all maximum capacities, existing control devices used to reduce emissions, stack parameters, and property boundary distances to each affected source of HCl-equivalent and/or manganese emissions.

You must keep records of the information used in developing the eligibility demonstration for your affected source.

To be eligible for either health-based compliance alternative, the parameters that defined your affected source as eligible for the health-based compliance alternatives (including, but not limited to, fuel type, type of control devices, process parameters reflecting the emission rates used for your eligibility demonstration) must be incorporated as Federally enforceable limits into your title V permit. If you do not meet these criteria, then your affected source is subject to the applicable emission limits, operating limits, and work practice standards in the final rule.

If you intend to change key parameters (including distance of stack to the property boundary) that may result in lower allowable health-based emission limits, you must recalculate the limits under the provisions of this section, and submit documentation supporting the revised limits prior to initiating the change to the key parameter.

If you intend to install a new solid fuel-fired boiler or process heater or change any existing emissions controls that may result in increasing HCl-equivalent and/or manganese emissions, you must recalculate the total maximum hourly HCl-equivalent and/or manganese emission rate from your affected source, and submit certified documentation supporting continued eligibility under the revised information prior to initiating the new installation or change to the emissions controls.

## III. What Are the Significant Changes Since Proposal?

### *A. Definition of Affected Source*

The definition of affected source in § 63.7490 has been revised to be: (1) The collection of all existing industrial, commercial, or institutional boilers or process heaters within a subcategory located at a major source; and/or (2) each new or reconstructed industrial, commercial, or institutional boiler or process heater located at a major source.

### *B. Sources Not Covered by the NESHAP*

The applicability section of the final rule (§ 63.7490(c)) has been written to clarify that the following are not subject to the final rule: Blast furnace stoves, any boiler or process heater specifically listed as an affected source in another MACT standard, temporary boilers, and blast furnace gas fuel-fired boilers and process heaters.

### *C. Emission Limits*

The emission limit for mercury in the existing large solid fuel subcategories has been written as 0.000009 lb/MMBtu (from 0.000007 lb/MMBtu at proposal).

### *D. Definitions Added or Revised*

The EPA has written the definitions of large, limited use, and small gaseous subcategories to include gaseous fuel-fired boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply emergencies.

The final rule also includes a definition of fuel type which is used in the fuel analysis compliance options. Fuel type means each category of fuels that share a common name of classification. Examples include, but are not limited to: bituminous coal, subbituminous coal, lignite, anthracite, biomass, construction/demolition material, salt water laden wood, creosote treated wood, tires, and residual oil. Individual fuel types received from different suppliers are not considered new fuel types except for construction/demolition material.

Construction/demolition material means waste building material that result from the construction or demolition operations on houses and commercial and industrial buildings.

Unadulterated wood, component of biomass, means wood or wood products that have not been painted, pigment-stained, or pressure treated with compounds such as chromate copper arsenate, pentachlorophenol, and creosote. Plywood, particle board, oriented strand board, and other types of wood products bound by glues and resins are included in this definition.

We have included a definition for temporary boiler to mean any gaseous or liquid fuel-fired boiler that is designed, and is capable of, being carried or moved from one location to another. A temporary boiler that remains at a location for more than 180 consecutive days is no longer considered to be a temporary boiler. Any temporary boiler that replaces a temporary boiler at a location and is intended to perform the same or similar function will be included in calculating the consecutive time period.

The final rule also contains a definition written for waste heat boiler that identifies waste heat boilers incorporating duct or supplemental burners that are designed to supply 50 percent or more of the total rated heat input capacity of the waste heat boiler as not being waste heat boilers, but are considered boilers and subject to the final rule.

### *E. Requirements for Sources in Subcategories Without Emission Limits or Work Practice Requirements*

In the final rule, we have clarified that sources in the existing large and limited use gaseous fuel subcategories, existing large and limited use liquid fuel subcategories, and new small liquid fuel subcategory that burn only distillate oil are only subject to the initial notification requirements in § 63.9(b) of subpart A of this part and are not required to submit as startup, shutdown, and malfunction (SSM) plan as part of their initial notification. We have written the final rule to state that sources in the existing small gaseous fuel, liquid fuel, and solid fuel subcategories and in the new small gaseous fuel subcategory are not subject to any requirements in the final rule or of subpart A of this part.

### *F. Carbon Monoxide Work Practice Emission Levels and Requirements*

The final rule provides revisions to the CO work practice emission levels. For new sources in the solid fuel subcategory, the work practice standard has been written to be corrected to 7 percent oxygen rather than 3 percent. Units in the gaseous and liquid fuel subcategories still have to correct to 3 percent oxygen.

The final rule also allows sources with heat input capacities greater than 10 MMBtu/hr but less than 100 MMBtu/hr to conduct initial and annual compliance tests to demonstrate compliance with the CO limit. Sources greater than 100 MMBtu/hr must still demonstrate compliance using CO continuous emission monitors (CEMS).

The final rule also does not allow you to calculate data average using data recorded during periods where your boiler or process heater is operating at less than 50 percent of its rated capacity, monitoring malfunctions, associated repairs, out-of-control periods, or required quality assurance or control activities. You must use all data collected during all other periods in assessing compliance.

### *G. Fuel Analysis Option*

We have clarified the fuel analysis options in the final rule. You are not required to conduct performance tests for hydrogen chloride, mercury, or total selected metals if you demonstrate compliance with the hydrogen chloride, mercury, or total selected metals limits based on the fuel pollutant content. Your operating limit is then the emission limit of the applicable pollutant. You are not required to conduct emission tests.

If you demonstrate compliance with the HCl, mercury, or TSM limit by performance tests, then your operating limits are the operating limits of the control device (if used) and the fuel pollutant content of the fuel type/mixture burned. Units burning multiple fuel types are required to determine by fuel analysis, the fuel pollutant content of the fuel/mixture burned during the performance test.

The final rule specifies the testing and initial and continuous compliance requirements to be used when complying with the fuel analysis options. Fuel analysis tests for total chloride, gross calorific value, mercury, metal analysis, sample collection, and sample preparation are included in the final rule.

We have written the requirement to remove the need for conducting additional tests if you receive fuel from a new supplier. You are required to conduct another performance test, if you demonstrated compliance through performance testing, only when you burn a new fuel type or mixture and the results of recalculating the fuel pollutant content are higher than the level established during the initial performance test.

### *H. Emissions Averaging*

We have included a compliance alternative in the final rule to allow emissions averaging between existing large solid fuel boilers. Compliance must be demonstrated on a 12-month rolling average basis, determined at the end of every month. If you elect to comply with the emissions averaging compliance alternative, you must use equations provided in the final rule to demonstrate that particulate matter or TSM, HCl, or mercury from all applicable units do not exceed the emission limits specified in the final rule. If you use this option, you must also develop and submit an implementation plan no later than 6 months before the date that the facility intends to demonstrate compliance.

### *I. Opacity Limit*

At proposal, we required sources meeting the PM and mercury limits to determine site-specific opacity operating limits based on levels during the initial performance test. To demonstrate continuous compliance with the opacity limit, the opacity operating limits have been established to be 20 percent (based on 6-minute averages) except for one 6-minute period per hour of not more than 27 percent for existing sources and 10 percent (based on 1-hour block averages) for new sources.

### *J. Operating Limit Determination*

The final rule defines maximum and minimum operating parameters that must be met. For sources complying with the alternative opacity requirement of establishing opacity limits during the initial performance test, the maximum opacity operating limit is 110 percent of the highest test-run average opacity measured according to the final rule during the most recent performance test demonstrating compliance with the applicable emission limit. For sources meeting the standards using scrubbers or ESP, the minimum pressure drop, scrubber effluent pH, scrubber flow rate, sorbent flow rate, voltage or amperage means 90 percent of the lowest test run average pressure drop, scrubber effluent pH, scrubber flow rate, sorbent flow rate, voltage or amperage measured according to the most recent performance test demonstrating compliance with the applicable emission limits.

The final rule clarifies that operation above the established maximum or below the established minimum operating parameters constitute a deviation of established operating parameters.

### *K. Revision of Compliance Dates*

In § 63.7510, we have also written the date by which you have to complete a compliance demonstration to be 180 days after the compliance date instead of at the compliance date.

## IV. What Are the Responses to Significant Comments?

We received 218 public comment letters on the proposed rule. Complete summaries of all the comments and responses are found in the Response-to-Comments document (see **SUPPLEMENTARY INFORMATION** section).

### *A. Applicability*

*Comment:* Many commenters requested that EPA exempt units that are not subject to emission limits or work practice requirements from monitoring, recordkeeping, and reporting requirements.

*Response:* Sources in subcategories that do not have any emission limitations and work practices are not required to keep records or reports other than the initial notification. This is appropriate because no reports other than the initial notification would apply to these units. The SSM plan is not necessary nor required for these units because § 63.6(e)(3) of subpart A of this part requires an affected source to develop an SSM plan for control equipment used to comply with the relevant standard. The proposed rule was not intended to require monitoring, recordkeeping, and reporting (including startup, shutdown, and malfunction plans), other than the initial notification for sources not subject to an emission limit. We have clarified this decision in the final rule. We have also determined that existing small units and new small gaseous fuel units, which are not subject to emission limits or work practices in this standard, and which are also not subject to such requirements in any other Federal regulation, should also not have to provide an initial notification. These small sources are generally gas-fired and since they have minimal emissions, they are usually considered as insignificant emission units by State permitting agencies.

*Comment:* Several commenters requested that EPA specifically exclude portable/transportable units from the final rule. The commenters stated that facilities periodically use these units to supply or supplement other site steam supplies when there is a mechanical problem that takes a unit out of service or during planned outages. The commenters added that because they are used on a limited basis, portable units are not fully integrated with site control systems and most portable/transportable units are owned by a rental company and may not be operated by the facility owner/operator.

*Response:* We agree with the commenters that temporary/portable units are used only on a limited basis and are not integrated into a facility's control system. These units are gas or oil fired units. Units in the existing gaseous or liquid subcategories are not subject to emission limits or work practice standards. Consequently, we have decided that temporary/portable units are not subject to the final rule. We have added a definition for temporary boiler to mean any gaseous or liquid fuel-fired boiler that is designed, and is capable of, being carried or moved from one location to another. A temporary boiler that remains at a location for more than 180 consecutive days is no longer considered to be a temporary boiler. Any temporary boiler that replaces a temporary boiler at a location and is intended to perform the same or similar function will be included in calculating the consecutive time period. We chose the 180-day time frame because that is the length of time a new source has after startup to conduct the initial performance test.

*Comment:* Several commenters requested EPA provide a lower size cut-off for the small unit subcategory. Several commenters argued that the benefits from requiring smaller units to install controls would be minimal given the overall monitoring, recordkeeping, and reporting burden. Several commenters also requested lower size cutoffs to make the final rule similar to others established by EPA (*e.g.,* NSPS Nitrogen Oxide ($NO_X$) SIP Call). Several commenters noted several recent court decisions in which the court has decided that a *de minimis* exemption is appropriate since the regulation of small sources would yield a gain of trivial or no value yet would impose significant regulatory burden. A wide range of lower size cutoffs were suggested. However, one commenter said that EPA should not develop *de minimis* exemptions. The commenter noted that *de minimis* exemptions do not spare EPA's resources for use on other purposes and are not justified by reductions in industry burden or inconvenience. The commenter noted that EPA did not establish any administrative record justifying the *de minimis* exemption.

*Response:* We have reviewed the commenters arguments and all the data provided in the comment letters. There is no justification for developing a lower size cut-off or *de minimis* level. We would also note the designation of large and small subcategories was not based solely on size of the unit. Large and small subcategories were developed because small units less than 10 MMBtu/hr heat input typically use a combustor design that is not common in larger units. Large boilers generally use the watertube combustor design. The design of the boiler or process heater will influence the completeness of the combustion process which will influence the formation of organic HAP emissions. Additionally, the vast majority of small units use natural gas as fuel. The EPA chose to develop large and small subcategories to account for these differences and their affect on the type of emissions. The cut-off between the large and small subcategories of 10 MMBtu/hr was based on typical sizes for fire tube units, and also when considering cut-offs in State and Federal rules. Lastly, we would like to note that the final rule does not impose any requirements for existing units in any of the small subcategories.

*Comment:* Many commenters asked EPA to clarify which sources are not covered by the final rule.

*Response:* We have included an extensive list of sources that are not subject to the final rule. The final rule clarifies that boilers and process heaters that are included as part of the affected source in any other NESHAP are not subject to the NESHAP for industrial boilers and process heaters. However, we do not exclude boilers and process heaters that are used as control devices unless they are specifically considered part of any other NESHAP's definition of affected source. Incinerators, thermal oxidizers, and flares do not generally fall under the definition of a boiler or process heater and would not be subject to the final rule. The final rule excludes waste heat boilers and waste heat boilers with supplemental firing, as long as the supplemental firing does not provide more than 50 percent of the waste heat boiler's heat input. If your waste heat boiler does receive 50 percent of its total heat input from supplemental firing, it would be subject to the NESHAP for industrial boilers unless it is subject to any other NESHAP. We specifically exclude comfort heaters from the final rule. However, this exclusion does not include boilers used to make steam or heated water for comfort heat. If your boiler meets the definition of a hot water heater, then it would not be subject to the final rule. However, if the temperature, pressure, or capacity specifications of your boiler exceed the criteria specified for hot water heaters, then your boiler would be subject to the final rule. We recognize the unique properties of blast furnace gas having high CO concentrations and none to almost no organic compounds. Consequently, we agree that for these sources CO is not a surrogate for organic HAP emissions since CO is the primary component of blast furnace gas and virtually no organic HAP are generated in its combustion. As a result, we exclude from the final rule units that receive 90 percent or more of their total heat input from blast furnace gas. In addition, research and development (R&D) operations are not subject to the final rule. However, units that only provide steam to a process or for heating at a research and development facility are still subject to the final rule. This should address the commenters' concern over overlapping applicability.

*Comment:* Several commenters suggested that EPA revise the proposed definition of affected source to be consistent with the definition of affected source in the General Provisions. The definition in the rule as proposed is much more narrow than that in the General Provisions, even though the General Provisions states that each standard will redefine affected source based on published justification as to why the definition would result in significant administration, practical or implementation problems. The commenters argued that EPA failed to provide justification for the proposed definition of affected source, which is narrower than the definition of affected source in the General Provisions.

*Response:* We agree with the commenters and in the final rule have incorporated the broader definition of affected source from the revised General Provisions. The General Provisions define the affected source as ''the collection of equipment, activities, or both within a single contiguous area and under common control that is included in a section 112(c) source category or subcategory * * *'' Therefore, the definition of existing affected source in the final rule is the collection of existing industrial, commercial, or institutional boilers and process heaters within a subcategory located at a major source of HAP emissions.

### *B. Format*

*Comment:* Several commenters opposed using one or more surrogates for the HAP regulated. Some commenters stated that EPA must set emission standards for each HAP emitted by this category. One commenter explained that the use of surrogates is acceptable if: (1) The surrogates reflect the actual emissions of the represented pollutants, (2) the emission limit set for the surrogate is consistent with the emission limit calculated for the represented pollutants, and (3) the surrogates have substantially the same properties as the represented pollutants and is controlled by the same mechanism. Based on these criteria, the commenter argued that EPA's selection of surrogates is inadequate. One commenter specifically contended that CO is not an adequate surrogate for dioxin because dioxin emissions are affected by the temperature of the emissions, how quickly the temperature is lowered, and the levels of chlorine in the materials that are being combusted and control devices. Other commenters supported the use of surrogates to represent the HAP list.

*Response:* As discussed in the proposal preamble, the use of surrogates for the HAP regulated is appropriate. Because of the large number of HAP potentially present, the disparity in the quality and quantity of the emissions information available, particularly for different fuel types, we chose to group HAP into four categories: Mercury, non-mercury metallic HAP, inorganic HAP, and organic HAP. In general, the pollutants within each group have similar characteristics and can be controlled with the same techniques. We then chose compounds that could be used as surrogates for all the compounds in each pollutant category. We have used surrogates in previous NESHAP as a technique to reduce the performance testing costs, and thus the use of surrogates is appropriate in the final rule.

For inorganic HAP, we chose to use HCl as a surrogate. The emissions test information available to us indicated that the primary inorganic HAP emitted from boilers and process heaters is HCl. Much smaller amounts of hydrogen fluoride and chlorine are emitted. Control technologies that would reduce HCl would also control other inorganic HAP. Additionally, we had limited emissions information for other inorganic HAP. By focusing on HCl, we have achieved control of the largest emitted and most widely emitted HAP, and control of HCl would also constitute control of other inorganic HAP.

For non-mercury metallic HAP, we chose to use PM as a surrogate. Most, if not all, non-mercury metallic HAP emitted from combustion sources will appear on the flue gas fly-ash. Therefore, the same control technology that would be used to control fly-ash PM will control non-mercury metallic HAP. A review of data in the emission database for PM control devices having both inlet and outlet emissions results shows control efficiencies for each non-mercury metallic HAP similar to PM. Particulate matter was also chosen instead of a specific metallic HAP because all fuels do not emit the same type and amount of metallic HAP, but most generally emit PM that includes some amount and combination of metallic HAP. We maintain that particulate matter reflects the emissions of non-mercury metallic HAP as these compounds usually comprise a percentage of the emitted particulate matter. Since the NESHAP program is technology-based, the technologies that have been developed and implemented to control particulate matter, also control non-mercury metallic HAP. Furthermore, since non-mercury metallic HAP is a component of particulate matter, we can use particulate matter as a surrogate for the purposes of the final rule.

While we did use PM as a surrogate for non-mercury metallic HAP, we also provided an alternative total selected metals emission limit based on the sum of the emissions of the eight most common and largest emitted metallic HAP compounds from boilers and process heaters. Again, a total selected metals number was used instead of limits for each individual metallic HAP because sufficient information was not available for each metallic HAP for every fuel type. However, a total metals number could be calculated for every fuel type.

We realize that mercury emissions can exist in different forms depending on combustion conditions and concentrations of other compounds. That is why we have mercury as a separate pollutant category in the final rule and do not provide for a surrogate.

For organic HAP, we chose to use CO as a surrogate to represent the variety of organic compounds emitted from the various fuels burned. Both organic HAP and CO emissions are the result of incomplete combustion of the fuel. Because CO is a good indicator of incomplete combustion, there is a direct correlation between CO emissions and minimizing organic HAP emissions. The extent to which CO and HAP emissions are related can also depend on site-specific operating conditions for each boiler or process heater. This site-specific nature may result in various degrees of correlation between CO and organic HAP emissions, but it is proven that reductions in CO emissions result in a reduction of organic HAP emissions. The control methods for both CO and organic HAP are the same, *i.e.*, complete combustion. This result would not have been different if MACT floor analyses were conducted for specific organic HAP or for a surrogate compound such as CO. For boilers and process heaters, we have determined that CO is a reasonable indicator of incomplete combustion. Also, we did not set emission limits for each specific organic HAP because we lacked sufficient information for many of the organic HAP for all the fuels combusted. We acknowledge that there are many factors that affect the formation of dioxin, but we also recognize that dioxin can be formed in both the combustion unit and downstream in the associated PM control device. Minimizing organic HAP emissions can limit the formation of dioxin in the combustion unit. We reviewed all the good combustion practice (GCP) information available in the boiler population database and determined that no floor level of control exists, except for limiting CO emissions, such that GCP could be incorporated into the standard. One control technique, controlling inlet temperature to the PM control device, that has demonstrated controlling downstream formation of dioxins in other source categories (*e.g.,* municipal waste combustors) was analyzed for industrial boilers. In all cases, no increase in dioxins emissions were indicated across the PM control device even at high inlet temperatures. However, we requested comment on controls that would achieve reductions of organic HAP, including any additional data that might be available. The EPA did not receive any additional supporting information or data. Additionally, more stringent options beyond the floor level of control were evaluated, but were determined to be too costly and emissions reductions associated with the options could not be evaluated because no information was available that indicated a relationship between the GCP and emission reduction of organics (including dioxin).

### *C. Compliance Schedule*

*Comment:* Many commenters requested that EPA provide an additional year to comply with the final rule. Commenters explained that the time lines associated with permitting, capital appropriation, project bid, and construction activities are significant and that the 3-year deadline would not provide adequate time for the estimated 3,730 existing units at affected sources to be retrofitted as necessary to meet the new MACT standards. The commenters added that sources subject to the final rule would also be competing with sources that are subject to other combustion rules for the same vendors.

*Response:* The EPA disagrees with the commenters that the 3-year compliance deadline is too short considering the number of sources that will be competing for the resources and materials from engineering consultants, equipment vendors, construction contractors, financial institutions, and other critical suppliers. The EPA recognizes the possibility that these same consultants, vendors, etc., may also be used to comply with the utility MACT standard. However, we know that many sources will not need to install controls. As a result, since not everyone will need more than 3 years to actually install controls, the final rule does not allow an extra year for existing sources to comply with the final rule. Section 112(i)(3)(B) of the CAA allows EPA or the permit authority, on a case-by-case basis, to grant an extension permitting an existing source up to 1 additional year to comply with standards if such additional period is necessary for the installation of controls. This provision is sufficient for those sources where the 3-year deadline would not provide adequate time to retrofit as necessary to comply with the requirements of the standard. We anticipate that a number of units will seek and be granted the 1-year extension since construction of needed control devices could be constrained by the potential impacts on delays in obtaining funding and potential labor and equipment shortages.

### *D. Subcategorization*

*Comment:* Two commenters said that EPA does not have the authority to develop subcategories for the purpose of reducing compliance costs or weakening the standard. The commenters also noted that costs should not be considered in subcategorizing and establishing the MACT floor. One commenter explained that EPA has failed to present a persuasive rationale for the establishment of new or different subcategories, such as a wood-fired unit subcategory and noted that EPA cannot subcategorize based on fuel type, cost, level of emissions reductions, control technology applicability or effectiveness, achievability of emissions reductions, or health risks. The commenter argued that EPA cannot subcategorize to reduce cost because that would change CAA section 112 standards into a cost-benefit program and that is not legally defensible. The commenter noted that the DC Circuit court recently held that, when confronted with the cost argument, costs are not relevant when determining MACT floors.

*Response:* If the commenters are referring to the request for comment regarding further subcategorizations than what was proposed, the EPA agrees that there is no justification for any further subcategories. The final rule maintains the subcategories presented in the proposed rule. If the commenters are referring to subcategories presented in the proposed rule, section 112(d)(1) of the CAA states ''the Administrator may distinguish among classes, types, and sizes of sources within a category or subcategory'' in establishing emission standards. Thus, we have discretion in determining appropriate subcategories based on classes, types, and sizes of sources. We used this discretion in developing subcategories for the industrial, commercial, and institutional boilers and process heaters source category. Through subcategorization, we are able to define subsets of similar emission sources within a source category if differences in emissions characteristics, processes, air pollution control device (APCD) viability, or opportunities for pollution prevention exist within the source category. We first subcategorized boilers and process heaters based on the physical state of the fuel (solid, liquid, or gaseous), which will affect the type of pollutants emitted and controls applicable, and the design and operation of the boiler, which influences the formation of organic HAP emissions. We then further subcategorized boilers and process heaters based on size. Our distinctions are based on technological differences in the equipment. For example, small units are package units typically having capacities less than 10 million Btu per hour heat input and use a combustor design which is not common in large units. A review of the information gathered on boilers also shows that a number of units operate as backup, emergency, or peaking units that operate infrequently. The boiler database indicates that these infrequently operated units typically operate 10 percent of the year or less. These limited use boilers, when called upon to operate, must respond without failure and without lengthy periods of startup. Since their use and operation are different compared to typical industrial, commercial, and institutional boilers, we decided that such limited use units should have their own subcategory.

Neither the subcategories or MACT floor analysis was conducted considering costs, either in the proposed rule or in the final rule.

*Comment:* Many commenters requested EPA to develop a separate subcategory for small municipal electric utilities. Reasons for creating a subcategory for small electrical utility steam generating units included: (1) EPA has authority to establish such a subcategory of sources to be regulated under CAA section 112 and is meant to address control costs and feasibility, (2) past EPA practice supports subcategorization in this instance, (3) differences between municipal utility boilers and non-utility boilers justify subcategorization, and (4) EPA cannot properly account for cost and energy concerns mandated in the MACT standard setting process without subcategorization for municipal utility boilers. The commenters added that the unique physical attributes of municipally-owned utilities, as well as their significant and direct impact on municipal tax base, support a separate subcategorization.

*Response:* The EPA sees no technical or legal justification for creating a separate subcategory for municipal utilities. Boilers at municipal utilities fire the same type of fuels, have the same type of combustor designs, and can use the same type of controls as other units in the large subcategory. Consequently, the subcategories that are in the final rule are the same as at proposal. We would also like to clarify that subcategories were developed based on combustor design and not on industrial sector. Also, had we gone beyond-the-floor, we would have considered cost in the final determination. Since we did not go beyond-the-floor level of control, cost did not play a role in the analysis.

*Comment:* Many commenters requested EPA add a subcategory for medium sized boilers and process heaters.

*Response:* The EPA does not see justification for creating a separate subcategory for medium sized units. The designation of large and small subcategories was not based

*Response:* The EPA does not see justification for creating a separate subcategory for medium sized units. The designation of large and small subcategories was not based solely on size of the unit. Large and small subcategories were developed because small units less than 10 MMBtu/hr heat input typically use a combustor design that is not common in larger units. Large boilers generally use the watertube combustor design. The design of the boiler or process heater will influence the completeness of the combustion process which will influence the formation of organic HAP emissions. The EPA developed large and small subcategories to account for these differences and their affect on the type of emissions. The proposed size break between the large and small subcategories of 10 MMBtu/hr was based on typical sizes for firetube and cast iron units and considering cut-offs in State and Federal permitting requirements and rules. The EPA does not view medium sized boilers as being different than larger boilers. Combustor designs, applicable air pollution control devices, fuels used, and operation are similar for large and medium. While actual pollution controls used and monitoring equipment may be different, the CAA does not allow EPA to subcategorize on these parameters.

Section 112(d)(1) of the CAA allows EPA to distinguish among classes, types, and size in establishing MACT standards. As indicated above, at proposal, the size break selected between large and small units of 10 MMBtu/hr was based on typical sizes for fire tube units and also considering cut-offs in State and Federal permitting requirements and emission rules. Based on comments, we have examined information in the docket regarding the population and characteristics of industrial, commercial, and institutional boilers. It is correct that boilers below 10 MMBtu/hr are generally not required to be permitted and are either firetube or cast iron boilers. Based on review of the thousands of responses received on an information collection request (ICR) conducted during the rulemaking process, it is obvious and appropriate that the distinction between small and large units needs to include size. It is apparent from the ICR responses that facilities know the size of their units but do not generally know the exact type of the units. Many responses indicated that the boiler was both firetube and watertube. Many more responses did not list the boiler type at all. Therefore, the inclusion of size in the definition of small and large subcategories is appropriate.

Based on review of the 1979 EPA document on boiler population and the ICR survey database, the appropriate size break between small and large type units is 10 MMBtu/hr. In the EPA document, 99 percent of the boilers listed as being below 10 MMbtu/hr are either firetube or cast iron. Since these trends are from a 25 year old report, we analyzed our ICR survey database which confirmed these findings.

### *E. MACT Floor*

*Comment*: Several commenters supported EPA's finding that the MACT floor level for existing gas and liquid fuel-fired units is no emissions reductions. Other commenters contended that EPA has legal authority to set the MACT floor as ''no emissions control'' for particular HAP categories. A commenter noted that EPA has a clear statutory obligation to set emission standards for each listed HAP. One commenter specifically challenged EPA's determination that ''no control'' is the MACT floor for organic pollutants. The commenter noted that the U.S. Court of Appeals for the DC Circuit had squarely held, in the National Lime case, that EPA was not allowed to make a ''no control'' determination for a pollutant emitted by a listed category of sources.

*Response*: First, the MACT floor methodology we use is consistent with DC Circuit's holding in the National Lime case. The DC Circuit held that by focusing only on technology EPA ignored the directive in CAA section 112(d)(2) to consider pollution-reducing measures including process changes and substitution of materials.

The EPA has ample legal authority to set the MACT floor at ''no emissions reductions.'' This is because the statute requires EPA to set standards that are duplicable by others. In the National Lime case, the court threw out EPA's determination of a no control floor because it was based only on a control technology approach. The court stated that EPA must look at what the best performers achieve, regardless of how they achieve it. Therefore, our determination that the MACT floor for certain subcategories or HAP is ''no emissions reductions'' is lawful because we determined that the best-performing sources were not achieving emissions reductions through the use of an emission control system and there were no other appropriate methods by which boilers and process heaters could reduce HAP emissions. Furthermore, setting emissions standards on the basis of actual emissions data alone where facilities have no way of controlling their HAP emissions would contravene the plain statutory language as well as Congressional intent that affected sources not be forced to shut down.

The EPA agrees with the commenter that all factors which might control HAP emissions must be considered in making a floor determination for each subcategory. However, EPA disagrees that it must express the floor as a quantitative emission level in those instances where the source on which the floor determination is based has not adopted or implemented any measure that would reduce emissions.

A detailed discussion of the MACT floor methodology is presented in the memorandum ''MACT Floor Analysis for New and Existing Sources in the Industrial, Commercial, and Institutional Boilers and Process Heaters Source Categories'' in the docket. In summary, we considered several approaches to identifying MACT floor for existing industrial, commercial, and institutional boilers and process heaters. Based on recent court decisions, in most cases the most acceptable approach for determining the MACT floor is likely to involve primarily the consideration of available emissions test data. However, after review of the available HAP emission test data, we determined that it was inappropriate to use this MACT floor approach to establish emission limits for boilers and process heaters. The main problem with using only the HAP emissions data is that, based on the test data alone, uncontrolled units (or units with low efficiency add-on controls) were frequently identified as being among the best performing 12 percent of sources in a subcategory, while many units with high efficiency controls were not. However, these uncontrolled or poorly controlled units are not truly among the best controlled units in the category. Rather, the emissions from these units are relatively low because of particular characteristics of the fuel that they burn, that can not reasonably be replicated by other units in the category or subcategory. A review of fuel analyses indicate that the concentration of HAP (metals, HCl, mercury) vary greatly, not only between fuel types, but also within each fuel type. Therefore, a unit without any add-on controls, but burning a fuel containing lower amounts of HAP, can have emission levels that are lower than the emissions from a unit with the best available add-on controls. If only the available HAP emissions data are used, the resulting MACT floor levels would, in most cases, be unachievable for many, if not most, existing units, even those that employ the most effective available emission control technology. Another problem with using only emissions data is that there is very limited or no HAP emissions information available to the Agency for the subcategories. This is consistent with the fact that units in these source categories have not historically been required to test for HAP emissions.

We also considered using HAP emission limits contained in State regulations and permits as a surrogate for actual emission data in order to identify the emissions levels from the best performing units in the category for purposes of establishing MACT standards. However, we found no State regulations or State permits which specifically limit HAP emissions from these sources.

Consequently, we concluded that the most appropriate approach for determining MACT floors for boilers and process heaters is to look at the control options used by the units within each subcategory in order to identify the best performing units. Information was available regarding the emission control options employed by the population of boilers identified by the EPA. We considered several possible control techniques (*i.e.*, factors that influence emissions), including fuel substitution, process changes and work practices, and add-on control technologies.

We first considered whether fuel switching would be an appropriate control option for sources in each subcategory. We considered the feasibility of both fuel switching to other fuels used in the subcategory and to fuels from other subcategories. This consideration included determining whether switching fuels would achieve lower HAP emissions. A second consideration was whether fuel switching could be technically achieved by boilers and process heaters in the subcategory considering the existing design of boilers and process heaters. We also considered the availability of various types of fuel. After considering these factors, we determined that fuel switching was not an appropriate control technology for purposes of determining the MACT floor level of control for any subcategory. This decision was based on the overall effect of fuel switching on HAP emissions, technical and design considerations, and concerns about fuel availability.

We also concluded that process changes or work practices were not appropriate criteria for identifying the MACT floor level of control for units in the boilers and process heaters category. The HAP emissions from boilers and process heaters are either fuel dependent (*i.e.*, mercury, metals, and inorganic HAP) or combustion related (*i.e.*, organic HAP). Fuel dependent HAP are typically controlled by removing them from the flue gas after combustion. Therefore, they are not affected by the operation of the boiler or process heater. Consequently, process changes would be ineffective in reducing these fuel-related HAP emissions.

On the other hand, organic HAP can be formed from incomplete combustion of the fuel. Good combustion practice (GCP), in terms of boilers and process heaters, could be defined as the system design and work practices expected to minimize organic HAP emissions. While few sources in EPA's database specifically reported using good combustion practices, the data that we have suggests that boilers and process heaters within each subcategory might use any of a wide variety of different work practices, depending on the characteristics of the individual unit. The lack of information, and lack of a uniform approach to assuring combustion efficiency, is not surprising given the extreme diversity of boilers and process heaters, and given the fact that no applicable Federal standards, and most applicable State standards, do not include work practice requirements for boilers and process heaters. Even those States that do have such requirements do not require the same work practices. For example, CO emissions are generally a good indicator of incomplete combustion, and, therefore, low CO emissions might reflect good combustion practices. (As discussed in the proposal, CO is considered a surrogate for organic HAP emissions.) Therefore, we considered whether existing CO emission limits might be used to establish good combustion practice standards for boilers and process heaters. We reviewed State regulations applicable to boilers and process heaters, and then for each subcategory we matched the applicability of State CO emission limits with information on the locations and characteristics of the boilers and process heaters in the population database. Ultimately, we found that very few units (less than 6 percent) in any subcategory were subject to CO emission limits. We concluded that this information did not allow EPA to identify a level of performance that was representative of good combustion across the various units in any subcategory. Therefore, we did not establish a CO emission limit, as a surrogate for organic HAP emissions, as a part of the MACT floor for existing units. However, we have considered the appropriateness of such requirements in the context of evaluation possible beyond-the-floor options.

In general, boilers and process heaters are designed for good combustion. Facilities have an economic incentive to ensure that fuel is not wasted, and the combustion device operates properly and is appropriately maintained. In fact, existing boilers and process heaters are used typically as high efficiency control devices to control (reduce) emission streams containing organic HAP compounds from various process operations. Therefore, EPA's inability to establish a combustion practice requirement as part of the MACT floor for existing sources in this category should not reduce the incentive for owners and operators to run their boilers and process heaters at top efficiency.

As a result of the evaluation of the feasibility of establishing emission limits based on control techniques such as fuel switching and good combustion practices, we concluded that add-on control technology should be the primary factor for purposes of identifying the best controlled units within each subcategory of boilers and process heaters. We identified the types of air pollution control techniques currently used. We ranked those controls according to their effectiveness in removing the different HAP categories of pollutants; including metallic HAP and PM, inorganic HAP such as acid gases, mercury, and organic HAP. We then listed all the boilers and process heaters in the population database in order of decreasing control device effectiveness within each subcategory for each pollutant type. Then we identified the top 12 percent of units within each category based on this ranking, and determined what kind of emission control technology, or combination of technologies, the units in the top 12 percent employed. Finally, we looked at the emissions test data from boilers and process heaters that used the same control technology, or technologies, as the units in the top 12 percent to estimate the average emissions limitation achieved by these units.

This approach reasonably ensures that the emission limit selected as the MACT floor adequately represents the average level of control actually achieved by units in the top 12 percent. The analysis of the measured emissions from units representative of the top 12 percent is reasonably designed to provide a meaningful estimate of the average performance, or central tendency, of the best controlled 12 percent of units in a given subcategory. For existing subcategories where less than 12 percent of units in the subcategory use any type of control technology, we looked to see if we could estimate the central tendency of the best controlled units by looking at the unit occupying the median point in the top 12 percent (the unit at the 94th percentile). If the median unit of the top 12 percent is using some control technology, we might use the measured emission performance of that individual unit as the basis for estimating an appropriate average level of control of the top 12 percent. For subcategories where less than 6 percent of the units in a HAP grouping used controls or limited emissions, the median unit for that HAP grouping reflects no emissions reductions. Therefore, in these circumstances, EPA has appropriately established the MACT floor emission levels for these sources as no emission reduction.

*Comment:* Many commenters opposed EPA using emissions data from units in the large subcategory to develop emission limits for units in the small or limited use subcategories. Some commenters stated that it was not appropriate to assume that emissions rates achievable by large units are achievable by small units, even the best controlled units. Other commenters argued that the use of large unit data in MACT determinations for other subcategories would defeat the purpose of the subcategorization and violate the requirements of CAA section 112 because the use of this data does not represent sources in the relevant category or subcategory.

*Response:* The EPA disagrees with the commenters and maintains that it has conducted the MACT floor analysis appropriately. Section 112(d) of the CAA requires us to establish emission limits for new sources based on the performance of the best-controlled similar source. The CAA does not specify that the similar source must be within the same source category or subcategory. To the contrary, our interpretation of section 112(d) is that we are obligated to consider similar sources from other source categories or subcategories in determining the best-controlled similar source for establishing MACT for new sources.

For new limited use and small units, we concluded that the best-controlled similar sources are found in the large subcategory. First, EPA determined the control technology used by the best controlled sources in the subcategory. For example, only units in the population database less than 10 MMBtu/hr (and not in the limited use subcategory) were used to determine the MACT floor control technology for units in the small subcategories. Second, EPA used information in the emissions test database to establish the emission level associated with the MACT floor control technology. The emissions test database did not contain test data for limited use or small boilers and process heaters. Section 112(d) of the CAA requires EPA to use information from similar sources to set the MACT floor. Such sources may not be in the same subcategory. Although the units in the small and limited use subcategories are different enough to warrant their own subcategory (*i.e.*, different purposes and operation), emissions of the specific types of HAP for which limits are being proposed are expected to be related more to the type of fuel burned and the type of control used, than to unit operation. Consequently, EPA determined that emissions information from large fuel-fired units could be used to establish MACT floor levels for the small and limited use subcategories because the fuels and controls are similar. The proposal preamble requested additional information from commenters to refine/revise the approach if necessary. No commenters provided emissions information for limited use or small subcategory boilers or process heaters.

*Comment:* Several commenters requested that EPA account for variability in fuel composition as MACT floors are established and to provide adequate allowances for inherent fuel supply variability. Some commenters argued that there is no flexibility in the rule to account for this variability and noted that coal composition can vary by location and also within an individual seam.

*Response:* As described in the memorandum ''Revised MACT Floor Analysis for the Industrial, Commercial, and Institutional Boilers and Process Heater National Emission Standards for Hazardous Air Pollutants Based on Public Comments'' in the docket, the calculation of numerical emission limits was a two-step analysis. The first step involved calculating a numerical average of the appropriate subset of emission test data. The second step involved generating and applying an appropriate variability factor to account for unavoidable variations in emissions due to uncontrollable variations in fuel characteristics and ordinary operational variability. Accounting for variability is appropriate in order to generate a more accurate estimation of the actual, long term, performance of a source (*e.g.*, the source occupying the median point in the top 12 percent). An emission test provides a momentary snapshot, not an estimation of continuous performance. In order to translate the former into the latter, we must account for that ordinary and unavoidable variability that the source is likely to experience over time. This gives us a more reasonable estimate of the actual level of emissions control that the unit is achieving. The EPA contends that by considering the variability of emissions information, we have indirectly incorporated variability in fuel, operating conditions, and sampling and analytical conditions because these parameters vary from emission tests conducted from one unit to another, and even within each test set of three measurements at a single unit. The most elementary measure of variation is range. Range is defined as the difference between the largest and smallest values. This is the variability methodology used in the proposed rule. That is, for each unit with multiple emissions tests conducted over time, the variability was calculated by dividing the highest three-run test result by the lowest three-run test result. The overall variability was calculated by averaging all the individual unit variability factors. This overall variability factor was multiplied by the overall average emission level to derive a MACT floor limit representative of the average emission limitation achieved by the top 12 percent of units. This approach adequately accounts for inherent fuel supply variability. Based on comments, EPA did conduct a more robust statistical analysis (t-test) of the mercury emissions data used in the MACT floor analysis to identify the 97.5th percent confidence limit. This analysis provided similar results to the variability analysis conducted in the proposed rule. Consequently, EPA decided not to change its variability methodology. A detailed discussion of the statistical analysis conducted is provided in the memorandum ''Statistical Analysis of Mercury Test Data Variability in Response to Public Comments on Determination of the MACT Floor for Mercury Emissions'' in the docket.

*Comment:* Several commenters supported EPA's finding that the MACT floor level of control for existing gaseous and liquid fuel units is no control. Other commenters noted that EPA has a clear statutory obligation to set emission standards for each listed HAP (the commenter cited legal briefs). One commenter specifically challenged EPA's determination of the MACT floor for organic pollutants. The commenter explained that EPA should rank the units for which emissions data is available according to the best performing units, not based on the add-on control level of 6 percent of the total population. The commenter noted that the U.S. Court of Appeals for the DC Circuit had squarely held, in the National Lime case, that EPA was not allowed to make a ''no control'' determination for a pollutant emitted by a listed category of sources.

*Response:* The EPA agrees that all factors which might control HAP emissions must be considered in making a floor determination for each subcategory. However, EPA disagrees that it must express the floor as a quantitative emission level in those instances where the sources on which the floor determination is based has not adopted or implemented any measure that would reduce emissions. For several subcategories and certain HAP, EPA has not identified any adjustments or other operational modifications that would materially reduce emissions by these units, and EPA had determined that no add-on controls are presently in use. In these circumstances, EPA has established appropriately the MACT floors for these sources as no emission reduction.

*Comment:* One commenter pointed out that the variability factor used to make the calculated MACT floor less stringent is not allowed by section 112 of the CAA. The commenter mentioned that the variability factors are not consistent, as one factor considers the fuel variability and the other factor considers the test data variability.

*Response:* Section 112(d)(2) of the CAA requires that emissions standards promulgated shall require the maximum degree of reductions in emissions that the EPA Administrator, taking into consideration the costs of achieving such emission reduction, determines is achievable for new and existing sources in the subcategory to which such emission standards applies. Accounting for variability is appropriate in order to generate a more accurate estimation of the actual, long term, performance of a source (*e.g.*, the source occupying the median point in the top 12 percent). An emission test provides a momentary snapshot, not an estimation of continuous performance. In order to translate the former into the latter, we must account for that ordinary and unavoidable variability that the source is like to experience over time. This give us a more reasonable estimate of the actual level of emissions control that the unit is achieving. As such, due to variations in fuel burned, and ordinary operational variability any emission limit set from a point source measurement alone may not be indicative of normal emissions or operations of the unit. Attempting to base a standard (either a floor standard, or a beyond-the-floor standard) solely on point measurements would lead to unachievable standards for all sources. Limits set by EPA must be achieved at all times, and it is important that the MACT floor limit adequately account for the normal and unavoidable variability in the process and in the operation of the control device.

Variability was assessed two ways. For existing subcategories, variability in emissions information was used to develop variability factors for all subcategories where emissions information was available. Variability in fuel content was used only in situations regarding determining the achievable MACT floor level for new sources from the emission test result on the best controlled similar source. This approach is appropriate since the main uncertainty associated with the emission test result from the best controlled similar source is fuel variability. Corresponding fuel analysis results were not available for the emissions test results from the best controlled similar source. Whereas, the average emission level of the best 12 percent of the units has, besides fuel variability, the uncertainty associated with operational and design variability of the various control devices installed on units that represent the best 12 percent of the units. For example, available fuel analysis information shows that mercury content of coal varies by a factor of 12.54. Dividing the highest mercury emission test result by the lowest mercury test results from coal-fired units included in units that represent the best 12 percent results in a variability factor of 20. Therefore, we concluded that fuel availability was inherently considered in the MACT floor analysis approach used for existing subcategories.

*Comment:* Many commenters requested that EPA revise the MACT floor methodology for mercury emission limits. The commenters contended that the variability factor was calculated inappropriately. Other commenters stated that EPA should account for variability in fuel composition in the MACT floor analysis. Other commenters expressed concern that the floor level of control was based on fabric filters, which has not been proven at all sources to reduce mercury.

*Response:* As discussed in the proposal preamble, the MACT floor analysis for mercury was based on a two step process. First the percentage of units with control technologies that could achieve mercury emissions reductions was determined using the boiler population databases. If the control technology analysis indicated that at least 12 percent of sources in the subcategory used a control device that could achieve mercury emissions reductions, then the control technology present at the median (6th percentile) was identified as the MACT floor control technology. The MACT floor level of control for mercury was identified as a fabric filter. The control effectiveness of fabric filters was based on emissions information for utility boilers that indicated that mercury emissions reductions were being achieved with this technology. In this case, we could use control efficiency information from another similar source category to supplement the information available in this source category because of the similarity in fuel burned, combustor type, and control methodology and operation. We maintain that fabric filters are still the appropriate level of control for the MACT floor.

Second, the emission limit associated with the MACT floor control technology was calculated using emissions information for units in the subcategory, whenever possible. For most of the subcategories developed, emissions information was adequate. Only for the emission limit for new source liquids and the variability factor for new source solids was fuel pollutant content incorporated into the MACT floor analyses. The mercury fuel content of coal from the utility industry was used in developing the variability factors for new solid fired units. This was done because mercury emissions are dependent on the quantity of mercury in the fuel burned. Coal available to utilities and industrial boilers and process heaters is expected to be similar, and coal is the solid fuel that is routinely used in such units that has generally the greatest degree of HAP variability. We maintain that the utility database used at proposal to develop the variability factor for new sources was adequate in establishing the MACT floor emission limit.

The EPA recognizes that the mercury emissions database for industrial boilers is limited. However, EPA is directed by the CAA to develop standards for sources using whatever data is available. Prior to proposal and during the Industrial Combustion Coordinated Rulemaking (ICCR) process, EPA conducted a thorough search for HAP emission test reports. This search was supported by industry, trade groups, and States. For criteria pollutants, such as PM, substantial emission information was available and gathered. For mercury and other HAP, this was not the case. Industrial boilers have not generally been required to test for HAP emissions. In the proposed rule, EPA requested commenters to provide additional emissions information. However, only one source provided any additional mercury emissions data. This information (test results from three additional coal-fired industrial boilers) was used to revise the mercury emission limit for existing sources. We also reviewed the mercury emission database used to develop the MACT floor emission limit for existing sources. After review, we determined that a revision to the variability factor was appropriate. The additional data and the revised variability factor was used to re-calculate the mercury emission limit to be 0.000009 lb/MMBtu (from 0.000007 lb/MMBtu at proposal). A detailed discussion of the revised MACT floor analysis conducted is provided in the memorandum ‘‘Revised MACT Floor Analysis for the Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants Based on Public Comments’’ in the docket.

Variability of the emissions data were incorporated into the final emission limits. The EPA contends that by considering the variability of emissions information, we have indirectly incorporated variability in fuel, operating conditions, and sampling and analytical conditions because these parameters vary from emission tests conducted from one unit to another, and even within one unit. The EPA does not consider it appropriate or feasible to incorporate variability from a multitude of parameters because such information is not available and cannot be correlated to the emissions information in the emissions test database. For the final rule, EPA did conduct a statistical analysis of the data to identify the 97.5th percent confidence interval. This analysis provided similar results to the variability analysis conducted in the proposed rule. Consequently, EPA decided not to change its variability methodology. A detailed discussion of the statistical analysis conducted is provided in the memorandum ‘‘Statistical Analysis of Mercury Test Data Variability in Response to Public Comments on Determination of the MACT Floor for Mercury Emissions’’ in the docket.

*Comment:* Several commenters contended that the California standards which the CO requirements are based on do not require CO CEMS, but require initial compliance testing and periodic subsequent performance testing.

*Response:* The commenters are correct that the California CO regulations do not require CO CEMS. The regulations do provide sources with the option of conducting annual testing or installing CO CEMS to demonstrate compliance with the CO emission limit. Because the regulations that were the basis of the MACT floor do not provide specifics on which boilers should conduct annual testing and which should use CO CEMS, we reviewed the cost information provided by the commenters to make this determination. In considering the additional cost information and reviewing the cost information used in the proposed rule, the EPA decided that changes to the CO compliance requirements were warranted. The final rule requires that new units with heat input capacities less than 100 MMBtu/hr conduct initial and annual performance tests for CO emissions. New units with heat input capacities greater or equal to 100 MMBtu/hr are still required to install, operate, and maintain a CO CEMS.

Regardless of whether the California regulations do or do not require CO CEMS, we would have reviewed the need for continuous monitoring and operating limits in order to ensure the most accurate indication of proper operation of the control system. The purpose of all of the minimum operating parameter limits in the standard is to ensure continuous compliance by ensuring that the air pollution control equipment is operating as they were during the latest performance test demonstrating compliance with the emission limits. The operating parameters are established as ''minimum'' to provide enforceable boundaries in their operation. Operating outside the bounds of the minimum parameters may lead to increased air emissions.

The EPA would also like to clarify that operation above the CO limit constitutes a deviation of the work practice standard. However, the determination of what deviations constitute violations of the standard is up to the discretion of the entity responsible for enforcement of the standards.

### *F. Beyond the MACT Floor*

*Comment:* Many commenters contended that carbon injection should have been required as a beyond-the-floor option. Other commenters supported EPA's decision to not require any controls beyond-the-floor.

*Response:* For the final rule, EPA maintains that options beyond the MACT floor are not appropriate for the standard. The EPA is required by the CAA to set the standard at a minimum on the best controlled 12 percent of sources (for existing units) or best controlled similar source (for new units). The CAA also requires EPA to consider costs and non-air quality impacts and energy requirements when considering more stringent requirements than the MACT floor. As documented in the memorandum ''Methodology for Estimating Costs and Emissions Impacts for Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants'' in the docket, EPA did consider the cost and emission impacts of a variety of regulatory options more stringent than the MACT floor for each subcategory. The EPA recognizes that for some subcategories, more stringent controls than the MACT floor can be applied and achieve additional emissions reductions. However, EPA also determined that the cost impacts of such controls were very high. Considering both the costs and emissions reductions, EPA determined that it would be infeasible to require any options more stringent than the floor level.

For the final rule, EPA maintains that carbon injection should not be required as an above the floor technology. As discussed in the proposal preamble, we identified one existing industrial boiler that was using carbon injection. The emissions data that we obtained from the boiler indicated that this carbon injection unit was not achieving mercury emissions reductions. This result led us to conclude that it was not the new source floor level of control. However, there may have been other reasons for the ineffectiveness of this system (*e.g.*, low inlet mercury levels, insufficient carbon injection rate, ESP instead of fabric filter for PM control). Therefore, we considered carbon injection as a beyond-the-floor option, but decided that while this control technique has been used in other source categories, there is no demonstrated evidence that it would work for industrial boilers and process heaters because the type of mercury emitted and properties of the emission streams are sufficiently different for boilers and process heaters and other source categories.

### *G. Work Practice Requirements*

*Comment:* Many commenters requested EPA consider exceedences of the CO limit to be a trigger for corrective action rather than a violation.

*Response:* In the final rule, we have clarified that an exceedence of the CO limit constitutes a deviation of the work practice standard. An observed exceedence of a monitoring parameter is not an automatic violation. You are required to report any deviation from an applicable emission limitation (including operating limit). We will review the information in your report along with other available information to determine if the deviation constitutes a violation. The determination of what emission or operating limit deviation constitutes violations of the standard is up to the discretion of the entity responsible for enforcement of the standard.

### *H. Compliance*

*Comment:* Many commenters requested that EPA simplify and write the fuel monitoring requirements to not require retesting of fuel for changes in fuel supplier.

*Response:* We agree that the fuel monitoring requirements in the proposal needed to be clarified and explained further. Therefore, we have clarified the fuel analysis options in the final rule. If you elect to demonstrate compliance with the HCl, mercury, or total selected metals limit by using fuel which has a statistically lower pollutant content than the emission limit, then your operating limit is the emission limit of the applicable pollutant. Under this option, you are not required to conduct performance tests (*i.e.* stack tests).

If you demonstrate compliance with the HCl, mercury, or total selected metals limit by using fuel with a statistically higher pollutant content than the applicable emission limit, but performance tests demonstrate that you can meet the emission limits, then your operating limits are the operating limits of the control device (if used) and the fuel pollutant content of the fuel type/mixture burned.

The final rule specifies the testing methodology and procedures and the initial and continuous compliance requirements to be used when complying with the fuel analysis options. Fuel analysis tests for total chloride, gross calorific value, mercury, metal analysis, sample collection, and sample preparation are included in the final rule.

If you elect to comply based on fuel analysis, you are required to statistically analyze, using the z-test, the data to determine the 90th percentile confidence level. It is the 90th percentile confidence level that is required to be used to determine compliance with the applicable emission limit. The statistical approach is required to assist in ensuring continuous compliance by statistically accounting for the inherent variability in the fuel type.

You are required to recalculate the fuel pollutant content only if you burn a new fuel type or fuel mixture. You are required to conduct another performance test if you demonstrate compliance through performance testing, you burn a new fuel type or mixture, and the results of recalculating the fuel pollutant content are higher than the level established during the initial performance test.

*Comment:* Many commenters requested EPA consider exceedences of parametric limits to be a trigger for corrective action rather than a violation.

*Response:* In the final rule, we have clarified that an exceedence of the parametric limits constitute a deviation of the operating limits. An observed exceedence of a monitoring parameter is not an automatic violation. You are required to report any deviation from an applicable emission limitation (including operating limit). We will review the information in your report along with other available information to determine if the deviation constitutes a violation. The determination of what emission or operating limit deviation constitutes violations of the standard is up to the discretion of the entity responsible for enforcement of the standard.

*Comment:* Many commenters requested EPA revise the opacity requirements. Commenters objected to the provision in the proposed NESHAP that would establish an opacity ''operating limit'' based on the initial performance test. Some commenters contended that EPA has provided no data or references demonstrating a relationship between opacity and particulate, total metals, or mercury emissions. Other commenters argued that the proposed opacity limit approach for dry control devices is unworkable due to the inherent inability of continuous opacity monitors (COMS) to accurately measure opacity at levels less than 10 percent. Some commenters argued that the performance and opacity achieved during the initial test may not be representative of the unit's performance. Other commenters explained that equipment condition, fuel and operating variations, and other uncontrollable parameters may result in varying emissions and emissions control equipment efficiencies over time. Commenters suggested requiring the NSPS limits for opacity rather than setting opacity based on the initial compliance test.

*Response:* We have reviewed the information provided by the commenters, and agree that the opacity operating limit requirements in the proposed rule are not appropriate for this source category. Because of the variability in fuels burned, the combination of fuels burned, and the typical operation of boilers and process heaters, we have decided that an opacity limit set based on the initial performance test may not be representative of the units typical performance.

We have revised the opacity operating limit provision by requiring existing units to maintain opacity to less than or equal to 20 percent (based on 6-minute averages) except for one 6-minute period per hour of not more than 27 percent. This is the opacity limit contained in the current NSPS for industrial boilers, which has a similar PM emission limit as the final rule. Therefore, it was determined that it was appropriate to include a similar opacity level as the control device operating limit for existing units. New sources can maintain their opacity operating limit to less than or equal to 10 percent (based on 1-hour block averages). This level appears to be the lowest opacity level currently applicable to industrial boilers in State regulations.

*Comment:* Several commenters objected to the requirement to conduct performance testing at worst case conditions. The commenters found this requirement to be unrealistic because stack testing must be scheduled well in advance and worst-case conditions depend on fuel, load, and many other variables, making it impossible to assure that the testing will occur during worst-case conditions. Two commenters contended there can be no guarantee that mineral properties for a fuel source at the time of the baseline test can be guaranteed beyond the content identified during purchase contract negotiations with a fuel supplier. Two commenters suggested that EPA define what worst case conditions are because sources do not have the experience to determine worst-case representative process conditions.

*Response:* We agree that more direction and clarification is needed regarding testing at worst case conditions. We have modified fuel sampling requirements and performance testing fuel use requirements to simplify compliance. During performance testing, sources are required to burn the type of fuel or mixture of fuel types that have the highest concentration of regulated HAP. This, in combination with revised fuel sampling requirements (*e.g.*, based on fuel type and not on supplier, etc.), will simplify the determination of the fuel blend during the performance test. Sources are also required to conduct performance tests under representative full load operating conditions.

*Comment:* Several commenters objected to the requirement for annual performance tests because they felt that it is overly burdensome given the ongoing compliance demonstrations required by the NESHAP. Several commenters suggested that initial performance testing should be required with subsequent performance testing occurring every 3 to 5 years. Some commenters stated that 5-year test intervals are consistent with title V permits and have been allowed in other MACT standards (*e.g.* Hazardous Waste Combustors).

*Response:* We have worked to minimize the testing and monitoring requirements of the final rule while retaining the ability to ensure compliance with the emission limits and work practice requirements. We are providing an option for sources to conduct performance testing once every 3 years if they conduct successful performance testing for 3 consecutive years. We are also allowing sources to demonstrate compliance with the HCl, mercury, and total selected metals emission limits through fuel testing if they do not need emission control devices to achieve the standard.

### *I. Emissions Averaging*

In the proposal preamble, we solicited comments on an emissions averaging or bubbling compliance alternative, as part of the EPA's general policy of encouraging the use of flexible compliance approaches where they can be properly monitored and enforced, and whether EPA should include emissions averaging in the final rule. Emissions averaging can provide sources the flexibility to comply in the least costly manner while still maintaining regulation that is workable and enforceable. We requested comment on an averaging approach for determining compliance with the non-mercury metallic HAP, HCl, mercury, and/or PM standards for existing sources. We indicated that averaging would allow owners and operators to submit non-mercury metals, mercury, HCl, and/or PM emissions limits to the EPA Administrator for approval for each existing boiler in the averaging group such that if these emission limits are met, the total emissions from all existing boilers in the averaging group are less than or equal to emission limits (for non-mercury metals, mercury, HCl, or PM) applicable to units in the particular subcategory. We indicated also that averaging would not be applicable to new sources and could only be used between boilers and process heaters in the same subcategory. Also, owners or operators of existing sources subject to the Industrial Boiler New Source Performance Standards NSPS (40 CFR part 60, subparts Db and Dc) would be required to continue to meet the PM emission standard of that NSPS regardless of whether or not they are averaging.

Emissions averaging has been incorporated into the final rule as an alternative means of complying with the final rule. Emissions averaging allows an individual affected unit emitting above the allowable emission limit required by the final rule to comply with that emission limit by averaging its emissions with other affected units at the same facility emitting below the allowable emission limit required by the final rule.

*Comment:* Many commenters supported including averaging in the final rule. Commenters cited numerous reasons, including cost effectiveness, energy efficiency, greater flexibility in compliance, and greater environmental benefit. Commenters also cited 40 CFR part 63, subpart MM, Pulping Chemical Recovery Combustion MACT as a precedent for including emissions averaging in MACT standards. Two commenters disagreed with allowing emissions averaging, stating that it would complicate compliance determinations, does not fit within the CAA mandate, and is inconsistent with the purpose of CAA section 112. Many of those commenters who supported emissions averaging recommended additional flexibility, such as including new units, and bubbling across subcategories.

*Response:* The final rule includes an emissions averaging compliance alternative because emissions averaging represents an equivalent, more flexible, and less costly alternative to controlling certain emission points to MACT levels. We have concluded that a limited form of averaging could be implemented and not lessen the stringency of the standard. We agree with the commenters that some type of emissions averaging would provide flexibility in compliance, cost and energy savings to owners and operators. We also recognize that we must ensure that any emissions averaging option can be implemented and enforced, will be clear to sources, and most importantly, will achieve no less emissions reductions than unit by unit implementation of the MACT requirements.

The final rule is not the first NESHAP to include provisions permitting emission averaging. In general, EPA has concluded that it is permissible to establish within a NESHAP a unified compliance regimen that permits averaging across affected units subject to the standard under certain conditions. Averaging across affected units is permitted only if it can be demonstrated that the total quantity of any particular HAP that may be emitted by that portion of a contiguous major source that is subject to the NESHAP will not be greater under the averaging mechanism than it would be if each individual affected unit complied separately with the applicable standard. Under this rigorous test, the practical outcome of averaging is equivalent in every respect to compliance by the discrete units, and the statutory policy embodied in the MACT floor provisions is, therefore, fully effectuated.

The EPA has generally imposed certain limits on the scope and nature of emissions averaging programs. These limits include: (1) No averaging between different types of pollutants, (2) no averaging between sources that are not part of the same major source, (3) no averaging between sources within the same major source that are not subject to the same NESHAP, and (4) no averaging between existing sources and new sources.

The final rule fully satisfies each of these criteria. Accordingly, EPA has concluded that the averaging of emissions across affected units permitted by the final rule is consistent with the CAA. In addition, EPA notes that the provision in the final rule that requires each facility that intends to utilize emission averaging to submit an emission averaging plan provides additional assurance that the necessary criteria will be followed. In this emission averaging plan, the facility must include the identification of (1) all units in the averaging group, (2) the control technology installed, (3) the process parameter that will be monitored, (4) the specific control technology or pollution prevention measure to be used, (5) the test plan for the measurement of particulate matter (or selected total metals), hydrogen chloride, or mercury emissions, and (6) the operating parameters to be monitored for each control device. Upon receipt, the regulatory authority will not approve an emission averaging plan containing averaging between emissions of different types of pollutants or between sources in different subcategories.

The final rule excludes new affected sources from the emissions averaging provision. New sources have historically been held to a stricter standard than existing sources because it is most cost effective to integrate state-of-the-art controls into equipment design and to install the technology during construction of new sources. One reason we allow emissions averaging is to give existing sources flexibility to achieve compliance at diverse points with varying degrees of add-on control already in place in the most cost-effective and technically reasonable fashion. This concern does not apply to new sources which can be designed and constructed with compliance in mind.

Only existing large solid fuel units, as defined in the final rule, can be included in the emissions averaging compliance alternative. Of the nine subcategories established for existing sources, existing large solid fuel units is the only subcategory for which multiple HAP emissions limits apply. For the existing small solid fuel subcategory and the six existing gaseous and liquid fuel subcategories, no HAP emissions limits are included in the final rule and, thus, it would not be appropriate to allow these units to average emissions. As for the existing limited use solid fuel subcategory, since these units, as defined in the final rule, operated on a limited basis (capacity factor of less than 10 percent) and are subject only to a less stringent PM emissions limit (as a surrogate for non-mercury metals), it would be inappropriate to allow these units to average emissions.

With concern about the equivalency of emissions reductions from averaging and non-averaging in mind, the EPA Administrator is also imposing under the emission averaging provision caps on the current emissions from each of the sources in the averaging group. The emissions for each unit in the averaging group would be capped at the emission level being achieved on the effective date of the final rule. These caps would ensure that emissions do not increase above the emission levels that sources currently are designed, operated, and maintained to achieve. In the absence of performance tests, in documenting these caps, these sources will documented the type, design, and operating specification of control devices installed on the effective date of the final rule to ensure that existing controls are not removed or lessen. By including this provision in the final rule, the EPA Administrator has taken yet another step to assist in ensuring that emission averaging results in environmental benefits equivalent or better over what would have happened without emission averaging.

The inclusion of emissions averaging into rules and the decision on how to design an emission averaging approach for a particular source category must be evaluated for each source category.

### *J. Risk-based Approach*

*Comment:* Multiple commenters supported EPA's incorporation of risk-based concepts into the MACT Program. One commenter stated that providing risk-based applicability criteria for sources whose HAP emissions do not pose a significant risk is appropriate. Several commenters stated that there is clear legal authority in the CAA to construct NESHAP based on risk, and such an approach is very appropriate in the case of the Industrial Boiler MACT. The commenter also noted that the regulatory framework exists within their

State to implement such an approach. Several commenters added that risk-based alternatives will function as indirect emission limits that must be maintained by the facilities to assure that the criteria are met, and, thus, such alternatives for low-risk facilities are supportable by EPA's authority under section 112(d)(4) and 112(c)(9) of the CAA and EPA's inherent *de minimis* authority. Another commenter asserted that there are ways to structure the rule to focus on facilities that pose significant risks and avoid imposition of high costs on facilities that pose little risk. An appropriate approach would be to allow individual facilities to conduct a risk assessment to show that they pose insignificant risks to the public. However, one commenter stated that it is not appropriate for State and local programs to determine which facilities should be exempted from MACT. Several commenters supported a risk-based compliance alternative for HCl.

*Response:* The EPA has determined that it can establish applicable health-based emission standards for HCl and manganese for affected sources in this category pursuant to its authority under section 112(d)(4) of the CAA. As a result, EPA has included such standards in the final rule as alternative compliance requirements. Under this approach, affected sources can choose to comply with either the MACT-based emission limits or the health-based emission limits. Sources which choose to comply with the health-based emission limit(s) will remain subject to those limits, but will need to comply with testing, monitoring and reporting requirements commensurate with the compliance option they have chosen. Such health-based standards are consistent with both the commenters' support for an approach that minimizes the impact on low-risk facilities and EPA's statutory mandate under section 112.

Section 112(d)(4) of the CAA authorizes EPA to consider established health thresholds, with an ample margin of safety, when promulgating emission standards under section 112. Hydrogen chloride and Mn are two pollutants for which health thresholds have been established. Issues concerning our legal authority to establish health-based emission standards under section 112(d)(4) are discussed in detail below.

We are not using CAA section 112(c)(9) for the final rule, and there is no delisting of categories or subcategories, as would be consistent with section 112(c)(9).

The criteria defining how affected sources demonstrate that they meet the threshold emissions levels for the health-based compliance alternative(s) is included in appendix A to the final rule. The criteria in appendix A to the final rule were developed for and apply only to the Boiler and process heater source category and are not applicable to other source categories. The final rule provides two ways that an affected source may demonstrate compliance with the health-based emission limits. The first option is through the use of lookup tables which allow facilities to determine, using a limited number of site-specific input parameters, whether emissions from boilers and process heaters might cause a hazard index (HI) limit for non-carcinogens to be exceeded. The second option is a modeling approach which allows those facilities that do not match the site-specific input parameters on which the lookup tables are based to demonstrate compliance with the health-based emission limits by modeling using site-specific information.

The affected source will have to demonstrate that it meets the criteria established by today's final rule and then assume Federally enforceable limitations, as described in appendix A of the final rule, that ensure their specified HAP emissions do not subsequently increase to exceed levels reflected in their demonstrations.

*Comment:* Multiple commenters are opposed to the risk-based exemptions. Some noted that the proposal to include risk-based exemptions is critically flawed and opposes adoption of the risk-based exemptions.

One commenter stated that the inclusion of case-by-case risk-based exemptions into the first phase of the MACT program will negate the legislative mandate and jeopardize the effectiveness of the national air toxics program to adequately protect public health and the environment and to establish a level playing field. The commenter was very concerned that EPA referenced a fundamentally flawed interpretation of CAA section 112(d)(4) written by an industry (AF&PA) subject to regulation. Of particular concern was AF&PA's unprecedented proposal to include ''*de minimis* exemptions'' and ''cost'' in the MACT standard process.

One commenter stated that the use of risk-based concepts to evade MACT applicability is contrary to the intent of the CAA and is based on a flawed interpretation of section 112(d)(4) of the CAA. The commenter added that the CAA requires a technology-based floor level of control and does not provide exclusions for risk or secondary impacts from applying the MACT floor.

One commenter stated that in separate rulemakings and lawsuits, EPA has adopted legal positions and policies that refute and contradict the very risk-based and cost-based approaches contained in the proposals. In these other arenas, the commenter contended that EPA has properly rejected risk assessment to alter the establishment of MACT standards. The EPA also has properly rejected cost in determining MACT floors and in denying a basis for avoiding the MACT floor.

Several commenters stated that the preamble discussion of the risk-based approaches is not sufficient to allow for complete public comment and, therefore, it would not be appropriate for EPA to go directly to a final rule (without reproposal) with any of the approaches outlined in the proposal.

*Response:* We are not identifying and deleting a subcategory of sources in this source category pursuant to the authority of CAA section 112(c)(9). Legal issues associated with the health-based provisions are addressed below and in the comment/response memorandum.

As discussed above, we are, however, including in the final rule alternative health-based emission standards for HCl and TSM based on our authority under CAA section 112(d)(4). Section 112(d)(4) authorizes EPA to consider health thresholds, with an ample margin of safety, in establishing emission standards. The analysis necessary to do this can generally be characterized as a risk analysis. Thus, we disagree with the commenter that we must wait for implementation of CAA section 112(f) before utilizing risk analysis.

*Comment:* Many commenters stated that the proposal to include risk-based exemptions is contrary to the 1990 CAA Amendments (CAAA) which calls for MACT standards based on technology rather than risk as a first step. They added that congress incorporated the residual risk program under CAA section 112(f) to follow the MACT standards (not to replace them). The commenters added that the need for the technology-based approach has been recently reinforced by the results of the National Air Toxics Assessment (NATA), which indicates that exposure to air toxics is very high throughout the country in urban and remote areas. Several commenters added that risk-based approaches will be used separately to augment and improve technology-based standards that do not adequately provide protection to the public. One commenter added that they have been unable to substantiate the basis for EPA's support of the regulatory relief sought by industry through risk-based exemptions and that, in fact, the use of risk assessment at this stage of the

MACT program is directly opposed to title III of the CAA.

*Response:* We disagree that inclusion of health-based compliance alternatives, in the form of emission standards based on the authority of section 112(d)(4) of the CAA, in the final rule is contrary to the 1990 CAAA. The final rule is a technology-based standard developed using the procedures dictated by section 112 of the CAA. The only difference between the final rule and other MACT is that we used our discretion under section 112(d)(4) to base appropriate parts of the final rule on established health thresholds, with an ample margin of safety. The final rule is particularly well-suited for a health-based compliance alternative, established pursuant to the criteria set forth in section 112(d)(4). In addition to the fact that there are established health thresholds for HCl and manganese, EPA has determined that many of the facilities in this source category do not emit these pollutants in amounts that pose a significant risk to the surrounding population. Those sources that can demonstrate that the emissions of acid gases and manganese meet the threshold emission levels will be in compliance with the MACT. The criteria are based on health-protective estimates of risk and the threshold emission levels will provide ample protection of human health and the environment.

Inclusion of health-based compliance alternatives in the final rule does not alter the MACT program. Rather, it merely represents EPA availing itself, in appropriate circumstances, of the authority Congress granted it in section 112(d)(4) of the CAA. We recognize that such provisions are only appropriate for certain HAP, and our decision-making process required source category-specific input from stakeholders.

Although the NATA modeling study may show measurable concentrations of toxic air pollution across the country, these data do not suggest that EPA should not establish health-based emission standards pursuant to its authority under CAA section 112(d)(4) when it determines that it is appropriate to do so. The alternative health-based emission standards included in the final rule will ensure that affected sources which choose to comply with those standards do not emit HCl and/or manganese at levels that are harmful to public health.

*Comment:* Many commenters stated that the proposal to allow risk-based exemptions would divert back to the time-consuming NESHAP development process that existed prior to the CAAA of 1990. The commenters asserted that under this process, which began with a risk assessment step, only eight NESHAP were promulgated during a 20-year period. The commenters continued that if the proposed approaches are inserted into upcoming standards, the commenters fear the MACT program (which is already far behind schedule) would be further delayed. One commenter supported EPA efforts to determine alternative MACT setting methodologies but strongly recommended that these be pursued separately from the final rule. The commenter contended that this will provide for timely issuance of final RICE and Boiler/Process Heater MACT rules relative to the settlement deadline. Two commenters stated that delays could be exacerbated by litigation following legal challenges to the rules, and such delays would trigger the MACT hammer, which would unnecessarily burden the State and local agencies and the industries. The commenters concluded that further delay is unacceptable. The commenters did not want to be in a position of implementing the CAA section 112(j) program and urged EPA to not delay the issuance of any MACT standard. The commenters noted that according to a recently proposed EPA rule regarding section 112(j), the regulated community and State and local agencies would have to proceed with part 2 permit applications, followed by case-by-case MACT, if EPA misses the newly agreed-upon MACT deadlines by as little as 2 months. This would be time consuming, costly, and burdensome for both regulators and the regulated community.

*Response:* We disagree that allowing health-based compliance alternatives in the final rule will alter the MACT program or affect the schedule for promulgation of the remaining MACT standards. We do not anticipate any further delays in completing the remaining MACT standards. The setting of alternative health-based emission standards in the final rule affects only the final rule.

The approach taken in the final rule is particularly well-suited to acid gases and manganese, which are the only pollutants included in the health-based compliance alternatives. For many facilities, these pollutants are currently emitted in amounts that do not expose anyone in surrounding population to concentrations above the established health thresholds. As a result, emissions of HCl and/or manganese at these facilities do not pose a significant risk to the surrounding population. Only those Boiler facilities that demonstrate that their emissions are below the health-based emission standard(s), are eligible for the compliance alternatives.

Including health-based compliance alternatives for boiler sources does not mean that EPA will automatically provide such alternatives for other industries. Rather, as has been the case throughout the MACT rule development process, EPA will undertake in each individual rule to determine whether it is appropriate to exercise its discretion to use its authority under CAA section 112(d)(4) in developing applicable emission standards. The Boilers NESHAP is being promulgated by the February 2004 court-ordered deadline.

*Comment:* Many commenters stated that the risk-based proposal removes the level-playing field that would result from the proper implementation of technology-based MACT standards. The commenters added that establishing a baseline level of control is essential to prevent industry from moving to areas of the country that have the least stringent air toxics programs, which was one of the primary goals of developing a uniform national air toxics program under section 112 of the 1990 CAA amendments. The risk-based approaches would jeopardize future reductions of HAP in a uniform and consistent manner across the nation.

*Response:* Providing health-based compliance alternatives for sources that can meet them in the final rule will assure the application of a uniform set of requirements across the nation. The final rule and its criteria for demonstrating eligibility for the health-based compliance alternatives apply uniformly to boilers across the nation in the large solid fuel-fired subcategories. The final rule establishes a two baseline levels of emission reduction for HCl and manganese, one based on a traditional MACT analysis and the other based on EPA's evaluation of the health threat posed by emissions of these two pollutants. All Boiler facilities must meet one of these baseline levels, and all facilities with boilers in the applicable subcategories have the same opportunity to demonstrate that they can meet the alternative health-based emission standards. The criteria for qualifying to comply with the alternative health-based emission standards are not dependent on local air toxics programs. Therefore, concerns regarding facilities moving to areas of the country with less-stringent air toxics programs should be alleviated.

*Comment:* Multiple commenters stated that section 112(d)(4) of the CAA provides EPA with authority to exclude sources that emit threshold pollutants from regulation. The commenters indicated that section 112(d)(4) allows for discretion in developing MACT standards for HAP with health thresholds. The commenters added that the use of section 112(d)(4) authority also is supported by CAA's legislative history, which emphasizes that Congress included section 112(d)(4) in the CAA to prevent unnecessary regulation of source categories.

One commenter pointed out that Congress does not differentiate between technology-based ''emission standards'' set under CAA section 112(d)(3) versus ''health threshold'' based ''emission standards'' set under CAA section 112(d)(4). Instead, the statute explicitly treats emission standards promulgated under section 112(d)(3) and 112(d)(4) as equivalent by not distinguishing between those emission standards under the residual risk provisions of CAA section 112(f). One commenter added that EPA is permitted to establish alternative standards as long as it ensures that ambient concentrations are less than the health thresholds plus a margin of safety and the emissions do not cause adverse environmental effects. Multiple commenters pointed out that EPA has exercised such authority and cited the NESHAP for Chemical Recovery Combustion Sources at Kraft, Soda, Sulfite, and Stand-Alone Semichemical Pulp Mills. In addition, the commenters added that in that NESHAP, EPA identified circumstances in which they would decline to exercise 112(d)(4) authority-where significant or widespread environmental harm would occur as a result of emissions from the category and the estimated health thresholds are subject to substantial scientific uncertainty. The commenters concluded that EPA determined that these considerations were not relevant to emissions from the pulp and paper source category, and the commenters stated that the same is true for their source categories and that the same treatment is warranted for many facilities within the source categories. The commenters noted that facilities that cannot meet the risk criteria would remain subject to the MACT requirements.

One commenter added that the risk-based approaches are squarely in line with the plain meaning of section CAA 112(d)(4). The commenters cited the Senate report (Sen Rep. No. 228, 101st Congress, 1st Sess 175–6 (1990)) showed that Congress contemplated that sources within the same category or subcategory would be subject to varied regulatory requirements, depending on the risk they pose to public health. The commenters added that nothing in the statutory definition of ''emission standard'' suggests that the term is limited to a requirement for the installation of control technology. The commenters added that the risk-based compliance alternatives would meet this requirement because they would apply to an entire source category or subcategory. The EPA could create a subcategory for low-risk sources and tailor an emission standard to this subcategory, or apply to all sources in the category a NESHAP containing multiple compliance options, one or more being risk-based.

Multiple commenters stated that the plain meaning of CAA section 112(d)(4) does not allow EPA to make MACT standards for individual sources. Two commenters noted that section 112(d)(4) states that ''with respect to pollutants for which a health threshold has been established, the EPA Administrator may consider such threshold level, with ample margin of safety, when establishing emission standards under this subsection.''

Several commenters contended that EPA has misinterpreted the provision in CAA section 112(d)(4) in that section 112(d)(4) does not state that EPA can use applicability thresholds ''in lieu of'' the CAA section 112(d)(3) MACT floor requirements. The commenter interpreted section 112(d)(4) to state that health based thresholds can be considered when establishing the degree of the MACT floor requirements, but it should not be used to supplant the requirements established pursuant to section 112(d)(3).

Many commenters stated that the legislative history of CAA section 112(d)(4) clearly rejects EPA's proposed facility-by-facility MACT exemptions. The commenters noted that Congress considered and rejected the applicability cutoffs upon which EPA now solicits comment. The commenters noted that the House version of the 1990 Amendments allowed States to issue permits that exempted a source from compliance with MACT rules if the source presented sufficient evidence to demonstrate negligible risk, and the Senate version of the 1990 Amendments contained no such provision. In conference, Congress considered both the House and Senate versions and rejected the House bill's exemption for specific facilities in favor of the Senate bill's language.

*Response:* The EPA has properly exercised the authority granted to it pursuant to CAA section 112(d)(4) of the CAA in establishing health-based emission standards for HCl and manganese which are applicable to the large solid fuel-fired subcategory. Section 112(d)(4) authorizes it to by-pass the mandate in section 112(d)(3) in appropriate circumstances. Those circumstances are present in the large solid fuel-fired Boiler subcategories.

Section 112(d)(4) of the CAA provides EPA with authority, at its discretion, to develop health-based emission standards for HAP ''for which a health threshold has been established,'' provided that the standard reflects the health threshold ''with an ample margin of safety.'' (The full text of the section 112(d)(4): ''[with respect to pollutants for which a health threshold has been established, the Administrator may consider such threshold level, within an ample margin of safety, when establishing emission standards under this subsection.'')

Both the plain language of CAA section 112(d)(4) and the legislative history cited above indicate that EPA has the discretion under section 112(d)(4) to develop health-based standards for some source categories emitting threshold pollutants, and that those standards may be less stringent than the corresponding ''floor''-based MACT standard would be. The EPA's use of such standards is not limited to situations where every source in the category or subcategory can comply with them. As is the case with technology-based standards, a particular source's ability to comply with a health-based standard will depend on its individual circumstances, as will what it must do to achieve compliance.

In developing health-based emission standards under CAA section 112(d)(4), EPA seeks to assure that those standards ensure that the concentration of the particular HAP to which an individual exposed at the upper end of the exposure distribution is exposed does not exceed the health threshold. The upper end of the exposure distribution is calculated using the ''high end exposure estimate,'' defined as ''a plausible estimate of individual exposure for those persons at the upper end of the exposure distribution, conceptually above the 90th percentile, but not higher than the individual in the population who has the highest exposure'' (EPA Exposure Assessment Guidelines, 57 FR 22888, May 29, 1992). Assuring protection to persons at the upper end of the exposure distribution is consistent with the ''ample margin of safety'' requirement in section 112(d)(4).

We agree that section 112(d)(4) is appropriate for establishing emission standards for HCl and manganese applicable to the large solid fuel-fired subcategories, and, therefore, we have established such standards as an alternate compliance requirement for affected sources in those subcategories. Affected sources in the large solid fuel-fired subcategories which believe that they can demonstrate compliance with one or both of the health-based emission standards may choose to comply with those standards in lieu of the otherwise applicable MACT-based standard.

For purposes of the final rule, we are not considering background HAP emissions in developing the section CAA 112(d)(4) compliance alternatives. As we indicated in the Residual Risk Report to Congress, however, the Agency intends to consider facility-wide HAP emissions in future CAA section 112(f) residual risk actions.

*Comment:* Many commenters contended that the proposal will place a very intensive resource demand on State and local agencies to review source's risk assessments, and State/local agencies may not have expertise in risk assessment methodology or the resources needed to verify information (*e.g.*, emissions data and stack parameters) submitted with each risk assessment.

Other commenters stated that a risk-based program can be structured and implemented in a manner that does not adversely impact limited State resources. One commenter asserted that EPA should work closely with States and industry to implement the risk-based approach in a non-burdensome manner. Another commenter stated that the risk-based approaches, like other MACT standards, would simply be incorporated into each State's existing title V program. The commenter concluded that because the title V framework already exists, the addition of a risk-based MACT standard would not require States to overhaul existing permitting programs. Another commenter contended that the final MACT rule itself should set forth the applicability criteria—including the threshold levels of exposure—that sources must meet to qualify for a risk-based determination. Each source would have the burden of demonstrating that its exposures are below this limit and, therefore, the States would not be required to develop their own risk assessment guidance or to conduct source-specific risk assessments.

*Response:* The health-based emission limits for HCl and TSM which EPA has adopted in the final rule should not impose significant resource burdens on States. Further, the required compliance demonstration methodology is structured in such a way as to avoid the need for States to have significant expertise in risk assessment methodology. We have considered the commenters' concerns in developing the criteria defining eligibility for these compliance alternatives, and the approach that is included in the final rule provides clear, flexible requirements and enforceable compliance parameters. The final rule provides two ways that a facility may demonstrate eligibility for complying with the alternative health-based emission standard. First, look-up tables, which are included as Tables 2 (HCl) and 3 (manganese) in appendix A of the final rule, allow facilities to determine, using a limited number of site-specific input parameters, whether emissions from their sources might cause a hazard index limit (hazard quotient in the case of manganese) to be exceeded. If a facility cannot demonstrate eligibility using a look-up table, a modeling approach can be followed. Appendix A to the final rule presents the criteria for performing this modeling.

Regarding commenters' concerns with looking for a threshold level for carcinogens, the compliance alternatives only apply to HCl and manganese, which are not currently expected to be carcinogens. Also, the concern expressed by a commenter about exempting a facility based on limited emission data if EPA established a subcategory listing low-risk sources is not relevant here, because we have not used CAA section 112(c)(9) authority to establish a low-risk subcategory for the Industrial/Commercial/Institutional Boilers and Process Heaters source category. With respect to guidance for performing site-specific modeling, all of the procedures for performing such modeling are available in peer-reviewed scientific literature and, therefore, no additional guidance needs to be developed.

Only a portion of the major facilities in the large solid fuel-fired boilers and process heaters subcategory will submit eligibility demonstrations for the compliance alternatives. Of this portion of major sources, most will be able to demonstrate eligibility based on simple analyses (*e.g.*, using the look-up tables provided in appendix A of the final rule). However, it is likely that some facilities will require more detailed modeling. The criteria for demonstrating eligibility for the compliance alternatives are clearly spelled out in the final rule. Because these requirements are clearly spelled out and because any standards or requirements created under CAA section 112 are considered applicable requirements under 40 CFR part 70, the compliance alternatives would be incorporated into title V programs, and States would not have to overhaul existing permitting programs.

Finally, with respect to the burden associated with ongoing assurance that facilities which opt to do so continue to comply with the health-based compliance alternatives, the burden to States will be minimal. In accordance with the provisions of title V of the CAA and part 70 of 40 CFR (collectively ''title V''), the owner or operator of any affected source opting to comply with the health-based emission standards will be required to certify compliance with those standards on an annual basis. Additionally, before changing key parameters that may impact an affected source's ability to continue to meet one or both of the health-based emission standards, the affected source is required to evaluate its ability to continue to comply with the health-based emission standard(s) and submit documentation to the permitting authority supporting continued eligibility for the compliance alternative.

The promulgation of specific alternative health-based emission limits and a uniform methodology for demonstrating compliance with those alternatives alleviates any concern regarding the public process required in reviewing/approving the proposed approaches and making substantial changes to existing regulations. It also addresses concerns regarding the costs and resources associated with assuring adequate public participation in the process of reviewing site-specific risk analyses.

To ensure that affected sources which choose to comply with the alternative health-based emission standards continue to comply with those standards after the initial compliance demonstration, specified assessment parameters (*e.g.*, HCl and/or manganese emission rate, boiler heat output, etc.) must be included in their title V permit as enforceable requirements. Draft permits and permit applications must be made available to the public from the State or local agency responsible for issuing the permit, or in the case where EPA is issuing the permit, from the EPA regional office. Members of the public may request that the State or local agency include them on their public notice mailing list, thus providing the public the opportunity to review the appropriateness of these requirements. Every proposed title V permit has a 30-day public comment period and a 45-day EPA review period. If EPA does not object to the permit, any member of the public may petition EPA to object to the permit within 60 days of the end of the EPA review period.

*Comment:* A commenter contended that exempting HCl emissions from control is inappropriate, particularly since EPA proposed HCl as a surrogate measure for all the inorganic HAP emitted by this source category. Hence, an exemption that excluded HCl emission points from control requirements would also exclude emissions of all the other inorganic HAP that would likely include hydrogen cyanide and hydrogen fluoride.

*Response:* Facilities attempting to utilize the health-based compliance alternative for HCl will not be required to evaluate emissions of other inorganic HAP except for chlorine. We conducted an assessment of boiler emissions and determined that, of the acid gas HAP controlled by scrubbing technology, chlorine is responsible for the great majority of risk and HCl is responsible for the next largest portion of the total risk. The contributions of other HAP, including hydrogen fluoride, to the total risk were negligible. Therefore, facilities attempting to demonstrate eligibility for the health-based compliance alternative for HCl, either by conducting a lookup table analysis or by conducting a site-specific compliance demonstration, must include emission rates of chlorine and HCl from their boilers. We do not expect hydrogen cyanide emissions from boilers covered under the final rule.

*Comment:* Commenters stated that the proposal does not address ecological risk that may result from uncontrolled HAP emissions, especially in those areas with sensitive habitats but few people nearby to be exposed and that EPA provided inadequate discussion of how environmental risks will be evaluated.

*Response:* To identify HAP with potential to cause multimedia and/or environmental effects, the EPA has identified HAP with significant potential to persist in the environment and to bioaccumulate. This list does not include HCl or manganese which are the only HAP with health-based compliance alternatives in the final rule. Additionally, a screening level analysis conducted by the EPA indicates that acute impacts of these HAP from industrial boiler facilities are highly unlikely. For these reasons we do not believe that emissions of HCl or manganese from industrial boiler facilities will pose a significant risk to the environment and facilities attempting to comply with the health-based alternatives for these HAP are not required to perform an ecological assessment.

## V. Impacts of the Final Rule

### *A. What Are the Air Impacts?*

Nationwide emissions of selected HAP (*i.e.*, HCl, hydrogen fluoride, lead, and nickel) will be reduced by 58,500 tpy for existing units and 73 tpy for new units. Depending on the number of facilities demonstrating eligibility for the health-based compliance alternatives, the total HAP reduction for existing units could be 50,600 tpy. Emissions of HCl will be reduced by 42,000 tpy for existing units and 72 tpy for new units. Depending on the number of facilities demonstrating eligibility for the health-based compliance alternatives, the total HCl emissions reduction for existing units could be 36,400 tpy. Emissions of mercury will be reduced by 1.9 tpy for existing units and 0.006 tpy for new units. Emissions of PM will be reduced by 565,000 tpy for existing units and 480 tpy for new units. Depending on the number of facilities demonstrating eligibility for the health-based compliance alternatives, the total PM emissions reduction for existing units could be 547,000 tpy. Emissions of total selected nonmercury metals (*i.e.*, arsenic, beryllium, cadmium, chromium, lead, manganese, nickel, and selenium) will be reduced by 1,100 tpy for existing units and will be reduced by 1.4 tpy for new units. Depending on the number of facilities demonstrating eligibility for the health-based compliance alternatives, the total nonmercury metals emissions reduction for existing units could be 950 tpy. In addition, emissions of sulfur dioxide ($SO_2$) are established to be reduced by 113,000 tpy for existing sources and 110 tpy for new sources. Depending on the number of facilities demonstrating eligibility for the health-based compliance alternatives, the total $SO_2$ emissions reduction for existing units could be 49,000 tpy.

As noted above, use of the health-based compliance alternatives by eligible facilities will affect reductions in HAP, PM (and total non-mercury metals that are generally controlled along with PM), and $SO_2$. Nevertheless, our analysis indicates that the difference in emissions of HCl and manganese with and without the compliance alternatives will not affect health risks because the compliance alternative is available only to those facilities that demonstrate that their emissions pose little risks. Emissions of PM and $SO_2$ will still be reduced by the implementation of other provisions of the Clean Air Act, such as attainment of the health-based National Ambient Air Quality Standards, which include mechanisms to control such emissions.

A discussion of the methodology used to estimate emissions and emissions reductions is presented in ‘‘Estimation of Baseline Emissions and Emissions Reductions for Industrial, Commercial, and Institutional Boilers and Process Heaters’’ in the docket. To estimate the potential impacts of the health-based compliance alternatives, we performed a preliminary ‘‘rough’’ assessment of the large solid fuel subcategory to determine the extent to which facilities might become eligible for the health-based compliance alternatives. Based on the results of this rough assessment, 448 coal-fired boilers could potentially be eligible for the HCl compliance alternative and 386 biomass-fired boilers could be potentially eligible for the TSM compliance alternative.

### *B. What Are the Water and Solid Waste Impacts?*

The EPA estimates the additional water usage that would result from the MACT floor level of control to be 110 million gallons per year for existing sources and 0.6 million gallons per year for new sources. In addition to the increased water usage, an additional 3.7 million gallons per year of wastewater will be produced for existing sources and 0.6 million gallons per year for new sources. The costs of treating the additional wastewater are $18,000 for existing sources and $2,300 for new sources, in advance of any facility demonstrating eligibility for the health-based compliance alternatives. These costs are accounted for in the control costs estimates.

The EPA estimates the additional solid waste that would result from the MACT floor level of control to be 102,000 tpy for existing sources and 1 tpy for new sources. The estimated costs of handling the additional solid waste generated are $1.5 million for existing sources and $17,000 for new sources, in advance of any facility demonstrating eligibility for the health-based compliance alternatives. These costs are also accounted for in the control costs estimates.

A discussion of the methodology used to estimate impacts is presented in ‘‘Estimation of Impacts for Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP’’ in the docket.

### *C. What Are the Energy Impacts?*

The EPA expects an increase of approximately 1,130 million kilowatt hours (kWh) in national annual energy usage as a result of the final rule, in advance of any facility demonstrating eligibility for the health-based compliance alternatives. Of this amount, 1,120 million kWh is estimated from existing sources and 13 million kWh is estimated from new sources. The increase results from the electricity required to operate control devices installed to meet the final rule, such as wet scrubbers and fabric filters.

*D. What Are the Control Costs?*

To estimate the national cost impacts of the final rule for existing sources, EPA developed several model boilers and process heaters and determined the cost of control equipment for these model boilers. The EPA assigned a model boiler or heater to each existing unit in the database based on the fuel, size, design, and current controls. The analysis considered all air pollution control equipment currently in operation at existing boilers and process heaters. Model costs were then assigned to all existing units that could not otherwise meet the proposed emission limits. The resulting total national cost impact of the final rule is $1,790 million in capital expenditures and $860 million per year in total annual costs. Depending on the number of facilities demonstrating eligibility for the health-based compliance alternatives, these costs could be $1,440 million in capital expenditures and $690 million per year in total annual costs. The total capital and annual costs include costs for testing, monitoring, and recordkeeping and reporting. Costs include testing and monitoring costs, but not recordkeeping and reporting costs.

Using Department of Energy projections on fuel expenditures, EPA estimated the number of additional boilers that could be potentially constructed. The resulting total national cost impact of the final rule in the 5th year is $58 million in capital expenditures and $18.6 million per year in total annual costs, in advance of any facility demonstrating eligibility for the health-based provisions. Costs are mainly for testing and monitoring.

A discussion of the methodology used to estimate cost impacts is presented in ''Methodology for Estimating Control Cost for the Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants'' in the docket.

*E. What Are the Economic Impacts?*

The economic impact analysis shows that the expected price increase for output in the 40 affected industries would be no more than 0.04 percent as a result of the final rule for industrial boilers and process heaters. The expected change in production of affected output is a reduction of only 0.03 percent or less in the same industries. In addition, impacts to affected energy markets show that prices of petroleum, natural gas, electricity and coal should increase by no more than 0.05 percent as a result of implementation of the final rule, and output of these types of energy should decrease by no more than 0.01 percent. These impacts are generated in advance of any facility demonstrating eligibility for the health-based compliance alternatives. Depending on the number of affected facilities demonstrating eligibility for the health-based compliance alternatives, these impacts on product prices could fall to a 0.03 percent increase, and a decrease in output of the energy types mentioned previously of less than 0.01 percent. Therefore, it is likely that there is no adverse impact expected to occur for those industries that produce output affected by the final rule, such as lumber and wood products, chemical manufacturers, petroleum refining, and furniture manufacturing.

*F. What Are the Social Costs and Benefits of the Final Rule?*

Our assessment of costs and benefits of the final rule is detailed in the ''Regulatory Impact Analysis for the Final Industrial, Commercial, and Institutional Boilers and Process Heaters MACT.'' The Regulatory Impact Analysis (RIA) is located in the Docket.

It is estimated that 3 years after implementation of the final rule, HAP will be reduced by 58,500 tpy (53,200 megagrams per year (Mg/yr)) due to reductions in arsenic, beryllium, HCl, and several other HAP from existing affected emission sources. Of these reductions, 42,000 tpy (38,200 Mg/yr) are of HCl. In addition to these reductions, there are 73 tpy (66 Mg/yr) of HAP reductions expected from new sources. Of these reductions, virtually all of them are of HCl. The health effects associated with these HAP are discussed earlier in this preamble. While it is beneficial to society to reduce these HAP, we are unable to quantify and provide a monetized estimate of the benefits at this time.

Despite our inability to quantify and provide monetized benefit estimates from HAP reductions, it is possible to derive rough estimates for one of the more important benefit categories, *i.e.*, the potential number of cancer cases avoided and cancer risk reduced as a result of the imposition of the MACT level of control on this source category. Our analysis suggests that imposition of the MACT level of control would reduce cancer cases at worst case baseline assumptions by possibly tens of cases per year, on average, starting some years after implementation of the final rule. This risk reduction estimate is uncertain, is likely to overestimate benefits, and should be regarded as an extremely rough estimate. Furthermore, the estimate should be viewed in the context of the full spectrum of unquantified noncancer effects associated with the HAP reductions. Noncancer effects associated with the HAP are presented earlier in this preamble.

The control technologies used to reduce the level of HAP emitted from affected sources are also expected to reduce emissions of PM ($PM_{10}$, $PM_{2.5}$), and sulfur dioxide ($SO_2$). It is estimated that $PM_{10}$ emissions reductions total approximately 562,000 tpy (510,000 Mg/yr), $PM_{2.5}$ emissions reductions total approximately 159,000 tpy (145,000 Mg/yr), and $SO_2$ emissions reductions total approximately 113,000 tpy (102,670 Mg/yr). These estimated reductions occur from existing sources in operation 3 years after the implementation of the requirements of the final rule and are expected to continue throughout the life of the sources.

In general, exposure to high concentrations of PM may aggravate existing respiratory and cardiovascular disease including asthma, bronchitis and emphysema, especially in children and the elderly. $SO_2$ is also a contributor to acid deposition, or acid rain, which causes acidification of lakes and streams and can damage trees, crops, historic buildings and statues. Exposure to $PM_{2.5}$ can lead to decreased lung function, and alterations in lung tissue and structure and in respiratory tract defense mechanisms which may then lead to, increased respiratory symptoms and disease, or in more severe cases, premature death or increased hospital admissions and emergency room visits. Children, the elderly, and people with cardiopulmonary disease, such as asthma, are most at risk from these health effects. Fine PM can also form a haze that reduces the visibility of scenic areas, can cause acidification of water bodies, and have other impacts on soil, plants, and materials. As $SO_2$ emissions transform into PM, they can lead to the same health and welfare effects listed above.

For $PM_{10}$ and $PM_{2.5}$ (including $SO_2$ contributions to ambient concentrations of $PM_{2.5}$), we provide a monetary estimate for the benefits associated with the reduction in emissions associated with the final rule. To do so, we conducted an air quality assessment to determine the change in ambient concentrations of $PM_{10}$ and $PM_{2.5}$ that result from reductions of PM and $SO_2$ at existing affected facilities. Unfortunately, our data are not able to define the exact location of the reductions for every affected boiler and process heater. Because of this limitation, the benefits assessment is conducted in two phases. First, an air quality analysis was conducted for emissions reductions from those emissions sources that have an known link to a specific control device, which represents approximately 50 percent of the total emissions reductions mentioned above. Using this subset of information, we determined the air quality change nationwide. The results of the air quality assessment served as input to a model that estimates the total monetary value of benefits of the health effects listed above. Total benefits associated with this portion of the analysis (in phase one) are $8.2 billion in the year 2005 (presented in 1999 dollars).

In the second phase of our analysis, for those emissions reductions from affected sources that do not have a known link to a specific control device, the results of the air quality analysis in phase one serve as a reasonable approximation of air quality changes to transfer to the remaining emissions reductions of the final rule. Because there is not a reasonable way to apportion the total benefits of the combined impact of the PM and $SO_2$ reductions from the air quality and benefit analyses completed above, we performed two additional air quality analyses. One analysis was performed to evaluate the impact on air quality of the PM reductions alone (holding $SO_2$ unchanged), and one to evaluate the impact on air quality from the $SO_2$ reductions alone (holding PM unchanged). With independent PM and $SO_2$ air quality assessments, we can determine the total benefit associated with each component of total pollutant reductions. The total benefit associated with the PM and $SO_2$ reductions with unspecified location (in phase two) are $7.9 billion.

The benefit estimates derived from the air quality modeling in the first phase of our analysis uses an analytical structure and sequence similar to that used in the benefits analyses for the proposed Nonroad Diesel rule and proposed Integrated Air Quality Rule (IAQR) and in the ''section 812 studies'' analysis of the total benefits and costs of the Clean Air Act. We used many of the same models and assumptions used in the Nonroad Diesel and IAQR analyses as well as other Regulatory Impact Analyses (RIAs) prepared by the Office of Air and Radiation. By adopting the major design elements, models, and assumptions developed for the section 812 studies and other RIAs, we have largely relied on methods which have already received extensive review by the independent Science Advisory Board (SAB), the National Academies of Sciences, by the public, and by other federal agencies.

The benefits transfer method used in the second phase of the analysis is similar to that used to estimate benefits at the proposal of the rule, and in the proposed Reciprocating Internal Combustion Engines NESHAP. A similar method has also been used in recent benefits analyses for the proposed Nonroad Large Spark-Ignition Engines and Recreational Engines standards (67 FR 68241, November 8, 2002).

The sum of benefits from the two phases of analysis provide an estimate of the total benefits of the rule. Total benefits of the final rule are approximately $16.3 billion (1999$). This economic benefit is associated with approximately 2,270 avoided premature mortalities, 5,100 avoided cases of chronic bronchitis, thousands of avoided hospital and emergency room visits for respiratory and cardiovascular diseases, tens of thousands of avoided days with respiratory symptoms, and millions of avoided work loss and restricted activity days. This estimate is generated in advance of any facility demonstrating eligibility for the health-based compliance alternatives.

Every benefit-cost analysis examining the potential effects of a change in environmental protection requirements is limited, to some extent, by data gaps, limitations in model capabilities (such as geographic coverage), and uncertainties in the underlying scientific and economic studies used to configure the benefit and cost models. Deficiencies in the scientific literature often result in the inability to estimate changes in health and environmental effects. Deficiencies in the economics literature often result in the inability to assign economic values even to those health and environmental outcomes that can be quantified. While these general uncertainties in the underlying scientific and economics literatures are discussed in detail in the RIA and its supporting documents and references, the key uncertainties which have a bearing on the results of the benefit-cost analysis of today's action are the following:

1. The exclusion of potentially significant benefit categories (*e.g.*, health and ecological benefits of reduction in hazardous air pollutants emissions);
2. Errors in measurement and projection for variables such as population growth;
3. Uncertainties in the estimation of future year emissions inventories and air quality;
4. Uncertainties associated with the extrapolation of air quality monitoring data to some unmonitored areas required to better capture the effects of the standards on the affected population;
5. Variability in the estimated relationships of health and welfare effects to changes in pollutant concentrations; and
6. Uncertainties associated with the benefit transfer approach.
7. Uncertainties in the size of the effect estimates linking air pollution and health endpoints.
8. Uncertainties about relative toxicity of different components within the complex mixture.

Despite these uncertainties, we believe the benefit-cost analysis provides a reasonable indication of the expected economic benefits of the final rule under a given set of assumptions.

Based on estimated compliance costs (control + administrative costs associated with Paperwork Reduction Act requirements associated with the rule and predicted changes in the price and output of electricity), the estimated annualized social costs of the Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP are $863 million (1999$). Depending on the number of affected facilities demonstrating eligibility for the health-based compliance alternatives, these annualized social costs could fall to $746 million. Social costs are different from compliance costs in that social costs take into account the interactions between affected producers and the consumers of affected products in response to the imposition of the compliance costs.

As explained above, we estimate $16.3 billion in benefits from the final rule, compared to $863 million in costs. It is important to put the results of this analysis in the proper context. The large benefit estimate is not attributable to reducing human and environmental exposure to the HAPs that are reduced by this rule. It arises from ancillary reductions in PM and $SO_2$ that result from controls aimed at complying with the NESHAP. Although consideration of ancillary benefits is reasonable, we note that these benefits are not uniquely attributable to the regulation. The Agency believes nonetheless that the key rationale for controlling arsenic, beryllium, HCl, and the other HAPs associated with this rule is to reduce public and environmental exposure to these HAPs, thereby reducing risk to public health and wildlife. Although the available science does not support quantification of these benefits at this time, the Agency believes the qualitative benefits are large enough to justify substantial investment in these emission reductions.

It should be recognized, however, that this analysis does not account for many of the potential benefits that may result from these actions. Thus, our estimate of total benefits also includes a ''B'' to represent those additional health and environmental benefits which could not be expressed in quantitative incidence and/or economic value terms. The net benefits would be greater if all the benefits of the other pollutant reductions could be quantified. Notable omissions to the net benefits include all benefits of HAP reductions, including reduced cancer incidences, toxic morbidity effects, and cardiovascular and CNS effects, and all welfare effects from reduction of ambient PM and $SO_2$. A full appreciation of the overall economic consequences of the industrial boiler and process heater standards requires consideration of all benefits and costs expected to result from the final rule, not just those benefits and costs that could be expressed here in dollar terms. A full listing of the benefit categories that could not be quantified or monetized in our base estimate are provided in Table 2 of this preamble.

TABLE 2.—UNQUANTIFIED BENEFIT CATEGORIES

| | Unquantified benefit categories associated with HAP eductions | Unquantified benefit categories associated with PM eductions |
|---|---|---|
| Health Categories | —Airway responsiveness<br>—Pulmonary inflammation<br>—Susceptibility to respiratory infection<br>—Acute inflammation and respiratory cell damage<br>—Chronic respiratory damage/Premature aging of lungs<br>—Emergency room visits for asthma | —Changes in pulmonary function.<br>—Morphological changes. Altered host defense mechanisms.<br>—Other chronic respiratory disease.<br>—Emergency room visits for asthma.<br>—Emergency visits for non-asthma respiratory and cardiovascular causes.<br>—Lower and upper respiratory systems.<br>—Acute bronchitis.<br>—Shortness of breath. |
| Welfare Categories | —Ecosystem and vegetation effects<br>—Damage to urban ornamentals (e.g., grass, flowers, shrubs, and trees in urban areas).<br>—Commercial field crops<br>—Fruit and vegetable crops<br>—Yields of tree seedlings, commercial and non-commercial forests.<br>—Damage to ecosystems<br>—Materials damage | —School absence rates.<br>—Materials damage.<br>—Damage to ecosystems (e.g., acid sulfate deposition).<br>—Nitrates in drinking water.<br>—Visibility in recreational and residential areas. |

Using the results of the benefit analysis, we can use benefit-cost comparison (or net benefits) as another tool to evaluate the reallocation of society's resources needed to address the pollution externality created by the operation of industrial boilers and process heaters. The additional costs of internalizing the pollution produced at major sources of emissions from industrial boilers and process heaters are compared to the improvement in society's well-being from a cleaner and healthier environment. Comparing benefits of the final rule to the costs imposed by alternative ways to control emissions optimally identifies a strategy that results in the highest net benefit to society. In the final rule, we include only one option, the minimal level of control mandated by the CAA, or the MACT floor. Other alternatives that lead to higher levels of control (or beyond-the-floor alternatives) lead to higher estimates of benefits net of costs, but also lead to additional economic impacts, including more substantial impacts to small entities. For more details, please refer to the RIA for the final rule.

Based on estimated compliance costs associated with the final rule and the predicted change in prices and production in the affected industries, the estimated annualized social costs of the final rule are $863 million (1999 dollars). This estimate of social cost is generated in advance of any facility demonstrating eligibility for the health-based compliance alternatives. Depending on the number of affected facilities demonstrating eligibility for the health-based compliance alternatives, these annualized social costs could fall to $746 million. Social costs are different from compliance costs in that social costs take into account the interactions of consumers and producers of affected products in response to the imposition of the compliance costs. Therefore, the Agency's estimate of monetized benefits net of costs is $15.4 billion + B (1999 dollars) in 2005.

## VI. Statutory and Executive Order Reviews

### *A. Executive Order 12866: Regulatory Planning and Review*

Under Executive Order 12866 (58 FR 51735, October 4, 1993), the EPA must determine whether a regulatory action is ''significant'' and, therefore, subject to review by the OMB and the requirements of the Executive Order. The Executive Order defines ''significant regulatory action'' as one that is likely to result in a rule that may:

(1) Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities;

(2) Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;

(3) Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs, or the rights and obligation of recipients thereof; or

(4) Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

Pursuant to the terms of Executive Order 12866, the EPA has determined that the final rule is a ''significant regulatory action'' because it has an annual effect on the economy of over $100 million. As such, the final rule was submitted to OMB for review.

### *B. Paperwork Reduction Act*

The information collection requirements in the final rule have been submitted for approval to the Office of Management and Budget (OMB) under the *Paperwork Reduction Act*, 44 U.S.C. 3501 *et seq.* The information collection requirements are not enforceable until OMB approves them.

The information requirements are based on notification, recordkeeping, and reporting requirements in the NESHAP General Provisions (40 CFR part 63, subpart A), which are mandatory for all operators subject to national emission standards. These recordkeeping and reporting requirements are specifically authorized by section 114 of the CAA (42 U.S.C. 7414). All information submitted to EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to Agency policies set forth in 40 CFR part 2, subpart B.

The final rule requires maintenance inspections of the control devices, but does not require any notifications or reports beyond those required by the General Provisions. The recordkeeping requirements require only the specific information needed to determine compliance.

The annual monitoring, reporting, and recordkeeping burden for this collection (averaged over the first 3 years after the effective date of the final rule) is estimated to be $91 million. This includes 1.2 million labor hours per year at a total labor cost of $67 million per year, and total non-labor capital costs of $24 million per year. This estimate includes a one-time performance test, semiannual excess emission reports, maintenance inspections, notifications, and recordkeeping. The total burden for the Federal government (averaged over the first 3 years after the effective date of the final rule) is estimated to be 346,000 hours per year at a total labor cost of $14 million per year. Table 3 of this preamble shows the average annualized burden for monitoring, reporting, and recordkeeping for each subcategory.

TABLE 3.—SUMMARY OF THE AVERAGE REPORTING AND RECORDKEEPING COSTS

| Subcategory | Total labor costs ($) | Total capital costs ($) | Total costs ($) |
|---|---|---|---|
| Large Solid Fuel Units | 56,253,000 | 12,488,000 | 68,741,000 |
| Limited Use Solid Fuel Units | 2,565,000 | 2,267,000 | 4,832,000 |
| Small Solid Fuel Units | 627,000 | 111,000 | 738,000 |
| Large Liquid Fuel Units | 498,000 | 491,000 | 989,000 |
| Limited Use Liquid Fuel Units | 214,000 | 264,000 | 478,000 |
| Small Liquid Fuel Units | 442,000 | 0 | 442,000 |
| Large Gaseous Fuel Units | 3,673,000 | 6,615,000 | 10,288,000 |
| Limited Use Gaseous Fuel Units | 663,000 | 1,209,000 | 1,872,000 |
| Small Gaseous Fuel Units | 2,413,000 | 0 | 2,413,000 |

Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations are listed in 40 CFR part 9. When this ICR is approved by OMB, the Agency will publish a technical amendment to 40 CFR part 9 in the **Federal Register** to display the OMB control number for the approved information collection requirements contained in this final rule.

The EPA requested comments on the need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including through the use of automated collection techniques.

### *C. Regulatory Flexibility Act*

The EPA has determined that it is not necessary to prepare a regulatory flexibility analysis in connection with the final rule. We have also determined that the final rule will not have a significant impact on a substantial number of small entities.

For purposes of assessing the impacts of the final rule on small entities, small entity is defined as:

(1) A small business according to Small Business Administration size standards by the North American Industry Classification System (NAICS) category of the owning entity. The range of small business size standards for the 40 affected industries ranges from 500 to 1,000 employees, except for petroleum refining and electric utilities. In these latter two industries, the size standard is 1,500 employees and a mass throughput of 75,000 barrels/day or less, and 4 million kilowatt-hours of production or less, respectively;

(2) A small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and

(3) A small organization that is any not-for-profit enterprise that is independently owned and operated and is not dominant in its field.

After considering the economic impact of the final rule on small entities, we have determined that the final rule will not have a significant economic impact on a substantial number of small entities. Based on SBA size definitions for the affected industries and reported sales and employment data, EPA identified 185 of the 576 entities, or 32 percent, owning affected facilities as small entities. Although small entities represent 32 percent of the entities within the source category, they are expected to incur only 4 percent of the total compliance costs of $862.7 million (1998 dollars). There are only ten small entities with compliance costs equal to or greater than 3 percent of their sales. In addition, there are only 24 small entities with cost-to-sales ratios between 1 and 3 percent.

An economic impact analysis was performed to estimate the changes in product price and production quantities for the final rule. As mentioned in the summary of economic impacts earlier in this preamble, the estimated changes in prices and output for affected entities is no more than 0.05 percent. For more information, consult the docket for the final rule.

It should be noted that these small entity impacts are in advance of any facility demonstrating eligibility for the health-based compliance alternatives. Depending on the number of affected facilities demonstrating eligibility for the health-based compliance alternatives, the estimated small entity impacts could fall to eight small entities with compliance costs equal to or greater than 3 percent of their sales, and 14 small entities with compliance costs between 1 and 3 percent of their sales.

The final rule will not have a significant economic impact on a substantial number of small entities as a result of several decisions EPA made regarding the development of the rule, which resulted in limiting the impact of the rule on small entities. First, as mentioned earlier in this preamble, EPA identified small units (heat input of 10 MMBtu/hr or less) and limited use boilers (operate less than 10 percent of the time) as separate subcategories different from large units. Many small and limited use units are located at small entities. As also discussed earlier, the results of the MACT floor analysis for these subcategories of existing sources was that no MACT floor could be identified except for the limited use solid fuel subcategory, which is less stringent than the MACT floor for large units. Furthermore, the results of the beyond-the-floor analysis for these subcategories indicated that the costs would be too high to consider them feasible options. Consequently, the final rule contains no emission limitations for any of the existing small and limited use subcategories except the existing limited use solid fuel subcategory. In addition, the alternative metals emission limit resulted in minimizing the impacts on small entities since some of the potential entities burning a fuel containing very little metals are small entities.

### *D. Unfunded Mandates Reform Act of 1995*

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Public Law 104–4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and tribal governments and the private sector. Under section 202 of the UMRA, we generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with ''Federal mandates'' that may result in expenditures to State, local, and tribal governments, in the aggregate, or to the private sector, of $100 million or more in any 1 year. Before promulgating a rule for which a written statement is needed, section 205 of the UMRA generally requires us to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective or least burdensome alternative that achieves the objectives of the rule. The provisions of section 205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows us to adopt an alternative other than the least costly, most cost-effective or least burdensome alternative if the EPA Administrator publishes with the final rule an explanation why that alternative was not adopted. Before we establish any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, we must develop a small government agency plan under section 203 of the UMRA. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of regulatory promulgation with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

We determined that the final rule contains a Federal mandate that may result in expenditures of $100 million or more for State, local, and Tribal governments, in the aggregate, or the private sector in any 1 year. Accordingly, we have prepared a written statement (titled ''Unfunded Mandates Reform Act Analysis for the Industrial Boilers and Process Heaters NESHAP)'' under section 202 of the UMRA, which is summarized below.

#### Statutory Authority

As discussed in this preamble, the statutory authority for the final rulemaking is section 112 of the CAA. Title III of the CAA Amendments was enacted to reduce nationwide air toxic emissions. Section 112(b) of the CAA lists the 188 chemicals, compounds, or groups of chemicals deemed by Congress to be HAP. These toxic air pollutants are to be regulated by NESHAP.

Section 112(d) of the CAA directs us to develop NESHAP, which require existing and new major sources to control emissions of HAP using MACT based standards. The final rule applies to all industrial, commercial, and institutional boilers and process heaters located at major sources of HAP emissions.

In compliance with section 205(a) of the UMRA, we identified and considered a reasonable number of regulatory alternatives. Additional information on the costs and environmental impacts of these regulatory alternatives is presented in the docket.

The regulatory alternative upon which the final rule is based represents the MACT floor for industrial boilers and process heaters and, as a result, it is the least costly and least burdensome alternative.

#### Social Costs and Benefits

The regulatory impact analysis prepared for the final rule including the EPA's assessment of costs and benefits, is detailed in the ''Regulatory Impact Analysis for the Industrial Boilers and Process Heaters MACT'' in the docket. Based on estimated compliance costs associated with the final rule and the predicted change in prices and production in the affected industries, the estimated social costs of the final rule are $863 million (1999 dollars). Depending on the number of affected facilities demonstrating eligibility for the health-based compliance alternatives, these annualized social costs could fall to $746 million.

It is estimated that 5 years after implementation of the final rule, HAP will be reduced by 58,500 tpy due to reductions in arsenic, beryllium, dioxin, hydrochloric acid, and several other HAP from industrial boilers and process heaters. Studies have determined a relationship between exposure to these HAP and the onset of cancer, however, there are some questions remaining on how cancers that may result from exposure to these HAP can be quantified in terms of dollars. Therefore, the EPA is unable to provide a monetized estimate of the benefits of the HAP reduced by the final rule at this time. However, there are significant reductions in PM and in $SO_2$ that occur. Reductions of 560,000 tons of PM with a diameter of less than or equal to 10 micrometers ($PM_{10}$), 159,000 tons of PM with a diameter of less than or equal to 2.5 micrometers ($PM_{2.5}$), and 112,000 tons of $SO_2$ are expected to occur. These reductions occur from existing sources in operation 5 years after the implementation of the regulation and are expected to continue throughout the life of the affected sources. The major health effect that results from these PM and $SO_2$ emissions reductions is a reduction in premature mortality. Other health effects that occur are reductions in chronic bronchitis, asthma attacks, and work-lost days (*i.e.,* days when employees are unable to work).

While we are unable to monetize the benefits associated with the HAP emissions reductions, we are able to monetize the benefits associated with the PM and $SO_2$ emissions reductions. For $SO_2$ and PM, we estimated the benefits associated with health effects of PM, but were unable to quantify all categories of benefits (particularly those associated with ecosystem and environmental effects). Unquantified benefits are noted with ''B'' in the estimates presented below. Our primary estimate of the monetized benefits in 2005 associated with the implementation of the proposed alternative is $16.3 billion + B (1999 dollars). This estimate is about $15.3 billion + B (1999 dollars) higher than the estimated social costs shown earlier in this section. These benefit estimates are in advance of any facility demonstrating eligibility for the health-based compliance alternatives. Depending on the number of affected facilities demonstrating eligibility for the health-based compliance alternatives, the benefit estimate presuming the health-based compliance alternatives is $14.5 billion + B, which is $1.7 billion lower than the estimate for the final rule. This estimate is $13.8 billion + B higher than the estimated social costs presuming the health-based compliance alternatives. The general approach to calculating monetized benefits is discussed in more detail earlier in this preamble. For more detailed information on the benefits estimated for the final rule, refer to the RIA in the docket.

### Future and Disproportionate Costs

The Unfunded Mandates Act requires that we estimate, where accurate estimation is reasonably feasible, future compliance costs imposed by the rule and any disproportionate budgetary effects. Our estimates of the future compliance costs of the final rule are discussed previously in this preamble.

We do not feel that there will be any disproportionate budgetary effects of the final rule on any particular areas of the country, State or local governments, types of communities (*e.g.,* urban, rural), or particular industry segments. This is true for the 257 facilities owned by 54 different government bodies, and this is borne out by the results of the ''Economic Impact Analysis of the Industrial Boilers and Process Heaters NESHAP,'' the results of which are discussed previously in this preamble.

### Effects on the National Economy

The Unfunded Mandates Act requires that we estimate the effect of the final rule on the national economy. To the extent feasible, we must estimate the effect on productivity, economic growth, full employment, creation of productive jobs, and international competitiveness of the U.S. goods and services, if we determine that accurate estimates are reasonably feasible and that such effect is relevant and material.

The nationwide economic impact of the final rule is presented in the ''Economic Impact Analysis for the Industrial Boilers and Process Heaters MACT'' in the docket. This analysis provides estimates of the effect of the final rule on some of the categories mentioned above. The results of the economic impact analysis are summarized previously in this preamble. The results show that there will be little impact on prices and output from the affected industries, and little impact on communities that may be affected by the final rule. In addition, there should be little impact on energy markets (in this case, coal, natural gas, petroleum products, and electricity). Hence, the potential impacts on the categories mentioned above should be minimal.

### Consultation With Government Officials

The Unfunded Mandates Act requires that we describe the extent of the EPA's prior consultation with affected State, local, and tribal officials, summarize the officials' comments or concerns, and summarize our response to those comments or concerns. In addition, section 203 of the UMRA requires that we develop a plan for informing and advising small governments that may be significantly or uniquely impacted by a rule. Although the final rule does not significantly affect any State, local, or Tribal governments, we have consulted with State and local air pollution control officials. We also have held meetings on the final rule with many of the stakeholders from numerous individual companies, environmental groups, consultants and vendors, labor unions, and other interested parties. We have added materials to the docket to document these meetings.

In addition, we have determined that the final rule contains no regulatory requirements that might significantly or uniquely affect small governments. While some small governments may have some sources affected by the final rule, the impacts are not expected to be significant. Therefore, the final rule is not subject to the requirements of section 203 of the UMRA. However, EPA did complete a report containing analyses called for in the UMRA as a response to comments from many municipal utilities regarding the final rule and its potential impacts. This report, ''Unfunded Mandates Reform Act Analysis for the Industrial Boilers and Process Heaters NESHAP,'' is in the docket.

### *E. Executive Order 13132: Federalism*

Executive Order 13132 requires EPA to develop an accountable process to ensure ''meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications.'' ''Policies that have federalism implications'' are defined in the Executive Order to include regulations that have ''substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.

The final rule does not have federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132.

The agency is required by section 112 of the CAA, to establish the standards in the final rule. The final rule primarily affects private industry, and does not impose significant economic costs on State or local governments. The final rule does not include an express provision preempting State or local regulations. Thus, the requirements of section 6 of the Executive Order do not apply to the final rule.

Although section 6 of Executive Order 13132 does not apply to the final rule, we consulted with representatives of State and local governments to enable them to provide meaningful and timely input into the development of the final rule. This consultation took place during the ICCR Federal Advisory Committee Act (FACA) committee meetings where members representing State and local governments participated in developing recommendations for EPA's combustion-related rulemakings, including the final rule. The concerns raised by representatives of State and local governments were considered during the development of the final rule.

In the spirit of Executive Order 13132, and consistent with EPA policy to promote communications between EPA and State and local governments, EPA specifically solicited comment on the final rule from State and local officials.

### *F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments*

Executive Order 13175 (65 FR 67249, November 9, 2000) requires EPA to develop an accountable process to ensure ''meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications.'' The final rule does not have tribal implications, as specified in Executive Order 13175.

The final rule does not significantly or uniquely affect the communities of Indian tribal governments. We do not know of any industrial-commercial-institutional boilers or process heaters owned or operated by Indian tribal governments. However, if there are any, the effect of these rules on communities of tribal governments would not be unique or disproportionate to the effect on other communities. Thus, Executive Order 13175 does not apply to the final rule. The EPA specifically solicited additional comment on the final rule from tribal officials, but received none.

### *G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks*

Executive Order 13045 (62 FR 19885, April 23, 1997) applies to any regulation that: (1) Is determined to be ''economically significant'' as defined under Executive Order 12866, and (2) concerns an environmental health or safety risk that we have reason to believe may have a disproportionate effect on children.

If the regulatory action meets both criteria, the EPA must evaluate the environmental health or safety effects of the planned regulation on children, and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by the EPA.

The EPA interprets Executive Order 13045 as applying only to those regulatory actions that are based on health or safety risks, such that the analysis required under section 5–501 of the Executive Order has the potential to influence the regulation. The final rule is not subject to Executive Order 13045 because it is based on technology performance and not on health or safety risks.

### *H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use*

Executive Order 13211 (66 FR 28355, May 22, 2001) provides that agencies shall prepare and submit to the Administrator of the Office of Information and Regulatory Affairs, Office of Management and Budget, a Statement of Energy Effects for certain actions identified as ''significant energy actions.'' Section 4(b) of Executive Order 13211 defines ''significant energy actions'' as ''any action by an agency (normally published in the **Federal Register**) that promulgates or is expected to lead to the promulgation of a final rule or regulation, including notices of inquiry, advance notices of final rulemaking, and notices of final rulemaking: (1)(i) That is a significant regulatory action under Executive Order 12866 or any successor order, and (ii) is likely to have a significant adverse effect on the supply, distribution, or use of energy; or (2) that is designated by the Administrator of the Office of Information and Regulatory Affairs as a ''significant energy action.'' The final rule is not a ''significant energy action'' because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. The basis for the determination is as follows.

The reduction in petroleum product output, which includes reductions in fuel production, is estimated at only 0.001 percent, or about 68 barrels per day based on 2000 U.S. fuel production nationwide. That is a minimal reduction in nationwide petroleum product output. The reduction in coal production is estimated at only 0.014 percent, or about 3.5 million tpy (or less than 1,000 tons per day) based on 2000 U.S. coal production nationwide. The combination of the increase in electricity usage estimated with the effect of the increased price of affected output yields an increase in electricity output estimated at only 0.012 percent, or about 0.72 billion kilowatt-hours per year based on 2000 U.S. electricity production nationwide. All energy price changes estimated show no increase in price more than 0.05 percent nationwide, and a similar result occurs for energy distribution costs. We also expect that there will be no discernable impact on the import of foreign energy supplies, and no other adverse outcomes are expected to occur with regards to energy supplies. All of the results presented above account for the pass through of costs to consumers, as well as the cost impact to producers. For more information on the estimated energy effects, please refer to the economic impact analysis for the final rule. The analysis is available in the public docket. It should be noted that these energy impact estimates are in advance of any facility demonstrating eligibility for the health-based compliance alternatives.

Depending on the number of affected facilities demonstrating eligibility for the health-based compliance alternatives, the reduction in petroleum product output, which includes reductions in fuel production, could fall to 65 barrels per day, or only 0.001 percent. The reduction in coal production could fall to only 0.010 percent, or about 2.5 million tpy based on 2000 U.S. coal production nationwide. The combination of the increase in electricity usage estimated with the effect of the increased price of affected output could yield an increase in electricity output could fall to only 0.0067 percent, or about 0.40 billion kilowatt-hours per year based on 2000 U.S. electricity production nationwide. All energy price changes estimated could now fall to increases of no more than 0.04 percent nationwide, and a similar result occurs for energy distribution costs. There should be no discernable impact on import of foreign energy supplies, and no other adverse outcomes are expected to occur with regards to energy supplies. All of the results presented with presumption of the health-based compliance alternatives also account for the pass through of costs to consumers as well as the cost impact to producers.

Therefore, we conclude that the final rule when implemented is not likely to have a significant adverse effect on the supply, distribution, or use of energy.

### *I. National Technology Transfer and Advancement Act*

Section 12(d) of the National Technology Transfer and Advancement Act (NTTAA) of 1995 (Pub. L. 104–113; 15 U.S.C. 272 note) directs the EPA to use voluntary consensus standards in their regulatory and procurement activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (*e.g.*, materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. The NTTAA directs EPA to provide Congress, through annual reports to the OMB, with explanations when an agency does not use available and applicable voluntary consensus standards.

The final rule involves technical standards. The EPA cites the following standards in the final rule: EPA Methods 1, 2, 2F, 2G, 3A, 3B, 4, 5, 5D, 17, 19, 26, 26A, 29 of 40 CFR part 60. Consistent with the NTTAA, EPA conducted searches to identify voluntary consensus standards in addition to these EPA methods. No applicable voluntary consensus standards were identified for EPA Methods 2F, 2G, 5D, and 19. The search and review results have been documented and are placed in the docket for the final rule.

The three voluntary consensus standards described below were identified as acceptable alternatives to EPA test methods for the purposes of the final rule.

The voluntary consensus standard ASME PTC 19–10–1981–Part 10, ''Flue and Exhaust Gas Analyses,'' is cited in the final rule for its manual method for measuring the oxygen, carbon dioxide, and carbon monoxide content of exhaust gas. This part of ASME PTC 19–10–1981–Part 10 is an acceptable alternative to Method 3B.

The voluntary consensus standard ASTM D6522–00, ''Standard Test Method for the Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers and Process Heaters Using Portable Analyzers'' is an acceptable alternative to EPA Methods 3A and 10 for identifying carbon monoxide and oxygen concentrations for the final rule when the fuel is natural gas.

The voluntary consensus standard ASTM Z65907, ''Standard Method for Both Speciated and Elemental Mercury Determination,'' is an acceptable alternative to EPA Method 29 (portion for mercury only) for the purpose of the final rule. This standard can be used in the final rule to determine the mercury concentration in stack gases for boilers with rated heat input capacities of greater than 250 MMBtu per hour.

In addition to the voluntary consensus standards EPA uses in the final rule, the search for emissions measurement procedures identified 15 other voluntary consensus standards. The EPA determined that 13 of these 15 standards identified for measuring emissions of the HAP or surrogates subject to the emission standards were impractical alternatives to EPA test methods for the purposes of the final rule. Therefore, EPA does not intend to adopt these standards for this purpose. (See Docket ID No. OAR–2002–0058 for further information on the methods.)

Two of the 15 voluntary consensus standards identified in this search were not available at the time the review was conducted for the purposes of the final rule because they are under development by a voluntary consensus body: ASME/BSR MFC 13M, ''Flow Measurement by Velocity Traverse,'' for EPA Method 2 (and possibly 1); and ASME/BSR MFC 12M, ''Flow in Closed Conduits Using Multiport Averaging Pitot Primary Flowmeters,'' for EPA Method 2.

Section 63.7520 and Tables 4A through 4D of the final rule list the EPA testing methods. Under § 63.7(f) and § 63.8(f) of subpart A, 40 CFR part 63, of the General Provisions, a source may apply to EPA for permission to use alternative test methods or alternative monitoring requirements in place of any of the EPA testing methods, performance specifications, or procedures.

### *J. Congressional Review Act*

The Congressional Review Act, 5 U.S.C. 801, *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. The EPA will submit a report containing the final rule and other required information to the United States Senate, the United States House of Representatives, and the Comptroller General of the United States prior to publication of the final rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is a ''major rule'' as defined by 5 U.S.C. section 804(2). The rule will be effective on November 12, 2004.

### List of Subjects in 40 CFR Part 63

Environmental protection, Administrative practice and procedure, Air pollution control, Hazardous substances, Incorporation by reference, Intergovernmental relations, Reporting and recordkeeping requirements.

Dated: February 26, 2004.

**Michael O. Leavitt,**

*Administrator.*

■ For the reasons stated in the preamble, title 40, chapter I, part 63 of the Code of Federal Regulations is amended as follows:

## PART 63—[AMENDED]

■ 1. The authority citation for part 63 continues to read as follows:

**Authority:** 42 U.S.C. 7401, *et seq.*

## Subpart A—[Amended]

■ 2. Section 63.14 is amended by revising paragraph (b)(27) and paragraph (i)(3) and adding paragraph (b)(35) and paragraphs (b)(39) through (53) to read as follows:

### § 63.14 Incorporations by reference.

* * * * *

(b) * * *

(27) ASTM D6522–00, Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers,[1] IBR approved for § 63.9307(c)(2), Table 4 of Subpart ZZZZ, and Table 5 to Subpart DDDDD of this part.

* * * * *

(35) ASTM D6784–02, Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method),[1] IBR approved for Table 5 to Subpart DDDDD of this part.

* * * * *

(39) ASTM Method D388–99,$^{\epsilon 1}$ Standard Classification of Coals by Rank,[1] IBR approved for § 63.7575.

(40) ASTM D396–02a, Standard Specification for Fuel Oils,[1] IBR approved for § 63.7575.

(41) ASTM D1835–03a, Standard Specification for Liquified Petroleum (LP) Gases,[1] IBR approved for § 63.7575.

(42) ASTM D2013–01, Standard Practice for Preparing Coal Samples for Analysis,[1] IBR approved for Table 6 to Subpart DDDDD of this part.

(43) ASTM D2234–00, $^{\epsilon 1}$ Standard Practice for Collection of a Gross Sample of Coal,[1] IBR approved for Table 6 to Subpart DDDDD of this part.

(44) ASTM D3173–02, Standard Test Method for Moisture in the Analysis Sample of Coal and Coke,[1] IBR approved for Table 6 to Subpart DDDDD of this part.

(45) ASTM D3683–94 (Reapproved 2000), Standard Test Method for Trace Elements in Coal and Coke Ash Absorption,[1] IBR approved for Table 6 to Subpart DDDDD of this part.

(46) ASTM D3684–01, Standard Test Method for Total Mercury in Coal by the Oxygen Bomb Combustion/Atomic Absorption Method,[1] IBR approved for Table 6 to Subpart DDDDD of this part.

(47) ASTM D5198–92 (Reapproved 2003), Standard Practice for Nitric Acid Digestion of Solid Waste,[1] IBR approved for Table 6 to Subpart DDDDD of this part.

(48) ASTM D5865–03a, Standard Test Method for Gross Calorific Value of Coal and Coke,[1] IBR approved for Table 6 to Subpart DDDDD of this part.

(49) ASTM D6323–98 (Reapproved 2003), Standard Guide for Laboratory Subsampling of Media Related to Waste Management Activities,[1] IBR approved for Table 6 to Subpart DDDDD of this part.

(50) ASTM E711–87 (Reapproved 1996), Standard Test Method for Gross Calorific Value of Refuse-Derived Fuel by the Bomb Calorimeter,[1] IBR approved for Table 6 to Subpart DDDDD of this part.

(51) ASTM E776–87 (Reapproved 1996), Standard Test Method for Forms of Chlorine in Refuse-Derived Fuel,[1] IBR approved for Table 6 to Subpart DDDDD of this part.

(52) ASTM E871–82 (Reapproved 1998), Standard Method of Moisture Analysis of Particulate Wood Fuels,[1] IBR approved for Table 6 to Subpart DDDDD of this part.

(53) ASTM E885–88 (Reapproved 1996), Standard Test Methods for Analyses of Metals in Refuse-Derived Fuel by Atomic Absorption Spectroscopy,[1] IBR approved for Table 6 to Subpart DDDDD of this part 63.

* * * * *

(i) * * *

(3) ANSI/ASME PTC 19.10–1981, ''Flue and Exhaust Gas Analyses [Part 10, Instruments and Apparatus],'' IBR approved for §§ 63.865(b), 63.3166(a), 63.3360(e)(1)(iii), 63.3545(a)(3), 63.3555(a)(3), 63.4166(a)(3), 63.4362(a)(3), 63.4766(a)(3), 63.4965(a)(3), 63.5160(d)(1)(iii), 63.9307(c)(2), 63.9323(a)(3), and Table 5 to Subpart DDDDD of this part.

* * * * *

■ 3. Part 63 is amended by adding subpart DDDDD to read as follows:

## Subpart DDDDD—National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters

Sec.

**What This Subpart Covers**

63.7480 What is the purpose of this subpart?
63.7485 Am I subject to this subpart?
63.7490 What is the affected source of this subpart?
63.7491 Are any boilers or process heaters not subject to this subpart?
63.7495 When do I have to comply with this subpart?

**Emission Limits and Work Practice Standards**

63.7499 What are the subcategories of boilers and process heaters?
63.7500 What emission limits, work practice standards, and operating limits must I meet?

**General Compliance Requirements**

63.7505 What are my general requirements for complying with this subpart?
63.7506 Do any boilers or process heaters have limited requirements?
63.7507 What are the health-based compliance alternatives for the hydrogen chloride (HCl) and total selected metals (TSM) standards?

**Testing, Fuel Analyses, and Initial Compliance Requirements**

63.7510 What are my initial compliance requirements and by what date must I conduct them?
63.7515 When must I conduct subsequent performance tests or fuel analyses?
63.7520 What performance tests and procedures must I use?
63.7521 What fuel analyses and procedures must I use?
63.7522 Can I use emission averaging to comply with this subpart?
63.7525 What are my monitoring, installation, operation, and maintenance requirements?
63.7530 How do I demonstrate initial compliance with the emission limits and work practice standards?

**Continuous Compliance Requirements**

63.7535 How do I monitor and collect data to demonstrate continuous compliance?
63.7540 How do I demonstrate continuous compliance with the emission limits and work practice standards?
63.7541 How do I demonstrate continuous compliance under the emission averaging provision?

**Notifications, Reports, and Records**

63.7545 What notifications must I submit and when?
63.7550 What reports must I submit and when?
63.7555 What records must I keep?
63.7560 In what form and how long must I keep my records?

**Other Requirements and Information**

63.7565 What parts of the General Provisions apply to me?
63.7570 Who implements and enforces this subpart?
63.7575 What definitions apply to this subpart?

**Tables to Subpart DDDDD of Part 63**

Table 1 to Subpart DDDDD of Part 63—Emission Limits and Work Practice Standards
Table 2 to Subpart DDDDD of Part 63—Operating Limits for Boilers and Process Heaters With Particulate Matter Emission Limits
Table 3 to Subpart DDDDD of Part 63—Operating Limits for Boilers and Process Heaters With Mercury Emission Limits and Boilers and Process Heaters That Choose to Comply With the Alternative Total Selected Metals Emission Limits
Table 4 to Subpart DDDDD of Part 63—Operating Limits for Boilers and Process Heaters With Hydrogen Chloride Emission Limits
Table 5 to Subpart DDDDD of Part 63—Performance Testing Requirements
Table 6 to Subpart DDDDD of Part 63—Fuel Analysis Requirements
Table 7 to Subpart DDDDD of Part 63—Establishing Operating Limits
Table 8 to Subpart DDDDD of Part 63—Demonstrating Continuous Compliance
Table 9 to Subpart DDDDD of Part 63—Reporting Requirements
Table 10 to Subpart DDDDD of Part 63—Applicability of General Provisions to Subpart DDDDD

**Appendix**

Appendix A to Subpart DDDDD—Methodology and Criteria for Demonstrating Eligibility for the Health-Based Compliance Alternatives Specified for the Large Solid Fuel Subcategory

## Subpart DDDDD—National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters

### What This Subpart Covers

### § 63.7480 What is the purpose of this subpart?

This subpart establishes national emission limits and work practice standards for hazardous air pollutants (HAP) emitted from industrial, commercial, and institutional boilers and process heaters. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limits and work practice standards.

### § 63.7485 Am I subject to this subpart?

You are subject to this subpart if you own or operate an industrial, commercial, or institutional boiler or process heater as defined in § 63.7575 that is located at, or is part of, a major source of HAP as defined in § 63.2 or § 63.761 (40 CFR part 63, subpart HH, National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities), except as specified in § 63.7491.

### § 63.7490 What is the affected source of this subpart?

(a) This subpart applies to new, reconstructed, or existing affected sources as described in paragraphs (a)(1) and (2) of this section.

(1) The affected source of this subpart is the collection of all existing industrial, commercial, and institutional boilers and process heaters within a subcategory located at a major source as defined in § 63.7575.

(2) The affected source of this subpart is each new or reconstructed industrial, commercial, or institutional boiler or

process heater located at a major source as defined in § 63.7575.

(b) A boiler or process heater is new if you commence construction of the boiler or process heater after January 13, 2003, and you meet the applicability criteria at the time you commence construction.

(c) A boiler or process heater is reconstructed if you meet the reconstruction criteria as defined in § 63.2, you commence reconstruction after January 13, 2003, and you meet the applicability criteria at the time you commence reconstruction.

(d) A boiler or process heater is existing if it is not new or reconstructed.

### § 63.7491 Are any boilers or process heaters not subject to this subpart?

The types of boilers and process heaters listed in paragraphs (a) through (o) of this section are not subject to this subpart.

(a) A municipal waste combustor covered by 40 CFR part 60, subpart AAAA, subpart BBBB, subpart Cb or subpart Eb.

(b) A hospital/medical/infectious waste incinerator covered by 40 CFR part 60, subpart Ce or subpart Ec.

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

(d) A boiler or process heater required to have a permit under section 3005 of the Solid Waste Disposal Act or covered by 40 CFR part 63, subpart EEE (*e.g.*, hazardous waste boilers).

(e) A commercial and industrial solid waste incineration unit covered by 40 CFR part 60, subpart CCCC or subpart DDDD.

(f) A recovery boiler or furnace covered by 40 CFR part 63, subpart MM.

(g) A boiler or process heater that is used specifically for research and development. This does not include units that only provide heat or steam to a process at a research and development facility.

(h) A hot water heater as defined in this subpart.

(i) A refining kettle covered by 40 CFR part 63, subpart X.

(j) An ethylene cracking furnace covered by 40 CFR part 63, subpart YY.

(k) Blast furnace stoves as described in the EPA document, entitled ''National Emission Standards for Hazardous Air Pollutants (NESHAP) for Integrated Iron and Steel Plants—Background Information for Proposed Standards,'' (EPA–453/R–01–005).

(l) Any boiler and process heater specifically listed as an affected source in another standard(s) under 40 CFR part 63.

(m) Any boiler and process heater specifically listed as an affected source in another standard(s) established under section 129 of the Clean Air Act (CAA).

(n) Temporary boilers as defined in this subpart.

(o) Blast furnace gas fuel-fired boilers and process heaters as defined in this subpart.

### § 63.7495 When do I have to comply with this subpart?

(a) If you have a new or reconstructed boiler or process heater, you must comply with this subpart by November 12, 2004 or upon startup of your boiler or process heater, whichever is later.

(b) If you have an existing boiler or process heater, you must comply with this subpart no later than September 13, 2007.

(c) If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, paragraphs (c)(1) and (2) of this section apply to you.

(1) Any new or reconstructed boiler or process heater at the existing facility must be in compliance with this subpart upon startup.

(2) Any existing boiler or process heater at the existing facility must be in compliance with this subpart within 3 years after the facility becomes a major source.

(d) You must meet the notification requirements in § 63.7545 according to the schedule in § 63.7545 and in subpart A of this part. Some of the notifications must be submitted before you are required to comply with the emission limits and work practice standards in this subpart.

## Emission Limits and Work Practice Standards

### § 63.7499 What are the subcategories of boilers and process heaters?

The subcategories of boilers and process heaters are large solid fuel, limited use solid fuel, small solid fuel, large liquid fuel, limited use liquid fuel, small liquid fuel, large gaseous fuel, limited use gaseous fuel, and small gaseous fuel. Each subcategory is defined in § 63.7575.

### § 63.7500 What emission limits, work practice standards, and operating limits must I meet?

(a) You must meet the requirements in paragraphs (a)(1) and (2) of this section.

(1) You must meet each emission limit and work practice standard in Table 1 to this subpart that applies to your boiler or process heater, except as provided under § 63.7507.

(2) You must meet each operating limit in Tables 2 through 4 to this subpart that applies to your boiler or process heater. If you use a control device or combination of control devices not covered in Tables 2 through 4 to this subpart, or you wish to establish and monitor an alternative operating limit and alternative monitoring parameters, you must apply to the United States Environmental Protection Agency (EPA) Administrator for approval of alternative monitoring under § 63.8(f).

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

## General Compliance Requirements

### § 63.7505 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limits (including operating limits) and the work practice standards in this subpart at all times, except during periods of startup, shutdown, and malfunction.

(b) You must always operate and maintain your affected source, including air pollution control and monitoring equipment, according to the provisions in § 63.6(e)(1)(i).

(c) You can demonstrate compliance with any applicable emission limit using fuel analysis if the emission rate calculated according to § 63.7530(d) is less than the applicable emission limit. Otherwise, you must demonstrate compliance using performance testing.

(d) If you demonstrate compliance with any applicable emission limit through performance testing, you must develop a site-specific monitoring plan according to the requirements in paragraphs (d)(1) through (4) of this section. This requirement also applies to you if you petition the EPA Administrator for alternative monitoring parameters under § 63.8(f).

(1) For each continuous monitoring system (CMS) required in this section, you must develop and submit to the EPA Administrator for approval a site-specific monitoring plan that addresses paragraphs (d)(1)(i) through (iii) of this section. You must submit this site-specific monitoring plan at least 60 days

before your initial performance evaluation of your CMS.

(i) 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);

(ii) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems; and

(iii) Performance evaluation procedures and acceptance criteria (*e.g.*, calibrations).

(2) In your site-specific monitoring plan, you must also address paragraphs (d)(2)(i) through (iii) of this section.

(i) Ongoing operation and maintenance procedures in accordance with the general requirements of § 63.8(c)(1), (c)(3), and (c)(4)(ii);

(ii) Ongoing data quality assurance procedures in accordance with the general requirements of § 63.8(d); and

(iii) Ongoing recordkeeping and reporting procedures in accordance with the general requirements of § 63.10(c), (e)(1), and (e)(2)(i).

(3) You must conduct a performance evaluation of each CMS in accordance with your site-specific monitoring plan.

(4) You must operate and maintain the CMS in continuous operation according to the site-specific monitoring plan.

(e) If you have an applicable emission limit or work practice standard, you must develop and implement a written startup, shutdown, and malfunction plan (SSMP) according to the provisions in § 63.6(e)(3).

### § 63.7506 Do any boilers or process heaters have limited requirements?

(a) New or reconstructed boilers and process heaters in the large liquid fuel subcategory or the limited use liquid fuel subcategory that burn only fossil fuels and other gases and do not burn any residual oil are subject to the emission limits and applicable work practice standards in Table 1 to this subpart. You are not required to conduct a performance test to demonstrate compliance with the emission limits. You are not required to set and maintain operating limits to demonstrate continuous compliance with the emission limits. However, you must meet the requirements in paragraphs (a)(1) and (2) of this section and meet the CO work practice standard in Table 1 to this subpart.

(1) To demonstrate initial compliance, you must include a signed statement in the Notification of Compliance Status report required in § 63.7545(e) that indicates you burn only liquid fossil fuels other than residual oils, either alone or in combination with gaseous fuels.

(2) To demonstrate continuous compliance with the applicable emission limits, you must also keep records that demonstrate that you burn only liquid fossil fuels other than residual oils, either alone or in combination with gaseous fuels. You must also include a signed statement in each semiannual compliance report required in § 63.7550 that indicates you burned only liquid fossil fuels other than residual oils, either alone or in combination with gaseous fuels, during the reporting period.

(b) The affected boilers and process heaters listed in paragraphs (b)(1) through (3) of this section are subject to only the initial notification requirements in § 63.9(b) (*i.e.*, they are not subject to the emission limits, work practice standards, performance testing, monitoring, SSMP, site-specific monitoring plans, recordkeeping and reporting requirements of this subpart or any other requirements in subpart A of this part).

(1) Existing large and limited use gaseous fuel units.

(2) Existing large and limited use liquid fuel units.

(3) New or reconstructed small liquid fuel units that burn only gaseous fuels or distillate oil. New or reconstructed small liquid fuel boilers and process heaters that commence burning of any other type of liquid fuel must comply with all applicable requirements of this subpart and subpart A of this part upon startup of burning the other type of liquid fuel.

(c) The affected boilers and process heaters listed in paragraphs (c)(1) through (4) of this section are not subject to the initial notification requirements in § 63.9(b) and are not subject to any requirements in this subpart or in subpart A of this part (*i.e.*, they are not subject to the emission limits, work practice standards, performance testing, monitoring, SSM plans, site-specific monitoring plans, recordkeeping and reporting requirements of this subpart, or any other requirements in subpart A of this part.

(1) Existing small solid fuel boilers and process heaters.

(2) Existing small liquid fuel boilers and process heaters.

(3) Existing small gaseous fuel boilers and process heaters.

(4) New or reconstructed small gaseous fuel units.

### § 63.7507 What are the health-based compliance alternatives for the hydrogen chloride (HCl) and total selected metals (TSM) standards?

(a) As an alternative to the requirement for large solid fuel boilers located at a single facility to demonstrate compliance with the HCl emission limit in Table 1 to this subpart, you may demonstrate eligibility for the health-based compliance alternative for HCl emissions under the procedures prescribed in appendix A to this subpart.

(b) In lieu of complying with the TSM emission standards in Table 1 to this subpart based on the sum of emissions for the eight selected metals, you may demonstrate eligibility for complying with the TSM emission standards in Table 1 based on the sum of emissions for seven selected metals (by excluding manganese emissions from the summation of TSM emissions) under the procedures prescribed in appendix A to this subpart.

## Testing, Fuel Analyses, and Initial Compliance Requirements

### § 63.7510 What are my initial compliance requirements and by what date must I conduct them?

(a) For affected sources that elect to demonstrate compliance with any of the emission limits of this subpart through performance testing, your initial compliance requirements include conducting performance tests according to § 63.7520 and Table 5 to this subpart, conducting a fuel analysis for each type of fuel burned in your boiler or process heater according to § 63.7521 and Table 6 to this subpart, establishing operating limits according to § 63.7530 and Table 7 to this subpart, and conducting CMS performance evaluations according to § 63.7525.

(b) For affected sources that elect to demonstrate compliance with the emission limits for HCl, mercury, or TSM through fuel analysis, your initial compliance requirement is to conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to § 63.7521 and Table 6 to this subpart and establish operating limits according to § 63.7530 and Table 8 to this subpart.

(c) For affected sources that have an applicable work practice standard, your initial compliance requirements depend on the subcategory and rated capacity of your boiler or process heater. If your boiler or process heater is in any of the limited use subcategories or has a heat input capacity less than 100 MMBtu per hour, your initial compliance demonstration is conducting a performance test for carbon monoxide according to Table 5 to this subpart. If your boiler or process heater is in any of the large subcategories and has a heat input capacity of 100 MMBtu per hour or greater, your initial compliance demonstration is conducting a performance evaluation of your continuous emission monitoring system for carbon monoxide according to § 63.7525(a).

(d) For existing affected sources, you must demonstrate initial compliance no later than 180 days after the compliance date that is specified for your source in § 63.7495 and according to the applicable provisions in § 63.7(a)(2) as cited in Table 10 to this subpart.

(e) If your new or reconstructed affected source commenced construction or reconstruction between January 13, 2003 and November 12, 2004, you must demonstrate initial compliance with either the proposed emission limits and work practice standards or the promulgated emission limits and work practice standards no later than 180 days after November 12, 2004 or within 180 days after startup of the source, whichever is later, according to § 63.7(a)(2)(ix).

(f) If your new or reconstructed affected source commenced construction or reconstruction between January 13, 2003, and November 12, 2004, and you chose to comply with the proposed emission limits and work practice standards when demonstrating initial compliance, you must conduct a second compliance demonstration for the promulgated emission limits and work practice standards within 3 years after November 12, 2004 or within 3 years after startup of the affected source, whichever is later.

(g) If your new or reconstructed affected source commences construction or reconstruction after November 12, 2004, you must demonstrate initial compliance with the promulgated emission limits and work practice standards no later than 180 days after startup of the source.

### § 63.7515 When must I conduct subsequent performance tests or fuel analyses?

(a) You must conduct all applicable performance tests according to § 63.7520 on an annual basis, unless you follow the requirements listed in paragraphs (b) through (d) of this section. Annual performance tests must be completed between 10 and 12 months after the previous performance test, unless you follow the requirements listed in paragraphs (b) through (d) of this section.

(b) You can conduct performance tests less often for a given pollutant if your performance tests for the pollutant (particulate matter, HCl, mercury, or TSM) for at least 3 consecutive years show that you comply with the emission limit. In this case, you do not have to conduct a performance test for that pollutant for the next 2 years. You must conduct a performance test during the third year and no more than 36 months after the previous performance test.

(c) If your boiler or process heater continues to meet the emission limit for particulate matter, HCl, mercury, or TSM, you may choose to conduct performance tests for these pollutants every third year, but each such performance test must be conducted no more than 36 months after the previous performance test.

(d) If a performance test shows noncompliance with an emission limit for particulate matter, HCl, mercury, or TSM, you must conduct annual performance tests for that pollutant until all performance tests over a consecutive 3-year period show compliance.

(e) If you have an applicable work practice standard for carbon monoxide and your boiler or process heater is in any of the limited use subcategories or has a heat input capacity less than 100 MMBtu per hour, you must conduct annual performance tests for carbon monoxide according to § 63.7520. Each annual performance test must be conducted between 10 and 12 months after the previous performance test.

(f) You must conduct a fuel analysis according to § 63.7521 for each type of fuel burned no later than 5 years after the previous fuel analysis for each fuel type. If you burn a new type of fuel, you must conduct a fuel analysis before burning the new type of fuel in your boiler or process heater. You must still meet all applicable continuous compliance requirements in § 63.7540.

(g) You must report the results of performance tests and fuel analyses within 60 days after the completion of the performance tests or fuel analyses. This report should also verify that the operating limits for your affected source have not changed or provide documentation of revised operating parameters established according to § 63.7530 and Table 7 to this subpart, as applicable. The reports for all subsequent performance tests and fuel analyses should include all applicable information required in § 63.7550.

### § 63.7520 What performance tests and procedures must I use?

(a) You must conduct all performance tests according to § 63.7(c), (d), (f), and (h). You must also develop a site-specific test plan according to the requirements in § 63.7(c) if you elect to demonstrate compliance through performance testing.

(b) You must conduct each performance test according to the requirements in Table 5 to this subpart.

(c) New or reconstructed boilers or process heaters in one of the liquid fuel subcategories that burn only fossil fuels and other gases and do not burn any residual oil must demonstrate compliance according to § 63.7506(a).

(d) You must conduct each performance test under the specific conditions listed in Tables 5 and 7 to this subpart. You must conduct performance tests at the maximum normal operating load while burning the type of fuel or mixture of fuels that have the highest content of chlorine, mercury, and total selected metals, and you must demonstrate initial compliance and establish your operating limits based on these tests. These requirements could result in the need to conduct more than one performance test.

(e) You may not conduct performance tests during periods of startup, shutdown, or malfunction.

(f) You must conduct three separate test runs for each performance test required in this section, as specified in § 63.7(e)(3). Each test run must last at least 1 hour.

(g) To determine compliance with the emission limits, you must use the F-Factor methodology and equations in sections 12.2 and 12.3 of EPA Method 19 of appendix A to part 60 of this chapter to convert the measured particulate matter concentrations, the measured HCl concentrations, the measured TSM concentrations, and the measured mercury concentrations that result from the initial performance test to pounds per million Btu heat input emission rates using F-factors.

### § 63.7521 What fuel analyses and procedures must I use?

(a) You must conduct fuel analyses according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable.

(b) You must develop and submit a site-specific fuel analysis plan to the EPA Administrator for review and approval according to the following procedures and requirements in paragraphs (b)(1) and (2) of this section.

(1) You must submit the fuel analysis plan no later than 60 days before the date that you intend to demonstrate compliance.

(2) You must include the information contained in paragraphs (b)(2)(i)

through (vi) of this section in your fuel analysis plan.

(i) The identification of all fuel types anticipated to be burned in each boiler or process heater.

(ii) For each fuel type, the notification of whether you or a fuel supplier will be conducting the fuel analysis.

(iii) For each fuel type, a detailed description of the sample location and specific procedures to be used for collecting and preparing the composite samples if your procedures are different from paragraph (c) or (d) of this section. 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 fuel type, the analytical methods, with the expected minimum detection levels, to be used for the measurement of selected total metals, chlorine, or mercury.

(v) If you request to use an alternative analytical method other than those required by Table 6 to this subpart, you must also include a detailed description of the methods and procedures that will be used.

(vi) If you 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 this subpart.

(c) At a minimum, you must obtain three composite fuel samples for each fuel type according to the procedures in paragraph (c)(1) or (2) of this section.

(1) If sampling from a belt (or screw) feeder, collect fuel samples according to paragraphs (c)(1)(i) and (ii) of this section.

(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. Collect all the material (fines and coarse) in the full cross-section. Transfer the sample to a clean plastic bag.

(ii) Each composite sample will consist of a minimum of three samples collected at approximately equal intervals during the testing period.

(2) If sampling from a fuel pile or truck, collect fuel samples according to paragraphs (c)(2)(i) through (iii) of this section.

(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 depth of 18 inches. Insert a clean flat square shovel into the hole and withdraw a sample, making sure that large pieces do not fall off during sampling.

(iii) Transfer all samples to a clean plastic bag for further processing.

(d) Prepare each composite sample according to the procedures in paragraphs (d)(1) through (7) of this section.

(1) Throughly mix and pour the entire composite sample over a clean plastic sheet.

(2) Break sample pieces larger than 3 inches into smaller sizes.

(3) Make a pie shape with the entire composite sample and subdivide it into four equal parts.

(4) Separate one of the quarter samples as the first subset.

(5) If this subset is too large for grinding, repeat the procedure in paragraph (d)(3) of this section with the quarter sample and obtain a one-quarter subset from this sample.

(6) Grind the sample in a mill.

(7) Use the procedure in paragraph (d)(3) of this section to obtain a one-quarter subsample for analysis. If the quarter sample is too large, subdivide it further using the same procedure.

(e) Determine the concentration of pollutants in the fuel (mercury, chlorine, and/or total selected metals) in units of pounds per million Btu of each composite sample for each fuel type according to the procedures in Table 6 to this subpart.

### § 63.7522 Can I use emission averaging to comply with this subpart?

(a) As an alternative to meeting the requirements of § 63.7500, if you have more than one existing large solid fuel boiler located at your facility, you may demonstrate compliance by emission averaging according to the procedures in this section in a State that does not choose to exclude emission averaging.

(b) For each existing large solid fuel boiler 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 November 12, 2004 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 November 12, 2004.

(c) You may average particulate matter or TSM, HCl, and mercury emissions from existing large solid fuel boilers to demonstrate compliance with the limits in Table 1 to this subpart if you satisfy the requirements in paragraphs (d), (e), and (f) of this section.

(d) The weighted average emissions from the existing large solid fuel boilers participating in the emissions averaging option must be in compliance with the limits in Table 1 to this subpart at all times following the compliance date specified in § 63.7495.

(e) You must demonstrate initial compliance according to paragraphs (e)(1) or (2) of this section.

(1) You must use Equation 1 of this section to demonstrate that the particulate matter or TSM, HCl, and mercury emissions from all existing large solid fuel boilers participating in the emissions averaging option do not exceed the emission limits in Table 1 to this subpart.

$$\text{AveWeighted Emissions} = \sum_{i=1}^{n}(\text{Er} \times \text{Hm}) \div \sum_{i=1}^{n}\text{Hm} \qquad \text{(Eq. 1)}$$

Where:

AveWeighted = Average weighted emissions for particulate matter or TSM, HCl, or mercury, in units of pounds per million Btu of heat input.

Er = Emission rate (as calculated according to Table 5 to this subpart) or fuel analysis (as calculated by the applicable equation in § 63.7530(d)) for boiler, i, for particulate matter or TSM, HCl, or mercury, in units of pounds per million Btu of heat input.

Hm = Maximum rated heat input capacity of boiler, i, in units of million Btu per hour.

n = Number of large solid fuel boilers participating in the emissions averaging option.

(2) If you are not capable of monitoring heat input, you can use Equation 2 of this section as an alternative to using equation 1 of this section to demonstrate that the particulate matter or TSM, HCl, and mercury emissions from all existing large solid fuel boilers participating in the emissions averaging option do not exceed the emission limits in Table 1 to this subpart.

$$\text{AveWeighted Emissions} = \sum_{i=1}^{n}(\text{Er} \times \text{Sm} \times \text{Cf}) \div \sum_{i=1}^{n}\text{Sm} \times \text{Cf} \qquad \text{(Eq. 2)}$$

Where:

AveWeighted = Average weighted emission level for PM or TSM, HCl, or mercury, in units of pounds per million Btu of heat input.

Er = Emission rate (as calculated according to Table 5 to this subpart) or fuel analysis (as calculated by the applicable equation in § 63.7530(d)) for boiler, i, for particulate matter or TSM, HCl, or mercury, in units of pounds per million Btu of heat input.

Sm = Maximum steam generation by boiler, i, in units of pounds.

Cf = Conversion factor, calculated from the most recent compliance test, in units of million Btu of heat input per pounds of steam generated.

(f) You must demonstrate continuous compliance on a 12-month rolling average basis determined at the end of every month (12 times per year) according to paragraphs (f)(1) and (2). The first 12-month rolling-average period begins on the compliance date specified in § 63.7495.

(1) For each calendar month, you must use Equation 3 of this section to calculate the 12-month rolling average weighted emission limit using the actual heat capacity for each existing large solid fuel boiler participating in the emissions averaging option.

$$\text{AveWeighted Emissions} = \sum_{i=1}^{n}(\text{Er} \times \text{Hb}) \div \sum_{i=1}^{n}\text{Hb} \qquad \text{(Eq. 3)}$$

Where:

AveWeighted Emissions = 12-month rolling average weighted emission level for particulate matter or TSM, HCl, or mercury, in units of pounds per million Btu of heat input.

Er = Emission rate, calculated during the most recent compliance test, (as calculated according to Table 5 to this subpart) or fuel analysis (as calculated by the applicable equation in § 63.7530(d)) for boiler, i, for particulate matter or TSM, HCl, or mercury, in units of pounds per million Btu of heat input.

Hb = The average heat input for each calendar month of boiler, i, in units of million Btu.

n = Number of large solid fuel boilers participating in the emissions averaging option.

(2) If you are not capable of monitoring heat input, you can use Equation 4 of this section as an alternative to using Equation 3 of this section to calculate the 12-month rolling average weighted emission limit using the actual steam generation from the large solid fuel boilers participating in the emissions averaging option.

$$\text{AveWeighted Emissions} = \sum_{i=1}^{n}(\text{Er} \times \text{Sa} \times \text{Cf}) \div \sum_{i=1}^{n}\text{Sa} \times \text{Cf} \qquad \text{(Eq. 4)}$$

Where:

AveWeighted Emissions = 12-month rolling average weighted emission level for PM or TSM, HCl, or mercury, in units of pounds per million Btu of heat input.

Er = Emission rate, calculated during the most recent compliance test (as calculated according to Table 5 to this subpart) or fuel analysis (as calculated by the applicable equation in § 63.7530(d)) for boiler, i, for particulate matter or TSM, HCl, or mercury, in units of pounds per million Btu of heat input.

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

Cf = Conversion factor, as calculated during the most recent compliance test, in units of million Btu of heat input per pounds of steam generated.

(g) You must develop and submit an implementation plan for emission averaging to the applicable regulatory authority for review and approval according to the following procedures and requirements in paragraphs (g)(1) through (4).

(1) You 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.

(2) You must include the information contained in paragraphs (g)(2)(i) through (vii) of this section in your implementation plan for all emission sources included in an emissions average:

(i) The identification of all existing large solid fuel boilers in the averaging group, including for each either the applicable HAP emission level or the control technology installed on;

(ii) The process parameter (heat input or steam generated) that will be monitored for each averaging group of large solid fuel boilers;

(iii) The specific control technology or pollution prevention measure to be used for each emission source in the averaging group and the date of its installation or application. If the pollution prevention measure reduces or eliminates emissions from multiple sources, the owner or operator must identify each source;

(iv) The test plan for the measurement of particulate matter (or TSM), HCl, or mercury emissions in accordance with the requirements in § 63.7520;

(v) The operating parameters to be monitored for each control system or device and a description of how the operating limits will be determined;

(vi) If you request to monitor an alternative operating parameter pursuant to § 63.7525, you must also include:

(A) A description of the parameter(s) to be monitored and an explanation of the criteria used to select the parameter(s); and

(B) 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 applicable regulatory authority, that the proposed monitoring frequency is sufficient to represent control device operating conditions; and

(vii) A demonstration that compliance with each of the applicable emission limit(s) will be achieved under representative operating conditions.

(3) Upon receipt, the regulatory authority 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 this section; and

(ii) Whether the plan presents sufficient information to determine that compliance will be achieved and maintained.

(4) The applicable regulatory authority 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; or

(ii) The inclusion of any emission source other than an existing large solid fuel boiler.

### § 63.7525 What are my monitoring, installation, operation, and maintenance requirements?

(a) If you have an applicable work practice standard for carbon monoxide, and your boiler or process heater is in any of the large subcategories and has a heat input capacity of 100 MMBtu per hour or greater, you must install, operate, and maintain a continuous emission monitoring system (CEMS) for carbon monoxide according to the procedures in paragraphs (a)(1) through (6) of this section by the compliance date specified in § 63.7495.

(1) Each CEMS must be installed, operated, and maintained according to Performance Specification (PS) 4A of 40 CFR part 60, appendix B, and according to the site-specific monitoring plan developed according to § 63.7505(d).

(2) You must conduct a performance evaluation of each CEMS according to the requirements in § 63.8 and according to PS 4A of 40 CFR part 60, appendix B.

(3) Each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(4) The CEMS data must be reduced as specified in § 63.8(g)(2).

(5) You must calculate and record a 30-day rolling average emission rate on a daily basis. A new 30-day rolling average emission rate is calculated as the average of all of the hourly CO emission data for the preceding 30 operating days.

(6) For purposes of calculating data averages, you must not use data recorded during periods of monitoring malfunctions, associated repairs, out-of-control periods, required quality assurance or control activities, or when your boiler or process heater is operating at less than 50 percent of its rated capacity. You must use all the data collected during all other periods in assessing compliance. Any period for which the monitoring system is out of control and data are not available for required calculations constitutes a deviation from the monitoring requirements.

(b) If you have an applicable opacity operating limit, you must install, operate, certify and maintain each continuous opacity monitoring system (COMS) according to the procedures in paragraphs (b)(1) through (7) of this section by the compliance date specified in § 63.7495.

(1) Each COMS must be installed, operated, and maintained according to PS 1 of 40 CFR part 60, appendix B.

(2) You must conduct a performance evaluation of each COMS according to the requirements in § 63.8 and according to PS 1 of 40 CFR part 60, appendix B.

(3) As specified in § 63.8(c)(4)(i), each COMS must 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.

(4) The COMS data must be reduced as specified in § 63.8(g)(2).

(5) You must include in your site-specific monitoring plan procedures and acceptance criteria for operating and maintaining each COMS according to the requirements in § 63.8(d). At a minimum, the monitoring plan must include a daily calibration drift assessment, a quarterly performance audit, and an annual zero alignment audit of each COMS.

(6) You must operate and maintain each COMS according to the requirements in the monitoring plan and the requirements of § 63.8(e). Identify periods the COMS is out of control including any periods that the COMS fails to pass a daily calibration drift assessment, a quarterly performance audit, or an annual zero alignment audit.

(7) You must determine and record all the 6-minute averages (and 1-hour block averages as applicable) collected for periods during which the COMS is not out of control.

(c) If you have an operating limit that requires the use of a CMS, you must install, operate, and maintain each continuous parameter monitoring system (CPMS) according to the procedures in paragraphs (c)(1) through (5) of this section by the compliance date specified in § 63.7495.

(1) The CPMS must complete a minimum of one cycle of operation for each successive 15-minute period. You must have a minimum of four successive cycles of operation to have a valid hour of data.

(2) Except for monitoring malfunctions, associated repairs, and required quality assurance or control

activities (including, as applicable, calibration checks and required zero and span adjustments), you must conduct all monitoring in continuous operation at all times that the unit is operating. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

(3) For purposes of calculating data averages, you must not use data recorded during monitoring malfunctions, associated repairs, out of control periods, or required quality assurance or control activities. You must use all the data collected during all other periods in assessing compliance. Any period for which the monitoring system is out-of-control and data are not available for required calculations constitutes a deviation from the monitoring requirements.

(4) Determine the 3-hour block average of all recorded readings, except as provided in paragraph (c)(3) of this section.

(5) Record the results of each inspection, calibration, and validation check.

(d) If you have an operating limit that requires the use of a flow measurement device, you must meet the requirements in paragraphs (c) and (d)(1) through (4) of this section.

(1) Locate the flow sensor and other necessary equipment in a position that provides a representative flow.

(2) Use a flow sensor with a measurement sensitivity of 2 percent of the flow rate.

(3) Reduce swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.

(4) Conduct a flow sensor calibration check at least semiannually.

(e) If you have an operating limit that requires the use of a pressure measurement device, you must meet the requirements in paragraphs (c) and (e)(1) through (6) of this section.

(1) Locate the pressure sensor(s) in a position that provides a representative measurement of the pressure.

(2) Minimize or eliminate pulsating pressure, vibration, and internal and external corrosion.

(3) Use a gauge with a minimum tolerance of 1.27 centimeters of water or a transducer with a minimum tolerance of 1 percent of the pressure range.

(4) Check pressure tap pluggage daily.

(5) Using a manometer, check gauge calibration quarterly and transducer calibration monthly.

(6) Conduct calibration checks any time the sensor exceeds the manufacturer's specified maximum operating pressure range or install a new pressure sensor.

(f) If you have an operating limit that requires the use of a pH measurement device, you must meet the requirements in paragraphs (c) and (f)(1) through (3) of this section.

(1) Locate the pH sensor in a position that provides a representative measurement of scrubber effluent pH.

(2) Ensure the sample is properly mixed and representative of the fluid to be measured.

(3) Check the pH meter's calibration on at least two points every 8 hours of process operation.

(g) If you have an operating limit that requires the use of equipment to monitor voltage and secondary current (or total power input) of an electrostatic precipitator (ESP), you must use voltage and secondary current monitoring equipment to measure voltage and secondary current to the ESP.

(h) If you have an operating limit that requires the use of equipment to monitor sorbent injection rate (*e.g.*, weigh belt, weigh hopper, or hopper flow measurement device), you must meet the requirements in paragraphs (c) and (h)(1) through (3) of this section.

(1) Locate the device in a position(s) that provides a representative measurement of the total sorbent injection rate.

(2) Install and calibrate the device in accordance with manufacturer's procedures and specifications.

(3) At least annually, calibrate the device in accordance with the manufacturer's procedures and specifications.

(i) If you elect to use a fabric filter bag leak detection system to comply with the requirements of this subpart, you must install, calibrate, maintain, and continuously operate a bag leak detection system as specified in paragraphs (i)(1) through (8) of this section.

(1) You must install and operate a bag leak detection system for each exhaust stack of the fabric filter.

(2) Each bag leak detection system must be installed, operated, calibrated, and maintained in a manner consistent with the manufacturer's written specifications and recommendations and in accordance with the guidance provided in EPA–454/R–98–015, September 1997.

(3) The bag leak detection system must be certified by the manufacturer to be capable of detecting particulate matter emissions at concentrations of 10 milligrams per actual cubic meter or less.

(4) The bag leak detection system sensor must provide output of relative or absolute particulate matter loadings.

(5) The bag leak detection system must be equipped with a device to continuously record the output signal from the sensor.

(6) The bag leak detection system must be equipped with an alarm system that will sound automatically when an increase in relative particulate matter emissions over a preset level is detected. The alarm must be located where it is easily heard by plant operating personnel.

(7) For positive pressure fabric filter systems that do not duct all compartments of cells to a common stack, a bag leak detection system must be installed in each baghouse compartment or cell.

(8) Where multiple bag leak detectors are required, the system's instrumentation and alarm may be shared among detectors.

### § 63.7530 How do I demonstrate initial compliance with the emission limits and work practice standards?

(a) You must demonstrate initial compliance with each emission limit and work practice standard that applies to you by either conducting initial performance tests and establishing operating limits, as applicable, according to § 63.7520, paragraph (c) of this section, and Tables 5 and 7 to this subpart OR conducting initial fuel analyses to determine emission rates and establishing operating limits, as applicable, according to § 63.7521, paragraph (d) of this section, and Tables 6 and 8 to this subpart.

(b) New or reconstructed boilers or process heaters in one of the liquid fuel subcategories that burn only fossil fuels and other gases and do not burn any residual oil must demonstrate compliance according to § 63.7506(a).

(c) If you demonstrate compliance through performance testing, you must establish each site-specific operating limit in Tables 2 through 4 to this subpart that applies to you according to the requirements in § 63.7520, Table 7 to this subpart, and paragraph (c)(4) of this section, as applicable. You must also conduct fuel analyses according to § 63.7521 and establish maximum fuel pollutant input levels according to paragraphs (c)(1) through (3) of this section, as applicable.

(1) You must establish the maximum chlorine fuel input ($C_{input}$) during the initial performance testing according to the procedures in paragraphs (c)(1)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of chlorine.

(ii) During the performance testing for HCl, you must determine 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 ($C_i$).

(iii) You must establish a maximum chlorine input level using Equation 5 of this section.

$$Cl_{input} = \sum_{i=1}^{n} \left[ (C_i)(Q_i) \right] \qquad \text{(Eq. 5)}$$

Where:

$Cl_{input}$ = Maximum amount of chlorine entering the boiler or process heater through fuels burned in units of pounds per million Btu.

$C_i$ = Arithmetic average concentration of chlorine in fuel type, i, analyzed according to § 63.7521, in units of pounds per million Btu.

$Q_i$ = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of chlorine. If you do not burn multiple fuel types during the performance testing, it is not necessary to determine the value of this term. Insert a value of ''1'' for $Q_i$.

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

(2) If you choose to comply with the alternative TSM emission limit instead of the particulate matter emission limit, you must establish the maximum TSM fuel input level ($TSM_{input}$) during the initial performance testing according to the procedures in paragraphs (c)(2)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of TSM.

(ii) During the performance testing for TSM, you must determine the fraction of total heat input from each fuel burned ($Q_i$) based on the fuel mixture that has the highest content of total selected metals, and the average TSM concentration of each fuel type burned ($M_i$).

(iii) You must establish a baseline TSM input level using Equation 6 of this section.

$$TSM_{input} = \sum_{i=1}^{n} \left[ (M_i)(Q_i) \right] \qquad \text{(Eq. 6)}$$

Where:

$TSM_{input}$ = Maximum amount of TSM entering the boiler or process heater through fuels burned in units of pounds per million Btu.

$M_i$ = Arithmetic average concentration of TSM in fuel type, i, analyzed according to § 63.7521, in units of pounds per million Btu.

$Q_i$ = Fraction of total heat input from based fuel type, i, based on the fuel mixture that has the highest content of TSM. If you do not burn multiple fuel types during the performance test, it is not necessary to determine the value of this term. Insert a value of ''1'' for $Q_i$.

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

(3) You must establish the maximum mercury fuel input level ($Mercury_{input}$) during the initial performance testing using the procedures in paragraphs (c)(3)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of mercury.

(ii) During the compliance demonstration for mercury, you must determine the fraction of total heat input for each fuel burned ($Q_i$) based on the fuel mixture that has the highest content of mercury, and the average mercury concentration of each fuel type burned ($HG_i$).

(iii) You must establish a maximum mercury input level using Equation 7 of this section.

$$Mercury_{input} = \sum_{i=1}^{n} \left[ (HG_i)(Q_i) \right] \qquad \text{(Eq. 7)}$$

Where:

$Mercury_{input}$ = Maximum amount of mercury entering the boiler or process heater through fuels burned in units of pounds per million Btu.

$HG_i$ = Arithmetic average concentration of mercury in fuel type, i, analyzed according to § 63.7521, in units of pounds per million Btu.

$Q_i$ = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest mercury content. If you do not burn multiple fuel types during the performance test, it is not necessary to determine the value of this term. Insert a value of ''1'' for $Q_i$.

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

(4) You must establish parameter operating limits according to paragraphs (c)(4)(i) through (iv) of this section.

(i) For a wet scrubber, you must establish the minimum scrubber effluent pH, liquid flowrate, and pressure drop as defined in § 63.7575, as your operating limits during the three-run performance test. If you use a wet scrubber and you conduct separate performance tests for particulate matter, HCl, and mercury emissions, you must establish one set of minimum scrubber effluent pH, liquid flowrate, and pressure drop operating limits. The minimum scrubber effluent pH operating limit must be established during the HCl performance test. If you conduct multiple performance tests, you must set the minimum liquid flowrate and pressure drop operating limits at the highest minimum values established during the performance tests.

(ii) For an electrostatic precipitator, you must establish the minimum voltage and secondary current (or total power input), as defined in § 63.7575, as your operating limits during the three-run performance test.

(iii) For a dry scrubber, you must establish the minimum sorbent injection rate, as defined in § 63.7575, as your operating limit during the three-run performance test.

(iv) The operating limit for boilers or process heaters with fabric filters that choose to demonstrate continuous compliance through bag leak detection systems 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 alarm does not sound more than 5 percent of the operating time during a 6-month period.

(d) If you elect to demonstrate compliance with an applicable emission limit through fuel analysis, you must conduct fuel analyses according to § 63.7521 and follow the procedures in paragraphs (d)(1) through (5) of this section.

(1) If you burn more than one fuel type, you must determine the fuel mixture you could burn in your boiler or process heater that would result in the maximum emission rates of the pollutants that you elect to demonstrate compliance through fuel analysis.

(2) You must determine the 90th percentile confidence level fuel pollutant concentration of the composite samples analyzed for each fuel type using the one-sided z-statistic test described in Equation 8 of this section.

$$P_{90} = \text{mean} + (SD \times t) \qquad \text{(Eq. 8)}$$

Where:

$P_{90}$ = 90th percentile confidence level pollutant concentration, in pounds per million Btu.

mean = Arithmetic average of the fuel pollutant concentration in the fuel samples analyzed according to § 63.7521, in units of pounds per million Btu.

SD = Standard deviation of the pollutant concentration in the fuel samples analyzed according to § 63.7521, in units of pounds per million Btu.

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

(3) To demonstrate compliance with the applicable emission limit for HCl, the HCl emission rate that you calculate for your boiler or process heater using Equation 9 of this section must be less than the applicable emission limit for HCl.

$$\mathrm{HCl} = \sum_{i=1}^{n}\left[(C_{i90})(Q_i)(1.028)\right] \qquad \text{(Eq. 9)}$$

Where:

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

$C_{i90}$ = 90th percentile confidence level concentration of chlorine in fuel type, i, in units of pounds per million Btu as calculated according to Equation 8 of this section.

$Q_i$ = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of chlorine. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of ''1'' for $Q_i$.

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

1.028 = Molecular weight ratio of HCl to chlorine.

(4) To demonstrate compliance with the applicable emission limit for TSM, the TSM emission rate that you calculate for your boiler or process heater using Equation 10 of this section must be less than the applicable emission limit for TSM.

$$\mathrm{TSM} = \sum_{i=1}^{n}\left[(M_{i90})(Q_i)\right] \qquad \text{(Eq. 10)}$$

Where:

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

$M_{i90}$ = 90th percentile confidence level concentration of TSM in fuel, i, in units of pounds per million Btu as calculated according to Equation 8 of this section.

$Q_i$ = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of total selected metals. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of ''1'' for $Q_i$.

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

(5) To demonstrate compliance with the applicable emission limit for mercury, the mercury emission rate that you calculate for your boiler or process heater using Equation 11 of this section must be less than the applicable emission limit for mercury.

$$\mathrm{Mercury} = \sum_{i=1}^{n}\left[(HG_{i90})(Q_i)\right] \qquad \text{(Eq. 11)}$$

Where:

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

$HG_{i90}$ = 90th percentile confidence level concentration of mercury in fuel, i, in units of pounds per million Btu as calculated according to Equation 8 of this section.

$Q_i$ = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest mercury content. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of ''1'' for $Q_i$.

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

(e) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in § 63.7545(e).

## Continuous Compliance Requirements

### § 63.7535 How do I monitor and collect data to demonstrate continuous compliance?

(a) You must monitor and collect data according to this section and the site-specific monitoring plan required by § 63.7505(d).

(b) Except for monitor malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), you must monitor continuously (or collect data at all required intervals) at all times that the affected source is operating.

(c) You may not use data recorded during monitoring malfunctions, associated repairs, or required quality assurance or control activities in data averages and calculations used to report emission or operating levels. You must use all the data collected during all other periods in assessing the operation of the control device and associated control system. Boilers and process heaters that have an applicable carbon monoxide work practice standard and are required to install and operate a CEMS, may not use data recorded during periods when the boiler or process heater is operating at less than 50 percent of its rated capacity.

### § 63.7540 How do I demonstrate continuous compliance with the emission limits and work practice standards?

(a) You must demonstrate continuous compliance with each emission limit, operating limit, and work practice standard in Tables 1 through 4 to this subpart that applies to you according to the methods specified in Table 8 to this subpart and paragraphs (a)(1) through (10) of this section.

(1) Following the date on which the initial performance test is completed or is required to be completed under §§ 63.7 and 63.7510, whichever date comes first, you must not operate above any of the applicable maximum operating limits or below any of the applicable minimum operating limits listed in Tables 2 through 4 to this subpart at all times except during periods of startup, shutdown and malfunction. Operating limits do not apply during performance tests. Operation above the established maximum or below the established minimum operating limits shall constitute a deviation of established operating limits.

(2) You must keep records 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 either result in lower emissions of TSM, HCl, and mercury, than the applicable emission limit for each pollutant (if you demonstrate compliance through fuel analysis), or result in lower fuel input of TSM, chlorine, and mercury than the maximum values calculated during the last performance tests (if you demonstrate compliance through performance testing).

(3) If you demonstrate compliance with an applicable HCl emission limit through fuel analysis and you plan to burn a new type of fuel, you must recalculate the HCl emission rate using Equation 9 of § 63.7530 according to paragraphs (a)(3)(i) through (iii) of this section.

(i) You must determine the chlorine concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to § 63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of chlorine.

(iii) Recalculate the HCl emission rate from your boiler or process heater under these new conditions using Equation 9 of § 63.7530. The recalculated HCl emission rate must be less than the applicable emission limit.

(4) If you demonstrate compliance with an applicable HCl emission limit through performance testing and you plan to burn a new type of fuel type or a new mixture of fuels, you must recalculate the maximum chlorine input using Equation 5 of § 63.7530. If the results of recalculating the maximum chlorine input using Equation 5 of § 63.7530 are higher than the maximum chlorine input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in § 63.7520 to demonstrate that the HCl emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in § 63.7530(c).

(5) If you demonstrate compliance with an applicable TSM emission limit through fuel analysis, and you plan to burn a new type of fuel, you must recalculate the TSM emission rate using Equation 10 of § 63.7530 according to the procedures specified in paragraphs (a)(5)(i) through (iii) of this section.

(i) You must determine the TSM concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to § 63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of TSM.

(iii) Recalculate the TSM emission rate from your boiler or process heater under these new conditions using Equation 10 of § 63.7530. The recalculated TSM emission rate must be less than the applicable emission limit.

(6) If you demonstrate compliance with an applicable TSM emission limit through performance testing, and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum TSM input using Equation 6 of § 63.7530. If the results of recalculating the maximum total selected metals input using Equation 6 of § 63.7530 are higher than the maximum TSM input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in § 63.7520 to demonstrate that the TSM emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in § 63.7530(c).

(7) If you demonstrate compliance with an applicable mercury emission limit through fuel analysis, and you plan to burn a new type of fuel, you must recalculate the mercury emission rate using Equation 11 of § 63.7530 according to the procedures specified in paragraphs (a)(7)(i) through (iii) of this section.

(i) You must determine the mercury concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to § 63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of mercury.

(iii) Recalculate the mercury emission rate from your boiler or process heater under these new conditions using Equation 11 of § 63.7530. The recalculated mercury emission rate must be less than the applicable emission limit.

(8) If you demonstrate compliance with an applicable mercury emission limit through performance testing, and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum mercury input using Equation 7 of § 63.7530. If the results of recalculating the maximum mercury input using Equation 7 of § 63.7530 are higher than the maximum mercury input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in § 63.7520 to demonstrate that the mercury emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in § 63.7530(c).

(9) If your unit is controlled with a fabric filter, and you demonstrate continuous compliance using a bag leak detection system, you must initiate corrective action within 1 hour of a bag leak detection system alarm and complete corrective actions according to your SSMP, and operate and maintain the fabric filter system such that the alarm does not sound more than 5 percent of the operating time during a 6-month period. You must also keep records of the date, time, and duration of each alarm, the time corrective action was initiated and completed, and a brief description of the cause of the alarm and the corrective action taken. You must also record the percent of the operating time during each 6-month period that the alarm sounds. In calculating this operating time percentage, if inspection of the fabric filter demonstrates that no corrective action is required, no alarm time is counted. If corrective action is required, each alarm shall be counted as a minimum of 1 hour. If you take longer than 1 hour to initiate corrective action, the alarm time shall be counted as the actual amount of time taken to initiate corrective action.

(10) If you have an applicable work practice standard for carbon monoxide, and you are required to install a CEMS according to § 63.7525(a), then you must meet the requirements in paragraphs (a)(10)(i) through (iii) of this section.

(i) You must continuously monitor carbon monoxide according to §§ 63.7525(a) and 63.7535.

(ii) Maintain a carbon monoxide emission level below your applicable carbon monoxide work practice standard in Table 1 to this subpart at all times except during periods of startup, shutdown, malfunction, and when your boiler or process heater is operating at less than 50 percent of rated capacity.

(iii) Keep records of carbon monoxide levels according to § 63.7555(b).

(b) You must report each instance in which you did not meet each emission limit, operating limit, and work practice standard in Tables 1 through 4 to this subpart that apply to you. You must also report each instance during a startup, shutdown, or malfunction when you did not meet each applicable emission limit, operating limit, and work practice standard. These instances are deviations from the emission limits and work practice standards in this subpart. These deviations must be reported according to the requirements in § 63.7550.

(c) During periods of startup, shutdown, and malfunction, you must operate in accordance with the SSMP as required in § 63.7505(e).

(d) Consistent with §§ 63.6(e)and 63.7(e)(1), deviations that occur during a period of startup, shutdown, or malfunction are not violations if you demonstrate to the EPA Administrator's satisfaction that you were operating in accordance with your SSMP. The EPA Administrator will determine whether deviations that occur during a period of startup, shutdown, or malfunction are violations, according to the provisions in § 63.6(e).

### § 63.7541 How do I demonstrate continuous compliance under the emission averaging provision?

(a) Following the compliance date, the owner or operator must demonstrate compliance with this subpart on a continuous basis by meeting the requirements of paragraphs (a)(1) through (4) of this section.

(1) For each calendar month, demonstrate compliance with the average weighted emissions limit for the existing large solid fuel boilers participating in the emissions averaging option as determined in § 63.7522(f) and (g);

(2) For each existing solid fuel boiler participating in the emissions averaging option that is equipped with a dry control system, maintain opacity at or below the applicable limit;

(3) For each existing solid fuel boiler participating in the emissions averaging option that is equipped with a wet scrubber, maintain the 3-hour average parameter values at or below the operating limits established during the most recent performance test; and

(4) For each existing solid fuel boiler participating in the emissions averaging option that has an approved alternative operating plan, maintain the 3-hour average parameter values at or below the operating limits established in the most recent performance test.

(b) Any instance where the owner or operator fails to comply with the continuous monitoring requirements in paragraphs (a)(1) through (4) of this section, except during periods of startup, shutdown, and malfunction, is a deviation.

## Notification, Reports, and Records

### § 63.7545 What notifications must I submit and when?

(a) You must submit all of the notifications in §§ 63.7(b) and (c), 63.8 (e), (f)(4) and (6), and 63.9 (b) through (h) that apply to you by the dates specified.

(b) As specified in § 63.9(b)(2), if you startup your affected source before November 12, 2004, you must submit an Initial Notification not later than 120 days after November 12, 2004. The Initial Notification must include the information required in paragraphs (b)(1) and (2) of this section, as applicable.

(1) If your affected source has an annual capacity factor of greater than 10 percent, your Initial Notification must include the information required by § 63.9(b)(2).

(2) If your affected source has a federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent such that the unit is in one of the limited use subcategories (the limited use solid fuel subcategory, the limited use liquid fuel subcategory, or the limited use gaseous fuel subcategory), your Initial Notification must include the information required by § 63.9(b)(2) and also a signed statement indicating your affected source has a federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent.

(c) As specified in § 63.9(b)(4) and (b)(5), if you startup your new or reconstructed affected source on or after November 12, 2004, you must submit an Initial Notification not later than 15 days after the actual date of startup of the affected source.

(d) If you are required to conduct a performance test you must submit a Notification of Intent to conduct a performance test at least 30 days before the performance test is scheduled to begin.

(e) If you are required to conduct an initial compliance demonstration as specified in § 63.7530(a), you must submit a Notification of Compliance Status according to § 63.9(h)(2)(ii). For each initial compliance demonstration, you must submit the Notification of Compliance Status, including all performance test results and fuel analyses, before the close of business on the 60th day following the completion of the performance test and/or other initial compliance demonstrations according to § 63.10(d)(2). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (9), as applicable.

(1) A description of the affected source(s) including identification of which subcategory the source is in, the capacity of the source, a description of the add-on controls used on the source description of the fuel(s) burned, and justification for the fuel(s) burned during the performance test.

(2) Summary of the results of all performance tests, fuel analyses, and calculations conducted to demonstrate initial compliance including all established operating limits.

(3) Identification of whether you are complying with the particulate matter emission limit or the alternative total selected metals emission limit.

(4) Identification of whether you plan to demonstrate compliance with each applicable emission limit through performance testing or fuel analysis.

(5) Identification of whether you plan to demonstrate compliance by emissions averaging.

(6) A signed certification that you have met all applicable emission limits and work practice standards.

(7) A summary of the carbon monoxide emissions monitoring data and the maximum carbon monoxide emission levels recorded during the performance test to show that you have met any applicable work practice standard in Table 1 to this subpart.

(8) If your new or reconstructed boiler or process heater is in one of the liquid fuel subcategories and burns only liquid fossil fuels other than residual oil either alone or in combination with gaseous fuels, you must submit a signed statement certifying this in your Notification of Compliance Status report.

(9) If you had a deviation from any emission limit or work practice standard, you must also submit a description of the deviation, the duration of the deviation, and the corrective action taken in the Notification of Compliance Status report.

### § 63.7550 What reports must I submit and when?

(a) You must submit each report in Table 9 to this subpart that applies to you.

(b) Unless the EPA Administrator has approved a different schedule for submission of reports under § 63.10(a), you must submit each report by the date in Table 9 to this subpart and according to the requirements in paragraphs (b)(1) through (5) of this section.

(1) The first compliance report must cover the period beginning on the compliance date that is specified for your affected source 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 compliance date that is specified for your source in § 63.7495.

(2) The first compliance report must be postmarked or delivered 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 your source in § 63.7495.

(3) Each subsequent compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) Each subsequent compliance report must be postmarked or delivered

no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(5) 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 semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), you may submit the first and subsequent compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (4) of this section.

(c) The compliance report must contain the information required in paragraphs (c)(1) through (11) of this section.

(1) Company name and address.

(2) Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report.

(3) Date of report and beginning and ending dates of the reporting period.

(4) The total fuel use by each affected source subject to an emission limit, for each calendar month within the semiannual reporting period, including, but not limited to, a description of the fuel and the total fuel usage amount with units of measure.

(5) A summary of the results of the annual performance tests and documentation of any operating limits that were reestablished during this test, if applicable.

(6) A signed statement indicating that you burned no new types of fuel. Or, if you did burn a new type of fuel, you must submit the calculation of chlorine input, using Equation 5 of § 63.7530, that demonstrates that your source is still within its maximum chlorine input level established during the previous performance testing (for sources that demonstrate compliance through performance testing) or you must submit the calculation of HCl emission rate using Equation 9 of § 63.7530 that demonstrates that your source is still meeting the emission limit for HCl emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel, you must submit the calculation of TSM input, using Equation 6 of § 63.7530, that demonstrates that your source is still within its maximum TSM input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of TSM emission rate using Equation 10 of § 63.7530 that demonstrates that your source is still meeting the emission limit for TSM emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel, you must submit the calculation of mercury input, using Equation 7 of § 63.7530, that demonstrates that your source is still within its maximum mercury input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of mercury emission rate using Equation 11 of § 63.7530 that demonstrates that your source is still meeting the emission limit for mercury emissions (for boilers or process heaters that demonstrate compliance through fuel analysis).

(7) If you wish to burn a new type of fuel and you can not demonstrate compliance with the maximum chlorine input operating limit using Equation 5 of § 63.7530, the maximum TSM input operating limit using Equation 6 of § 63.7530, or the maximum mercury input operating limit using Equation 7 of § 63.7530, you must include in the compliance report a statement indicating the intent to conduct a new performance test within 60 days of starting to burn the new fuel.

(8) The hours of operation for each boiler and process heater that is subject to an emission limit for each calendar month within the semiannual reporting period. This requirement applies only to limited use boilers and process heaters.

(9) If you had a startup, shutdown, or malfunction during the reporting period and you took actions consistent with your SSMP, the compliance report must include the information in § 63.10(d)(5)(i).

(10) If there are no deviations from any emission limits or operating limits in this subpart that apply to you, and there are no deviations from the requirements for work practice standards in this subpart, a statement that there were no deviations from the emission limits, operating limits, or work practice standards during the reporting period.

(11) If there were no periods during which the CMSs, including CEMS, COMS, and CPMS, were out of control as specified in § 63.8(c)(7), a statement that there were no periods during which the CMSs were out of control during the reporting period.

(d) For each deviation from an emission limit or operating limit in this subpart and for each deviation from the requirements for work practice standards in this subpart that occurs at an affected source where you are not using a CMSs to comply with that emission limit, operating limit, or work practice standard, the compliance report must contain the information in paragraphs (c)(1) through (10) of this section and the information required in paragraphs (d)(1) through (4) of this section. This includes periods of startup, shutdown, and malfunction.

(1) The total operating time of each affected source during the reporting period.

(2) A description of the deviation and which emission limit, operating limit, or work practice standard from which you deviated.

(3) Information on the number, duration, and cause of deviations (including unknown cause), as applicable, and the corrective action taken.

(4) A copy of the test report if the annual performance test showed a deviation from the emission limit for particulate matter or the alternative TSM limit, a deviation from the HCl emission limit, or a deviation from the mercury emission limit.

(e) For each deviation from an emission limitation and operating limit or work practice standard in this subpart occurring at an affected source where you are using a CMS to comply with that emission limit, operating limit, or work practice standard, you must include the information in paragraphs (c) (1) through (10) of this section and the information required in paragraphs (e) (1) through (12) of this section. This includes periods of startup, shutdown, and malfunction and any deviations from your site-specific monitoring plan as required in § 63.7505(d).

(1) The date and time that each malfunction started and stopped and description of the nature of the deviation (*i.e.*, what you deviated from).

(2) The date and time that each CMS was inoperative, except for zero (low-level) and high-level checks.

(3) The date, time, and duration that each CMS was out of control, including the information in § 63.8(c)(8).

(4) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of startup, shutdown, or malfunction or during another period.

(5) A summary of the total duration of the deviation during the reporting period and the total duration as a percent of the total source operating time during that reporting period.

(6) A breakdown of the total duration of the deviations during the reporting period into those that are due to startup, shutdown, control equipment problems,

process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of CMSs downtime during the reporting period and the total duration of CMS downtime as a percent of the total source operating time during that reporting period.

(8) An identification of each parameter that was monitored at the affected source for which there was a deviation, including opacity, carbon monoxide, and operating parameters for wet scrubbers and other control devices.

(9) A brief description of the source for which there was a deviation.

(10) A brief description of each CMS for which there was a deviation.

(11) The date of the latest CMS certification or audit for the system for which there was a deviation.

(12) A description of any changes in CMSs, processes, or controls since the last reporting period for the source for which there was a deviation.

(f) Each affected source that has obtained a title V operating permit pursuant to 40 CFR part 70 or 40 CFR part 71 must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a compliance report pursuant to Table 9 to this subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the compliance report includes all required information concerning deviations from any emission limit, operating limit, or work practice requirement in this subpart, submission of the compliance report satisfies any obligation to report the same deviations in the semiannual monitoring report. However, submission of a compliance report does not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.

(g) If you operate a new gaseous fuel unit that is subject to the work practice standard specified in Table 1 to this subpart, and you intend to use a fuel other than natural gas or equivalent to fire the affected unit, you must submit a notification of alternative fuel use within 48 hours of the declaration of a period of natural gas curtailment or supply interruption, as defined in § 63.7575. The notification must include the information specified in paragraphs (g)(1) through (5) of this section.

(1) Company name and address.

(2) Identification of the affected unit.

(3) Reason you are unable to use natural gas or equivalent fuel, including the date when the natural gas curtailment was declared or the natural gas supply interruption began.

(4) Type of alternative fuel that you intend to use.

(5) Dates when the alternative fuel use is expected to begin and end.

### § 63.7555 What records must I keep?

(a) You must keep records according to paragraphs (a)(1) through (3) of this section.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that you submitted, according to the requirements in § 63.10(b)(2)(xiv).

(2) The records in § 63.6(e)(3)(iii) through (v) related to startup, shutdown, and malfunction.

(3) Records of performance tests, fuel analyses, or other compliance demonstrations, performance evaluations, and opacity observations as required in § 63.10(b)(2)(viii).

(b) For each CEMS, CPMS, and COMS, you must keep records according to paragraphs (b)(1) through (5) of this section.

(1) Records described in § 63.10(b)(2)(vi) through (xi).

(2) Monitoring data for continuous opacity monitoring system during a performance evaluation as required in § 63.6(h)(7)(i) and (ii).

(3) Previous (*i.e.,* superseded) versions of the performance evaluation plan as required in § 63.8(d)(3).

(4) Request for alternatives to relative accuracy test for CEMS as required in § 63.8(f)(6)(i).

(5) Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period.

(c) You must keep the records required in Table 8 to this subpart including records of all monitoring data and calculated averages for applicable operating limits such as opacity, pressure drop, carbon monoxide, and pH to show continuous compliance with each emission limit, operating limit, and work practice standard that applies to you.

(d) For each boiler or process heater subject to an emission limit, you must also keep the records in paragraphs (d)(1) through (5) of this section.

(1) You must keep records of monthly fuel use by each boiler or process heater, including the type(s) of fuel and amount(s) used.

(2) You must keep records of monthly hours of operation by each boiler or process heater. This requirement applies only to limited-use boilers and process heaters.

(3) A copy of all calculations and supporting documentation of maximum chlorine fuel input, using Equation 5 of § 63.7530, that were done to demonstrate continuous compliance with the HCl emission limit, for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of HCl emission rates, using Equation 9 of § 63.7530, that were done to demonstrate compliance with the HCl emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum chlorine fuel input or HCl emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate chlorine fuel input, or HCl emission rate, for each boiler and process heater.

(4) A copy of all calculations and supporting documentation of maximum TSM fuel input, using Equation 6 of § 63.7530, that were done to demonstrate continuous compliance with the TSM emission limit for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of TSM emission rates, using Equation 10 of § 63.7530, that were done to demonstrate compliance with the TSM emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum TSM fuel input or TSM emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate TSM fuel input, or TSM emission rates, for each boiler and process heater.

(5) A copy of all calculations and supporting documentation of maximum mercury fuel input, using Equation 7 of § 63.7530, that were done to demonstrate continuous compliance with the mercury emission limit for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of mercury emission rates, using Equation 11 of § 63.7530, that were done to demonstrate compliance with the mercury emission limit. Supporting documentation should

include results of any fuel analyses and basis for the estimates of maximum mercury fuel input or mercury emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate mercury fuel input, or mercury emission rates, for each boiler and process heater.

(e) If your boiler or process heater is subject to an emission limit or work practice standard in Table 1 to this subpart and has a federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent such that the unit is in one of the limited use subcategories, you must keep the records in paragraphs (e)(1) and (2) of this section.

(1) A copy of the federally enforceable permit that limits the annual capacity factor of the source to less than or equal to 10 percent.

(2) Fuel use records for the days the boiler or process heater was operating.

### § 63.7560 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review, according to § 63.10(b)(1).

(b) As specified in § 63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 63.10(b)(1). You can keep the records off site for the remaining 3 years.

## Other Requirements and Information

### § 63.7565 What parts of the General Provisions apply to me?

Table 10 to this subpart shows which parts of the General Provisions in §§ 63.1 through 63.15 apply to you.

### § 63.7570 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by U.S. EPA, or a delegated authority such as your State, local, or tribal agency. If the EPA Administrator has delegated authority to your State, local, or tribal agency, then that agency (as well as the U.S. EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this subpart is delegated to your State, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under 40 CFR part 63, subpart E, the authorities listed in paragraphs (b)(1) through (5) of this section are retained by the EPA Administrator and are not transferred to the State, local, or tribal agency, however, the U.S. EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

(1) Approval of alternatives to the non-opacity emission limits and work practice standards in § 63.7500(a) and (b) under § 63.6(g).

(2) Approval of alternative opacity emission limits in § 63.7500(a) under § 63.6(h)(9).

(3) Approval of major change to test methods in Table 5 to this subpart under § 63.7(e)(2)(ii) and (f) and as defined in § 63.90.

(4) Approval of major change to monitoring under § 63.8(f) and as defined in § 63.90.

(5) Approval of major change to recordkeeping and reporting under § 63.10(f) and as defined in § 63.90.

### § 63.7575 What definitions apply to this subpart?

Terms used in this subpart are defined in the CAA, in § 63.2 (the General Provisions), and in this section as follows:

*Annual capacity factor* means 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.

*Bag leak detection system* means an instrument that is capable of monitoring particulate matter 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.

*Biomass fuel* means unadulterated wood as defined in this subpart, wood residue, and wood products (*e.g.*, trees, tree stumps, tree limbs, bark, lumber, sawdust, sanderdust, chips, scraps, slabs, millings, and shavings); animal litter; vegetative agricultural and silvicultural materials, such as logging residues (slash), nut and grain hulls and chaff (*e.g.*, almond, walnut, peanut, rice, and wheat), bagasse, orchard prunings, corn stalks, coffee bean hulls and grounds.

*Blast furnace gas fuel-fired boiler or process heater* means an industrial/commercial/institutional boiler or process heater that receives 90 percent or more of its total heat input (based on an annual average) from blast furnace gas.

*Boiler* means an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water. Waste heat boilers are excluded from this definition.

*Coal* means all solid fuels classifiable as anthracite, bituminous, sub-bituminous, or lignite by the American Society for Testing and Materials in ASTM D388–991$^{\in 1}$, ‘‘Standard Specification for Classification of Coals by Rank[1]’’ (incorporated by reference, see § 63.14(b)), coal refuse, and petroleum coke. Synthetic fuels derived from coal for the purpose of creating useful heat including but not limited to, solvent-refined coal, coal-oil mixtures, and coal-water mixtures, for the purposes of this subpart. Coal derived gases are excluded from this definition.

*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 (6,000 Btu per pound) on a dry basis.

*Commercial/institutional boiler* means a boiler used in commercial establishments or institutional establishments such as medical centers, research centers, institutions of higher education, hotels, and laundries to provide electricity, steam, and/or hot water.

*Construction/demolition material* means waste building material that result from the construction or demolition operations on houses and commercial and industrial buildings.

*Deviation.* (1) Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(i) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard;

(ii) 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; or

(iii) Fails to meet any emission limit, operating limit, or work practice standard in this subpart during startup, shutdown, or malfunction, regardless or whether or not such failure is permitted by this subpart.

(2) A deviation is not always a violation. The determination of whether a deviation constitutes a violation of the

standard is up to the discretion of the entity responsible for enforcement of the standards.

*Distillate oil* means fuel oils, including recycled oils, that comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D396–02a, ''Standard Specifications for Fuel Oils[1]'' (incorporated by reference, see § 63.14(b)).

*Dry scrubber* means 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. Sorbent injection systems in fluidized bed boilers and process heaters are included in this definition.

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

*Electrostatic precipitator* means an add-on air pollution control device used to capture particulate matter by charging the particles using an electrostatic field, collecting the particles using a grounded collecting surface, and transporting the particles into a hopper.

*Fabric filter* means an add-on air pollution control device used to capture particulate matter by filtering gas streams through filter media, also known as a baghouse.

*Federally enforceable* means all limitations and conditions that are enforceable by the EPA Administrator, including the requirements of 40 CFR parts 60 and 61, 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.

*Firetube boiler* means a boiler in which hot gases of combustion pass through the tubes and water contacts the outside surfaces of the tubes.

*Fossil fuel* means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such materials.

*Fuel type* means each category of fuels that share a common name or classification. Examples include, but are not limited to, bituminous coal, subbituminous coal, lignite, anthracite, biomass, construction/demolition material, salt water laden wood, creosote treated wood, tires, residual oil. Individual fuel types received from different suppliers are not considered new fuel types except for construction/demolition material.

*Gaseous fuel* includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, refinery gas, and biogas. Blast furnace gas is exempted from this definition.

*Heat input* means heat derived from combustion of fuel in a boiler or process heater and does not include the heat input from preheated combustion air, recirculated flue gases, or exhaust gases from other sources such as gas turbines, internal combustion engines, kilns, etc.

*Hot water heater* means a closed vessel with a capacity of no more than 120 U.S. gallons in which water is heated by combustion of gaseous or liquid fuel and is withdrawn for use external to the vessel at pressures not exceeding 160 psig, including the apparatus by which the heat is generated and all controls and devices necessary to prevent water temperatures from exceeding 210°F (99°C).

*Industrial boiler* means a boiler used in manufacturing, processing, mining, and refining or any other industry to provide steam, hot water, and/or electricity.

*Large gaseous fuel subcategory* includes any watertube boiler or process heater that burns gaseous fuels not combined with any solid fuels, burns liquid fuel only during periods of gas curtailment or gas supply emergencies, has a rated capacity of greater than 10 MMBtu per hour heat input, and has an annual capacity factor of greater than 10 percent.

*Large liquid fuel subcategory* includes any watertube boiler or process heater that does not burn any solid fuel and burns any liquid fuel either alone or in combination with gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and has an annual capacity factor of greater than 10 percent. Large gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply emergencies are not included in this definition.

*Large solid fuel subcategory* includes any watertube boiler or process heater that burns any amount of solid fuel either alone or in combination with liquid or gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and has an annual capacity factor of greater than 10 percent.

*Limited use gaseous fuel subcategory* includes any watertube boiler or process heater that burns gaseous fuels not combined with any liquid or solid fuels, burns liquid fuel only during periods of gas curtailment or gas supply emergencies, has a rated capacity of greater than 10 MMBtu per hour heat input, and has a federally enforceable annual average capacity factor of equal to or less than 10 percent.

*Limited use liquid fuel subcategory* includes any watertube boiler or process heater that does not burn any solid fuel and burns any liquid fuel either alone or in combination with gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and has a federally enforceable annual average capacity factor of equal to or less than 10 percent. Limited use gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply emergencies are not included in this definition.

*Limited use solid fuel subcategory* includes any watertube boiler or process heater that burns any amount of solid fuel either alone or in combination with liquid or gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and has a federally enforceable annual average capacity factor of equal to or less than 10 percent.

*Liquid fossil fuel* means petroleum, distillate oil, residual oil and any form of liquid fuel derived from such material.

*Liquid fuel* includes, but is not limited to, distillate oil, residual oil, waste oil, and process liquids.

*Minimum pressure drop* means 90 percent of the lowest test-run average pressure drop measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

*Minimum scrubber effluent pH* means 90 percent of the lowest test-run average effluent pH measured at the outlet of the wet scrubber according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable hydrogen chloride emission limit.

*Minimum scrubber flow rate* means 90 percent of the lowest test-run average flow rate measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

*Minimum sorbent flow rate* means 90 percent of the lowest test-run average sorbent (or activated carbon) flow rate measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits.

*Minimum voltage or amperage* means 90 percent of the lowest test-run average voltage or amperage to the electrostatic precipitator measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits.

*Natural gas* means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) Liquid petroleum gas, as defined by the American Society for Testing and Materials in ASTM D1835–03a, ''Standard Specification for Liquid Petroleum Gases'' (incorporated by reference, see § 63.14(b)).

*Opacity* means the degree to which emissions reduce the transmission of light and obscure the view of an object in the background.

*Particulate matter* means any finely divided solid or liquid material, other than uncombined water, as measured by the test methods specified under this subpart, or an alternative method.

*Period of natural gas curtailment or supply interruption* means a period of time during which the supply of natural gas to an affected facility is halted for reasons beyond the control of the facility. An increase in the cost or unit price of natural gas does not constitute a period of natural gas curtailment or supply interruption.

*Process heater* means an enclosed device using controlled flame, that is not a boiler, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not directly come into 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.

*Residual oil* means crude oil, and all fuel oil numbers 4, 5 and 6, as defined by the American Society for Testing and Materials in ASTM D396–02a, ''Standard Specifications for Fuel Oils [1]'' (incorporated by reference, see § 63.14(b)).

*Responsible official* means responsible official as defined in 40 CFR 70.2.

*Small gaseous fuel subcategory* includes any firetube boiler that burns gaseous fuels not combined with any solid fuels and burns liquid fuel only during periods of gas curtailment or gas supply emergencies, and any boiler or process heater that burns gaseous fuels not combined with any solid fuels, burns liquid fuel only during periods of gas curtailment or gas supply emergencies, and has a rated capacity of less than or equal to 10 MMBtu per hour heat input.

*Small liquid fuel subcategory* includes any firetube boiler that does not burn any solid fuel and burns any liquid fuel either alone or in combination with gaseous fuels, and any boiler or process heater that does not burn any solid fuel and burns any liquid fuel either alone or in combination with gaseous fuels, and has a rated capacity of less than or equal to 10 MMBtu per hour heat input. Small gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply emergencies are not included in this definition.

*Small solid fuel subcategory* includes any firetube boiler that burns any amount of solid fuel either alone or in combination with liquid or gaseous fuels, and any other boiler or process heater that burns any amount of solid fuel either alone or in combination with liquid or gaseous fuels and has a rated capacity of less than or equal to 10 MMBtu per hour heat input.

*Solid fuel* includes, but is not limited to, coal, wood, biomass, tires, plastics, and other nonfossil solid materials.

*Temporary boiler* means any gaseous or liquid fuel boiler that is designed to, and is capable of, being carried or moved from one location to another. A temporary boiler that remains at a location for more than 180 consecutive days is no longer considered to be a temporary boiler. Any temporary boiler that replaces a temporary boiler at a location and is intended to perform the same or similar function will be included in calculating the consecutive time period.

*Total selected metals* means the combination of the following metallic HAP: arsenic, beryllium, cadmium, chromium, lead, manganese, nickel and selenium.

*Unadulterated wood* means wood or wood products that have not been painted, pigment-stained, or pressure treated with compounds such as chromate copper arsenate, pentachlorophenol, and creosote. Plywood, particle board, oriented strand board, and other types of wood products bound by glues and resins are included in this definition.

*Waste heat boiler* means a device that recovers normally unused energy and converts it to usable heat. Waste heat boilers incorporating duct or supplemental burners that are designed to supply 50 percent or more of the total rated heat input capacity of the waste heat boiler are not considered waste heat boilers, but are considered boilers. Waste heat boilers are also referred to as heat recovery steam generators.

*Watertube boiler* means a boiler in which water passes through the tubes and hot gases of combustion pass over the outside surfaces of the tubes.

*Wet scrubber* means 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 particulate matter and/or to absorb and neutralize acid gases, such as hydrogen chloride.

*Work practice standard* means any design, equipment, work practice, or operational standard, or combination thereof, that is promulgated pursuant to section 112(h) of the CAA.

## Tables to Subpart DDDDD of Part 63

### TABLE 1 TO SUBPART DDDDD OF PART 63.—EMISSION LIMITS AND WORK PRACTICE STANDARDS

As stated in § 63.7500, you must comply with the following applicable emission limits and work practice standards:

| If your boiler or process heater is in this subcategory . . . | For the following pollutants . . . | You must meet the following emission limits and work practice standards . . . |
|---|---|---|
| 1. New or reconstructed large solid fuel | a. Particulate Matter (or Total Selected Metals). | 0.025 lb per MMBtu of heat input; or (0.0003 lb per MMBtu of heat input). |
| | b. Hydrogen Chloride | 0.02 lb per MMBtu of heat input. |
| | c. Mercury | 0.000003 lb per MMBtu of heat input. |
| | d. Carbon Monoxide | 400 ppm by volume on a dry basis corrected to 7 percent oxygen (30-day rolling average for units 100 MMBtu/hr or greater, 3-run average for units less than 100 MMBtu/hr). |

## TABLE 1 TO SUBPART DDDDD OF PART 63.—EMISSION LIMITS AND WORK PRACTICE STANDARDS—Continued

As stated in § 63.7500, you must comply with the following applicable emission limits and work practice standards:

| If your boiler or process heater is in this subcategory . . . | For the following pollutants . . . | You must meet the following emission limits and work practice standards . . . |
|---|---|---|
| 2. New or reconstructed limited use solid fuel | a. Particulate Matter (or Total Selected Metals). | 0.025 lb per MMBtu of heat input; or (0.0003 lb per MMBtu of heat input). |
| | b. Hydrogen Chloride | 0.02 lb per MMBtu of heat input. |
| | c. Mercury | 0.000003 lb per MMBtu of heat input. |
| | d. Carbon Monoxide | 400 ppm by volume on a dry basis corrected to 7 percent oxygen (3-run average). |
| 3. New or reconstructed small solid fuel | a. Particulate Matter (or Total Selected Metals). | 0.025 lb per MMBtu of heat input; or (0.0003 lb per MMBtu of heat input). |
| | b. Hydrogen Chloride | 0.02 lb per MMBtu of heat input. |
| | c. Mercury | 0.000003 lb per MMBtu of heat input. |
| 4. New reconstructed large liquid fuel | a. Particulate Matter | 0.03 lb per MMBtu of heat input. |
| | b. Hydrogen Chloride | 0.0005 lb per MMBtu of heat input. |
| | c. Carbon Monoxide | 400 ppm by volume on a dry basis corrected to 3 percent oxygen (30-day rolling average for units 100 MMBtu/hr or greater, 3-run average for units less than 100 MMBtu/hr). |
| 5. New or reconstructed limited use liquid fuel | a. Particulate Matter | 0.03 lb per MMBtu of heat input. |
| | b. Hydrogen Chloride | 0.0009 lb per MMBtu of heat input. |
| | c. Carbon Monoxide | 400 ppm by volume on a dry basis liquid corrected to 3 percent oxygen (3-run average). |
| 6. New or reconstructed small liquid fuel | a. Particulate Matter | 0.03 lb per MMBtu of heat input. |
| | b. Hydrogen Chloride | 0.0009 lb per MMBtu of heat input. |
| 7. New reconstructed large gaseous fuel | Carbon Monoxide | 400 ppm by volume on a dry basis corrected to 3 percent oxygen (30-day rolling average for units 100 MMBtu/hr or greater, 3-run average for units less than 100 MMBtu/hr). |
| 8. New or reconstructed limited use gaseous fuel. | Carbon Monoxide | 400 ppm by volume on a dry basis corrected to 3 percent oxygen (3-run average). |
| 9. Existing large solid fuel | a. Particulate Matter (or Total Selected Metals). | 0.07 lb per MMBtu of heat input; or (0.001 lb per MMBtu of heat input). |
| | b. Hydrogen Chloride | 0.09 lb per MMBtu of heat input. |
| | c. Mercury | 0.000009 lb per MMBtu of heat input. |
| 10. Existing limited use solid fuel | Particulate Matter (or Total Selected Metals) | 0.21 lb per MMBtu of heat input; or (0.004 lb per MMBtu of heat input). |

## TABLE 2 TO SUBPART DDDDD OF PART 63.—OPERATING LIMITS FOR BOILERS AND PROCESS HEATERS WITH PARTICULATE MATTER EMISSION LIMITS

As stated in § 63.7500, you must comply with the applicable operating limits:

| If you demonstrate compliance with applicable particulate matter emission limits using . . . | You must meet these operating limits . . . |
|---|---|
| 1. Wet scrubber control | a. Maintain the minimum pressure drop and liquid flow-rate at or above the operating levels established during the performance test according to § 63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for particulate matter. |
| 2. Fabric filter control | a. Install and operate a bag leak detection system according to § 63.7525 and operate the fabric filter such that the bag leak detection system alarm does not sound more than 5 percent of the operating time during each 6-month period; or |
| | b. This option is for boilers and process heaters that operate dry control systems. Existing boilers and process heaters must maintain opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent. New boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (1-hour block average). |
| 3. Electrostatic precipitator control | a. This option is for boilers and process heaters that operate dry control systems. Existing boilers and process heaters must maintain opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent. New boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (1-hour block average); or |

### TABLE 2 TO SUBPART DDDDD OF PART 63.—OPERATING LIMITS FOR BOILERS AND PROCESS HEATERS WITH PARTICULATE MATTER EMISSION LIMITS—Continued

As stated in § 63.7500, you must comply with the applicable operating limits:

| If you demonstrate compliance with applicable particulate matter emission limits using . . . | You must meet these operating limits . . . |
|---|---|
| | b. This option is only for boilers and process heaters that operate additional wet control systems. Maintain the minimum voltage and secondary current or total power input of the electrostatic precipitator at or above the operating limits established during the performance test according to § 63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for particulate matter. |
| 4. Any other control type | This option is for boilers and process heaters that operate dry control systems. Existing boilers and process heaters must maintain opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent. New boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (1-hour block average). |

### TABLE 3 TO SUBPART DDDDD OF PART 63.—OPERATING LIMITS FOR BOILERS AND PROCESS HEATERS WITH MERCURY EMISSION LIMITS AND BOILERS AND PROCESS HEATERS THAT CHOOSE TO COMPLY WITH THE ALTERNATIVE TOTAL SELECTED METALS EMISSION LIMITS

As stated in § 63.7500, you must comply with the applicable operating limits:

| If you demonstrate compliance with applicable mercury and/or total selected metals emission limits using . . . | You must meet these operating limits . . . |
|---|---|
| 1. Wet scrubber control | Maintain the minimum pressure drop and liquid flow-rate at or above the operating levels established during the performance test according to § 63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limits for mercury and/or total selected metals. |
| 2. Fabric filter control | a. Install and operate a bag leak detection system according to § 63.7525 and 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; or |
| | b. This option is for boilers and process heaters that operate dry control systems. Existing sources must maintain opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent. New sources must maintain opacity to less than or equal to 10 percent opacity (1-hour block average). |
| 3. Electrostatic precipitator control | a. This option is for boilers and process heaters that operate dry control systems. Existing sources must maintain opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent. New sources must maintain opacity to less than or equal to 10 percent opacity (1-hour block average); or |
| | b. This option is only for boilers and process heaters that operate additional wet control systems. Maintain the minimum voltage and secondary current or total power input of the electrostatic precipitator at or above the operating limits established during the performance test according to § 63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limits for mercury and/or total selected metals. |
| 4. Dry scrubber or carbon injection control | Maintain the minimum sorbent or carbon injection rate at or above the operating levels established during the performance test according to § 63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for mercury. |
| 5. Any other control type | This option is only for boilers and process heaters that operate dry control systems. Existing sources must maintain opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent. New sources must maintain opacity to less than or equal to 10 percent opacity (1-hour block average). |
| 6. Fuel analysis | Maintain the fuel type or fuel mixture such that the mercury and/or total selected metals emission rates calculated according to § 63.7530(d)(4) and/or (5) is less than the applicable emission limits for mercury and/or total selected metals. |

## TABLE 4 TO SUBPART DDDDD OF PART 63.—OPERATING LIMITS FOR BOILERS AND PROCESS HEATERS WITH HYDROGEN CHLORIDE EMISSION LIMITS

As stated in § 63.7500, you must comply with the following applicable operating limits:

| If you demonstrate compliance with applicable hydrogen chloride emission limits using . . . | You must meet these operating limits . . . |
|---|---|
| 1. Wet scrubber control | Maintain the minimum scrubber effluent pH, pressure drop, and liquid flow-rate at or above the operating levels established during the performance test according to § 63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for hydrogen chloride. |
| 2. Dry scrubber control | Maintain the minimum sorbent injection rate at or above the operating levels established during the performance test according to § 63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for hydrogen chloride. |
| 3. Fuel analysis | Maintain the fuel type or fuel mixture such that the hydrogen chloride emission rate calculated according to § 63.7530(d)(3) is less than the applicable emission limit for hydrogen chloride. |

## TABLE 5 TO SUBPART DDDDD OF PART 63.—PERFORMANCE TESTING REQUIREMENTS

As stated in § 63.7520, you must comply with the following requirements for performance test for existing, new or reconstructed affected sources:

| To conduct a performance test for the following pollutant . . . | You must . . . | Using . . . |
|---|---|---|
| 1. Particulate Matter | a. Select sampling ports location and the number of traverse points. | Method 1 in appendix A to part 60 of this chapter. |
| | b. Determine velocity and volumetric flow-rate of the stack gas. | Method 2, 2F, or 2G in appendix A to part 60 of this chapter. |
| | c. Determine oxygen and carbon dioxide concentrations of the stack gas. | Method 3A or 3B in appendix A to part 60 of this chapter, or ASME PTC 19, Part 10 (1981) (IBR, see § 63.14(i)). |
| | d. Measure the moisture content of the stack gas. | Method 4 in appendix A to part 60 of this chapter. |
| | e. Measure the particulate matter emission concentration. | Method 5 or 17 (positive pressure fabric filters must use Method 5D) in appendix A to part 60 of this chapter. |
| | f. Convert emissions concentration to lb per MMBtu emission rates. | Method 19 F-factor methodology in appendix A to part 60 of this chapter. |
| 2. Total selected metals | a. Select sampling ports location and the number of traverse points. | Method 1 in appendix A to part 60 of this chapter. |
| | b. Determine velocity and volumetric flow-rate of the stack gas. | Method 2, 2F, or 2G in appendix A to part 60 of this chapter. |
| | c. Determine oxygen and carbon dioxide concentrations of the stack gas. | Method 3A or 3B in appendix A to part 60 of this chapter, or ASME PTC 19, Part 10 (1981) (IBR, see § 63.14(i)). |
| | d. Measure the moisture content of the stack gas. | Method 4 in appendix A to part 60 of this chapter. |
| | e. Measure the total selected metals emission concentration. | Method 29 in appendix A to part 60 of this chapter. |
| | f. Convert emissions concentration to lb per MMBtu emission rates. | Method 19 F-factor methodology in appendix A to part 60 of this chapter. |
| 3. Hydrogen chloride | a. Select sampling ports location and the number of traverse points. | Method 1 in appendix A to part 60 of this chapter. |
| | b. Determine velocity and volumetric flow-rate of the stack gas. | Method 2, 2F, or 2G in appendix A to part 60 of this chapter. |
| | c. Determine oxygen and carbon dioxide concentrations of the stack gas. | Method 3A or 3B in appendix A to part 60 of this chapter, or ASME PTC 19, Part 10 (1981) (IBR, see § 63.14(i)). |
| | d. Measure the moisture content of the stack gas. | Method 4 in appendix A to part 60 of this chapter. |
| | e. Measure the hydrogen chloride emission concentration. | Method 26 or 26A in appendix A to part 60 of this chapter. |
| | f. Convert emissions concentration to lb per MMBtu emission rates. | Method 19 F-factor methodology in appendix A to part 60 of this chapter. |
| 4. Mercury | a. Select sampling ports location and the number of traverse points. | Method 1 in appendix A to part 60 of this chapter. |
| | b. Determine velocity and volumetric flow-rate of the stack gas. | Method 2, 2F, or 2G in appendix A to part 60 of this chapter. |
| | c. Determine oxygen and carbon dioxide concentrations of the stack gas. | Method 3A or 3B in appendix A to part 60 of this chapter, or ASME PTC 19, Part 10 (1981) (IBR, see § 62.14(i)). |

### TABLE 5 TO SUBPART DDDDD OF PART 63.—PERFORMANCE TESTING REQUIREMENTS—Continued

As stated in § 63.7520, you must comply with the following requirements for performance test for existing, new or reconstructed affected sources:

| To conduct a performance test for the following pollutant . . . | You must . . . | Using . . . |
|---|---|---|
| | d. Measure the moisture content of the stack gas. | Method 4 in appendix A to part 60 of this chapter. |
| | e. Measure the mercury emission concentration. | Method 29 in appendix A to part 60 of this chapter or Method 101A in appendix B to part 61 of this chapter or ASTM Method D6784–02 (IBR, see § 63.14(b)). |
| | f. Convert emissions concentration to lb per MMBtu emission rates. | Method 19 F-factor methodology in appendix A to part 60 of this chapter. |
| 5. Carbon Monoxide | a. Select the sampling ports location and the number of traverse points. | Method 1 in appendix A to part 60 of this chapter. |
| | b. Determine oxygen and carbon dioxide concentrations of the stack gas. | Method 3A or 3B in appendix A to part 60 of this chapter, or ASTM D6522–00 (IBR, see § 63.14(b)), or ASME PTC 19, Part 10 (1981) (IBR, see § 63.14(i)). |
| | c. Measure the moisture content of the stack gas. | Method 4 in appendix A to part 60 of this chapter. |
| | d. Measure the carbon monoxide emission concentration. | Method 10, 10A, or 10B in appendix A to part 60 of this chapter, or ASTM D6522–00 (IBR, see § 63.14(b)) when the fuel is natural gas. |

### TABLE 6 TO SUBPART DDDDD OF PART 63.—FUEL ANALYSIS REQUIREMENTS

As stated in § 63.7521, you must comply with the following requirements for fuel analysis testing for existing, new or reconstructed affected sources:

| To conduct a fuel analysis for the following pollutant . . . | You must . . . | Using . . . |
|---|---|---|
| 1. Mercury | a. Collect fuel samples | Procedure in § 63.7521(c) or ASTM D2234–$00^{\epsilon 1}$ (for coal)(IBR, see § 63.14(b)) or ASTM D6323–98 (2003)(for biomass)(IBR, see § 63.14(b)) or equivalent. |
| | b. Composite fuel samples | Procedure in § 63.7521(d) or equivalent. |
| | c. Prepare composited fuel samples | SW–846–3050B (for solid samples) or SW–846–3020A (for liquid samples) or ASTM D2013–01 (for coal) (IBR, see § 63.14(b)) or ASTM D5198–92 (2003) (for biomass)(IBR, see § 63.14(b)) or equivalent. |
| | d. Determine heat content of the fuel type | ASTM D5865–03a (for coal)(IBR, see § 63.14(b)) or ASTM E711–87 (1996) (for biomass)(IBR, see § 63.14(b)) or equivalent. |
| | e. Determine moisture content of the fuel type | ASTM D3173–02 (IBR, see § 63.14(b)) or ASTM E871–82 (1998)(IBR, see § 63.14(b)) or equivalent. |
| | f. Measure mercury concentration in fuel sample. | ASTM D3684–01 (for coal)(IBR, see § 63.14(b)) or SW–846–7471A (for solid samples) or SW–846 7470A (for liquid samples). |
| | g. Convert concentrations into units of pounds of pollutant per MMBtu of heat content. | |
| 2. Total selected metals | a. Collect fuel samples | Procedure in § 63.7521(c) or ASTM D2234–$00^{\epsilon 1}$ (for coal)(IBR, see § 63.14(b)) or ASTM D6323–98 (2003) (for biomass)(IBR, see § 63.14(b)) or equivalent. |
| | b. Composite fuel samples | Procedure in § 63.7521(d) or equivalent. |
| | c. Prepare composited fuel samples | SW–846–3050B (for solid samples) or SW–846–3020A (for liquid samples) or ASTM D2013–01 (for coal)(IBR, see § 63.14(b)) or ASTM D5198–92 (2003)(for biomass)(IBR, see § 63.14(b)) or equivalent. |
| | d. Determine heat content of the fuel type | ASTM D5865–03a (for coal)(IBR, see § 63.14(b)) or ASTM E 711–87 (for biomass)(IBR, see § 63.14(b)) or equivalent. |
| | e. Determine moisture content of the fuel type | ASTM D3173–02 (IBR, see § 63.14(b)) or ASTM E871 (IBR, see § 63.14(b)) or equivalent. |

## TABLE 6 TO SUBPART DDDDD OF PART 63.—FUEL ANALYSIS REQUIREMENTS—Continued

As stated in § 63.7521, you must comply with the following requirements for fuel analysis testing for existing, new or reconstructed affected sources:

| To conduct a fuel analysis for the following pollutant . . . | You must . . . | Using . . . |
|---|---|---|
| | f. Measure total selected metals concentration in fuel sample. | SW–846–6010B or ASTM D3683–94 (2000) (for coal) (IBR, see § 63.14(b)) or ASTM E885–88 (1996) (for biomass)(IBR, see § 63.14(b)). |
| | g. Convert concentrations into units of pounds of pollutant per MMBtu of heat content. | |
| 3. Hydrogen chloride | a. Collect fuel samples | Procedure in § 63.7521(c) or ASTM D2234$^{\in 1}$ (for coal)(IBR, see § 63.14(b)) or ASTM D6323–98 (2003) (for biomass)(IBR, see § 63.14(b)) or equivalent. |
| | b. Composite fuel samples | Procedure in § 63.7521(d) or equivalent. |
| | c. Prepare composited fuel samples | SW–846–3050B (for solid samples) or SW–846–3020A (for liquid samples) or ASTM D2013–01 (for coal)(IBR, see § 63.14(b)) or ASTM D5198–92 (2003) (for biomass)(IBR, see § 63.14(b)) or equivalent. |
| | d. Determine heat content of the fuel type | ASTM D5865–03a (for coal)(IBR, see § 63.14(b)) or ASTM E711–87 (1996) (for biomass)(IBR, see § 63.14(b)) or equivalent. |
| | e. Determine moisture content of the fuel type | ASTM D3173–02 (IBR, see § 63.14(b)) or ASTM E871–82 (1998)(IBR, see § 63.14(b)) or equivalent. |
| | f. Measure chlorine concentration in fuel sample. | SW–846–9250 or ASTM E776–87 (1996) (for biomass)(IBR, see § 63.14(b)) or equivalent. |
| | g. Convert concentrations into units of pounds of pollutant per MMBtu of heat content. | |

## TABLE 7 TO SUBPART DDDDD OF PART 63.—ESTABLISHING OPERATING LIMITS

As stated in § 63.7520, you must comply with the following requirements for establishing operating limits:

| If you have an applicable emission limit for . . . | And your operating limits are based on . . . | You must . . . | Using . . . | According to the following requirements |
|---|---|---|---|---|
| 1. Particulate matter, mercury, or total selected metals. | a. Wet scrubber operating parameters. | i. Establish a site-specific minimum pressure drop and minimum flow rate operating limit according to § 63.7530(c). | (1) Data from the pressure drop and liquid flow rate monitors and the particulate matter, mercury, or total selected metals performance test. | (a) You must collect pressure drop and liquid flow-rate data every 15 minutes during the entire period of the performance tests;<br>(b) Determine the average pressure drop and liquid flow-rate for each individual test run in the three-run performance test by computing the average of all the 15-minute readings taken during each test run. |
| | b. Electrostatic precipitator operating parameters (option only for units with additional wet scrubber control). | i. Establish a site-specific minimum voltage and secondary current or total power input according to § 63.7530(c). | (1) Data from the pressure drop and liquid flow rate monitors and the particulate matter, mercury, or total selected metals performance test. | (a) You must collect voltage and secondary current or total power input data every 15 minutes during the entire period of the performance tests;<br>(b) Determine the average voltage and secondary current or total power input for each individual test run in the three-run performance test by computing the average of all the 15-minute readings taken during each test run. |

## TABLE 7 TO SUBPART DDDDD OF PART 63.—ESTABLISHING OPERATING LIMITS—Continued

As stated in § 63.7520, you must comply with the following requirements for establishing operating limits:

| If you have an applicable emission limit for . . . | And your operating limits are based on . . . | You must . . . | Using . . . | According to the following requirements |
|---|---|---|---|---|
| 2. Hydrogen Chloride ... | a. Wet scrubber operating parameters. | i. Establish a site-specific minimum pressure drop and minimum flow rate operating limit according to § 63.7530(c). | (1) Data from the pH, pressure drop, and liquid flow-rate monitors and the hydrogen chloride performance test. | (a) You must collect pH, pressure drop, and liquid flow-rate data every 15 minutes during the entire period of the performance tests;<br>(b) Determine the average pH, pressure drop, and liquid flow-rate for each individual test run in the three-run performance test by computing the average of all the 15-minute readings taken during each test run. |
|  | b. Dry scrubber operating parameters. | i. Establish a site-specific minimum sorbent injection rate operating limit according to § 63.7530(c). | (1) Data from the sorbent injection rate monitors and hydrogen chloride performance test. | (a) You must collect sorbent injection rate data every 15 minutes during the entire period of the performance tests;<br>(b) Determine the average sorbent injection rate for each individual test run in the three-run performance test by computing the average of all the 15-minute readings taken during each test run. |

## TABLE 8 TO SUBPART DDDDD OF PART 63.—DEMONSTRATING CONTINUOUS COMPLIANCE

As stated in § 63.7540, you must show continuous compliance with the emission limitations for affected sources according to the following:

| If you must meet the following operating limits or work practice standards . . . | You must demonstrate continuous compliance by . . . |
|---|---|
| 1. Opacity | a. Collecting the opacity monitoring system data according to §§ 63.7525(b) and 63.7535; and<br>b. Reducing the opacity monitoring data to 6-minute averages; and<br>c. Maintaining opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent for existing sources; or maintaining opacity to less than or equal to 10 percent (1-hour block average) for new sources. |
| 2. Fabric Filter Bag Leak Detection Operation | Installing and operating a bag leak detection system according to § 63.7525 and operating the fabric filter such that the requirements in § 63.7540(a)(9) are met. |
| 3. Wet Scrubber Pressure Drop and Liquid Flow-rate | a. Collecting the pressure drop and liquid flow rate monitoring system data according to §§ 63.7525 and 63.7535; and<br>b. Reducing the data to 3-hour block averages; and<br>c. Maintaining the 3-hour average pressure drop and liquid flow-rate at or above the operating limits established during the performance test according to § 63.7530(c). |
| 4. Wet Scrubber pH | a. Collecting the pH monitoring system data according to §§ 63.7525 and 63.7535; and<br>b. Reducing the data to 3-hour block averages; and<br>c. Maintaining the 3-hour average pH at or above the operating limit established during the performance test according to § 63.7530(c). |
| 5. Dry Scrubber Sorbent or Carbon Injection Rate | a. Collecting the sorbent or carbon injection rate monitoring system data for the dry scrubber according to §§ 63.7525 and 63.7535; and<br>b. Reducing the data to 3-hour block averages; and<br>c. Maintaining the 3-hour average sorbent or carbon injection rate at or above the operating limit established during the performance test according to §§ 63.7530(c). |
| 6. Electrostatic Precipitator Secondary Current and Voltage or Total Power Input. | a. Collecting the secondary current and voltage or total power input monitoring system data for the electrostatic precipitator according to §§ 63.7525 and 63.7535; and<br>b. Reducing the data to 3-hour block averages; and |

### TABLE 8 TO SUBPART DDDDD OF PART 63.—DEMONSTRATING CONTINUOUS COMPLIANCE—Continued

As stated in § 63.7540, you must show continuous compliance with the emission limitations for affected sources according to the following:

| If you must meet the following operating limits or work practice standards . . . | You must demonstrate continuous compliance by . . . |
|---|---|
| | c. Maintaining the 3-hour average secondary current and voltage or total power input at or above the operating limits established during the performance test according to §§ 63.7530(c). |
| 7. Fuel Pollutant Content | a. Only burning the fuel types and fuel mixtures used to demonstrate compliance with the applicable emission limit according to § 63.7530(c) or (d) as applicable; and<br>b. Keeping monthly records of fuel use according to § 63.7540(a). |

### TABLE 9 TO SUBPART DDDDD OF PART 63.—REPORTING REQUIREMENTS

As stated in § 63.7550, you must comply with the following requirements for reports:

| You must submit a(n) | The report must contain . . . | You must submit the report . . . |
|---|---|---|
| 1. Compliance report | a. Information required in § 63.7550(c)(1) through (11); and<br>b. If there are no deviations from any emission limitation (emission limit and operating limit) that applies to you and there are no deviations from the requirements for work practice standards in Table 8 to this subpart that apply to you, a statement that there were no deviations from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of-control as specified in § 63.8(c)(7), a statement that there were no periods during which the CMSs were out-of-control during the reporting period; and<br>c. If you have a deviation from any emission limitation (emission limit and operating limit) or work practice standard during the reporting period, the report must contain the information in § 63.7550(d). If there were periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of-control, as specified in § 63.8(c)(7), the report must contain the information in § 63.7550(e); and<br>d. If you had a startup, shutdown, or malfunction during the reporting period and you took actions consistent with your startup, shutdown, and malfunction plan, the compliance report must include the information in § 63.10(d)(5)(i) | Semiannually according to the requirements in § 63.7550(b). |
| 2. An immediate startup, shutdown, and malfunction report if you had a startup, shutdown, or malfunction during the reporting period that is not consistent with your startup, shutdown, and malfunction plan, and the source exceeds any applicable emission limitation in the relevant emission standard. | a. Actions taken for the event; and | i. By fax or telephone within 2 working days after starting actions inconsistent with the plan; and |
| | b. The information in § 63.10(d)(5)(ii) | ii. By letter within 7 working days after the end of the event unless you have made alternative arrangements with the permitting authority. |

### TABLE 10 TO SUBPART DDDDD OF PART 63.—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART DDDDD

As stated in § 63.7565, you must comply with the applicable General Provisions according to the following:

| Citation | Subject | Brief description | Applicable |
|---|---|---|---|
| § 63.1 | Applicability | Initial Applicability Determination; Applicability After Standard Established; Permit Requirements; Extensions, Notifications. | Yes. |
| § 63.2 | Definitions | Definitions for part 63 standards | Yes. |
| § 63.3 | Units and Abbreviations | Units and abbreviations for part 63 standards. | Yes. |
| § 63.4 | Prohibited Activities | Prohibited Activities; Compliance date; Circumvention, Severability. | Yes. |
| § 63.5 | Construction/Reconstruction | Applicability; applications; approvals | Yes. |
| § 63.6(a) | Applicability | GP apply unless compliance extension; and GP apply to area sources that become major. | Yes. |
| § 63.6(b)(1)–(4) | Compliance Dates for New and Reconstructed sources. | Standards apply at effective date; 3 years after effective date; upon startup; 10 years after construction or reconstruction commences for 112(f). | Yes. |
| § 63.6(b)(5) | Notification | Must notify if commenced construction or reconstruction after proposal. | Yes. |
| § 63.6(b)(6) | [Reserved]. | | |
| § 63.6(b)(7) | Compliance Dates for New and Reconstructed Area Sources That Become Major. | Area sources that become major must comply with major source standards immediately upon becoming major, regardless of whether required to comply when they were an area source. | Yes. |
| § 63.6(c)(1)–(2) | Compliance Dates for Existing Sources | Comply according to date in subpart, which must be no later than 3 years after effective date; and for 112(f) standards, comply within 90 days of effective date unless compliance extension. | Yes. |
| § 63.6(c)(3)–(4) | [Reserved]. | | |
| § 63.6(c)(5) | Compliance Dates for Existing Area Sources That Become Major. | Area sources that become major must comply with major source standards by date indicated in subpart or by equivalent time period (for example, 3 years). | Yes. |
| § 63.6(d) | [Reserved]. | | |
| § 63.6(e)(1)–(2) | Operation & Maintenance | Operate to minimize emissions at all times; and Correct malfunctions as soon as practicable; and Operation and maintenance requirements independently enforceable; information Administrator will use to determine if operation and maintenance requirements were met. | Yes. |
| § 63.6(e)(3) | Startup, Shutdown, and Malfunction Plan (SSMP). | Requirement for SSM and startup, shutdown, malfunction plan; and content of SSMP. | Yes. |
| § 63.6(f)(1) | Compliance Except During SSM | Comply with emission standards at all times except during SSM. | Yes. |
| § 63.6(f)(2)–(3) | Methods for Determining Compliance | Compliance based on performance test, operation and maintenance plans, records, inspection. | Yes. |
| § 63.6(g)(1)–(3) | Alternative Standard | Procedures for getting an alternative standard. | Yes. |
| § 63.6(h)(1) | Compliance with Opacity/VE Standards | Comply with opacity/VE emission limitations at all times except during SSM. | Yes. |
| § 63.6(h)(2)(i) | Determining Compliance with Opacity/Visible Emission (VE) Standards. | If standard does not state test method, use Method 9 for opacity and Method 22 for VE. | No. |
| § 63.6(h)(2)(ii) | [Reserved]. | | |
| § 63.6(h)(2)(iii) | Using Previous Tests to Demonstrate Compliance with Opacity/VE Standards | Criteria for when previous opacity/VE testing can be used to show compliance with this subpart. | Yes. |
| § 63.6(h)(3) | [Reserved]. | | |
| § 63.6(h)(4) | Notification of Opacity/VE Observation Date. | Notify Administrator of anticipated date of observation. | No. |
| § 63.6(h)(5)(i),(iii)–(v) | Conducting Opacity/VE Observations | Dates and Schedule for conducting opacity/VE observations. | No. |

### TABLE 10 TO SUBPART DDDDD OF PART 63.—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART DDDDD—Continued

As stated in § 63.7565, you must comply with the applicable General Provisions according to the following:

| Citation | Subject | Brief description | Applicable |
|---|---|---|---|
| § 63.6(h)(5)(ii) | Opacity Test Duration and Averaging Times. | Must have at least 3 hours of observation with thirty, 6-minute averages. | No. |
| § 63.6(h)(6) | Records of Conditions During Opacity/VE observations. | Keep records available and allow Administrator to inspect. | No. |
| § 63.6(h)(7)(i) | Report continuous opacity monitoring system Monitoring Data from Performance Test. | Submit continuous opacity monitoring system data with other performance test data. | Yes. |
| § 63.6(h)(7)(ii) | Using continuous opacity monitoring system instead of Method 9. | Can submit continuous opacity monitoring system data instead of Method 9 results even if subpart requires Method 9, but must notify Administrator before performance test. | No. |
| § 63.6(h)(7)(iii) | Averaging time for continuous opacity monitoring system during performance test. | To determine compliance, must reduce continuous opacity monitoring system data to 6-minute averages. | Yes. |
| § 63.6(h)(7)(iv) | Continuous opacity monitoring system requirements. | Demonstrate that continuous opacity monitoring system performance evaluations are conducted according to §§ 63.8(e), continuous opacity monitoring systems are properly maintained and operated according to § 63.8(c) and data quality as § 63.8(d). | Yes. |
| § 63.6(h)(7)(v) | Determining Compliance with Opacity/VE Standards. | Continuous opacity monitoring system is probative but not conclusive evidence of compliance with opacity standard, even if Method 9 observation shows otherwise. Requirements for continuous opacity monitoring system to be probative evidence-proper maintenance, meeting PS 1, and data have not been altered. | Yes. |
| § 63.6(h)(8) | Determining Compliance with Opacity/VE Standards. | Administrator will use all continuous opacity monitoring system, Method 9, and Method 22 results, as well as information about operation and maintenance to determine compliance. | Yes. |
| § 63.6(h)(9) | Adjusted Opacity Standard | Procedures for Administrator to adjust an opacity standard. | Yes. |
| § 63.6(i)(1)–(14) | Compliance Extension | Procedures and criteria for Administrator to grant compliance extension. | Yes. |
| § 63.6(j) | Presidential Compliance Exemption | President may exempt source category from requirement to comply with rule. | Yes. |
| § 63.7(a)(1) | Performance Test Dates | Dates for Conducting Initial Performance Testing and Other Compliance Demonstrations. | Yes. |
| § 63.7(a)(2) | Performance Test Dates | New source with initial startup date before effective date has 180 days after effective date to demonstrate compliance | Yes. |
| § 63.7(a)(2)(ii–viii) | [Reserved]. | | |
| § 63.7(a)(2)(ix) | Performance Test Dates | 1. New source that commenced construction between proposal and promulgation dates, when promulgated standard is more stringent than proposed standard, has 180 days after effective date or 180 days after startup of source, whichever is later, to demonstrate compliance; and. | Yes. |
| | | 2. If source initially demonstrates compliance with less stringent proposed standard, it has 3 years and 180 days after the effective date of the standard or 180 days after startup of source, whichever is later, to demonstrate compliance with promulgated standard. | No. |
| § 63.7(a)(3) | Section 114 Authority | Administrator may require a performance test under CAA Section 114 at any time. | Yes. |

### TABLE 10 TO SUBPART DDDDD OF PART 63.—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART DDDDD—Continued

As stated in § 63.7565, you must comply with the applicable General Provisions according to the following:

| Citation | Subject | Brief description | Applicable |
|---|---|---|---|
| § 63.7(b)(1) | Notification of Performance Test | Must notify Administrator 60 days before the test. | No. |
| § 63.7(b)(2) | Notification of Rescheduling | If rescheduling a performance test is necessary, must notify Administrator 5 days before scheduled date of rescheduled date. | Yes. |
| § 63.7(c) | Quality Assurance/Test Plan | Requirement to submit site-specific test plan 60 days before the test or on date Administrator agrees with: test plan approval procedures; and performance audit requirements; and internal and external QA procedures for testing. | Yes. |
| § 63.7(d) | Testing Facilities | Requirements for testing facilities | Yes. |
| § 63.7(e)(1) | Conditions for Conducting Performance Tests. | 1. Performance tests must be conducted under representative conditions; and | No. |
| | | 2. Cannot conduct performance tests during SSM; and | Yes. |
| | | 3. Not a deviation to exceed standard during SSM; and | Yes. |
| | | 4. Upon request of Administrator, make available records necessary to determine conditions of performance tests. | Yes. |
| § 63.7(e)(2) | Conditions for Conducting Performance Tests. | Must conduct according to rule and EPA test methods unless Administrator approves alternative. | Yes. |
| § 63.7(e)(3) | Test Run Duration | Must have three separate test runs; and Compliance is based on arithmetic mean of three runs; and conditions when data from an additional test run can be used. | Yes. |
| § 63.7(e)(4) | Interaction with other sections of the Act | Nothing in § 63.7(e)(1) through (4) can abrogate the Administrator's authority to require testing under Section 114 of the Act. | Yes. |
| § 63.7(f) | Alternative Test Method | Procedures by which Administrator can grant approval to use an alternative test method. | Yes. |
| § 63.7(g) | Performance Test Data Analysis | Must include raw data in performance test report; and must submit performance test data 60 days after end of test with the Notification of Compliance Status; and keep data for 5 years. | Yes. |
| § 63.7(h) | Waiver of Tests | Procedures for Administrator to waive performance test. | Yes. |
| § 63.8(a)(1) | Applicability of Monitoring Requirements | Subject to all monitoring requirements in standard. | Yes. |
| § 63.8(a)(2) | Performance Specifications | Performance Specifications in appendix B of part 60 apply. | Yes. |
| § 63.8(a)(3) | [Reserved]. | | |
| § 63.8(a)(4) | Monitoring with Flares | Unless your rule says otherwise, the requirements for flares in § 63.11 apply. | No. |
| §63.8(b)(1)(i)–(ii) | Monitoring | Must conduct monitoring according to standard unless Administrator approves alternative. | Yes. |
| § 63.8(b)(1)(iii) | Monitoring | Flares not subject to this section unless otherwise specified in relevant standard. | No. |
| § 63.8(b)(2)–(3) | Multiple Effluents and Multiple Monitoring Systems. | Specific requirements for installing monitoring systems; and must install on each effluent before it is combined and before it is released to the atmosphere unless Administrator approves otherwise; and if more than one monitoring system on an emission point, must report all monitoring system results, unless one monitoring system is a backup. | Yes. |
| § 63.8(c)(1) | Monitoring System Operation and Maintenance. | Maintain monitoring system in a manner consistent with good air pollution control practices. | Yes. |

## TABLE 10 TO SUBPART DDDDD OF PART 63.—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART DDDDD—Continued

As stated in § 63.7565, you must comply with the applicable General Provisions according to the following:

| Citation | Subject | Brief description | Applicable |
|---|---|---|---|
| § 63.8(c)(1)(i) | Routine and Predictable SSM | Maintain and operate CMS according to § 63.6(e)(1). | Yes. |
| § 63.8(c)(1)(ii) | SSM not in SSMP | Must keep necessary parts available for routine repairs of CMSs. | Yes. |
| § 63.8(c)(1)(iii) | Compliance with Operation and Maintenance Requirements. | Must develop and implement an SSMP for CMSs. | Yes. |
| § 63.8(c)(2)–(3) | Monitoring System Installation | Must install to get representative emission and parameter measurements; and must verify operational status before or at performance test. | Yes. |
| § 63.8(c)(4) | Continuous Monitoring System (CMS) Requirements. | CMSs must be operating except during breakdown, out-of-control, repair, maintenance, and high-level calibration drifts. | No. |
| § 63.8(c)(4)(i) | Continuous Monitoring System (CMS) Requirements. | Continuous opacity monitoring system must have a minimum of one cycle of sampling and analysis for each successive 10-second period and one cycle of data recording for each successive 6-minute period. | Yes. |
| § 63.8(c)(4)(ii) | Continuous Monitoring System (CMS) Requirements. | Continuous emissions monitoring system must have a minimum of one cycle of operation for each successive 15-minute period. | No. |
| § 63.8(c)(5) | Continuous Opacity Monitoring system (COMS) Requirements. | Must do daily zero and high level calibrations. | Yes. |
| § 63.8(c)(6) | Continuous Monitoring System (CMS) Requirements. | Must do daily zero and high level calibrations. | No. |
| § 63.8(c)(7)–(8) | Continuous Monitoring Systems Requirements. | Out-of-control periods, including reporting | Yes. |
| § 63.8(d) | Continuous Monitoring Systems Quality Control. | Requirements for continuous monitoring systems quality control, including calibration, etc.; and must keep quality control plan on record for the life of the affected source. Keep old versions for 5 years after revisions. | Yes. |
| § 63.8(e) | Continuous monitoring systems Performance Evaluation. | Notification, performance evaluation test plan, reports. | Yes. |
| § 63.8(f)(1)–(5) | Alternative Monitoring Method | Procedures for Administrator to approve alternative monitoring. | Yes. |
| § 63.8(f)(6) | Alternative to Relative Accuracy Test | Procedures for Administrator to approve alternative relative accuracy tests for continuous emissions monitoring system. | No. |
| § 63.8(g)(1)–(4) | Data Reduction | Continuous opacity monitoring system 6-minute averages calculated over at least 36 evenly spaced data points; and continuous emissions monitoring system 1-hour averages computed over at least 4 equally spaced data points. | Yes. |
| § 63.8(g)(5) | Data Reduction | Data that cannot be used in computing averages for continuous emissions monitoring system and continuous opacity monitoring system. | No. |
| § 63.9(a) | Notification Requirements | Applicability and State Delegation | Yes. |
| § 63.9(b)(1)–(5) | Initial Notifications | Submit notification 120 days after effective date; and Notification of intent to construct/reconstruct; and Notification of commencement of construct/reconstruct; Notification of startup; and Contents of each. | Yes. |
| § 63.9(c) | Request for Compliance Extension | Can request if cannot comply by date or if installed BACT/LAER. | Yes. |
| § 63.9(d) | Notification of Special Compliance Requirements for New Source. | For sources that commence construction between proposal and promulgation and want to comply 3 years after effective date. | Yes. |
| § 63.9(e) | Notification of Performance Test | Notify Administrator 60 days prior | No. |

### TABLE 10 TO SUBPART DDDDD OF PART 63.—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART DDDDD—Continued

As stated in § 63.7565, you must comply with the applicable General Provisions according to the following:

| Citation | Subject | Brief description | Applicable |
|---|---|---|---|
| § 63.9(f) | Notification of VE/Opacity Test | Notify Administrator 30 days prior | No. |
| § 63.9(g) | Additional Notifications When Using Continuous Monitoring Systems. | Notification of performance evaluation; and notification using continuous opacity monitoring system data; and notification that exceeded criterion for relative accuracy. | Yes. |
| § 63.9(h)(1)–(6) | Notification of Compliance Status | Contents; and due 60 days after end of performance test or other compliance demonstration, and when to submit to Federal vs. State authority. | Yes. |
| § 63.9(i) | Adjustment of Submittal Deadlines | Procedures for Administrator to approve change in when notifications must be submitted. | Yes. |
| § 63.9(j) | Change in Previous Information | Must submit within 15 days after the change. | Yes. |
| § 63.10(a) | Recordkeeping/Reporting | Applies to all, unless compliance extension; and when to submit to Federal vs. State authority; and procedures for owners of more than 1 source. | Yes. |
| § 63.10(b)(1) | Recordkeeping/Reporting | General Requirements; and keep all records readily available and keep for 5 years. | Yes. |
| § 63.10(b)(2)(i)–(v) | Records related to Startup, Shutdown, and Malfunction. | Occurrence of each of operation (process, equipment); and occurrence of each malfunction of air pollution equipment; and maintenance of air pollution control equipment; and actions during startup, shutdown, and malfunction. | Yes. |
| § 63.10(b)(2)(vi) and (x–xi) | Continuous monitoring systems Records | Malfunctions, inoperative, out-of-control; and calibration checks; and adjustments, maintenance. | Yes. |
| § 63.10(b)(2)(vii)–(ix) | Records | Measurements to demonstrate compliance with emission limitations; and performance test, performance evaluation, and visible emission observation results; and measurements to determine conditions of performance tests and performance evaluations. | Yes. |
| § 63.10(b)(2)(xii) | Records | Records when under waiver | Yes. |
| § 63.10(b)(2)(xiii) | Records | Records when using alternative to relative accuracy test. | No. |
| § 63.10(b)(2)(xiv) | Records | All documentation supporting Initial Notification and Notification of Compliance Status. | Yes. |
| § 63.10(b)(3) | Records | Applicability Determinations | Yes. |
| § 63.10(c)(1),(5)–(8),(10)–(15) | Records | Additional Records for continuous monitoring systems. | Yes. |
| § 63.10(c)(7)–(8) | Records | Records of excess emissions and parameter monitoring exceedances for continuous monitoring systems. | No. |
| § 63.10(d)(1) | General Reporting Requirements | Requirement to report | Yes. |
| § 63.10(d)(2) | Report of Performance Test Results | When to submit to Federal or State authority. | Yes. |
| § 63.10(d)(3) | Reporting Opacity or VE Observations | What to report and when | Yes. |
| § 63.10(d)(4) | Progress Reports | Must submit progress reports on schedule if under compliance extension. | Yes. |
| § 63.10(d)(5) | Startup, Shutdown, and Malfunction Reports. | Contents and submission | Yes. |
| § 63.10(e)(1)(2) | Additional continuous monitoring systems Reports. | Must report results for each CEM on a unit; and written copy of performance evaluation; and 3 copies of continuous opacity monitoring system performance evaluation. | Yes. |
| § 63.10(e)(3) | Reports | Excess Emission Reports | No. |
| § 63.10(e)(3)(i–iii) | Reports | Schedule for reporting excess emissions and parameter monitor exceedance (now defined as deviations). | No. |

TABLE 10 TO SUBPART DDDDD OF PART 63.—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART DDDDD—Continued

As stated in § 63.7565, you must comply with the applicable General Provisions according to the following:

| Citation | Subject | Brief description | Applicable |
|---|---|---|---|
| § 63.10(e)(3)(iv–v) | Excess Emissions Reports | Requirement to revert to quarterly submission if there is an excess emissions and parameter monitor exceedance (now defined as deviations); and provision to request semiannual reporting after compliance for one year; and submit report by 30th day following end of quarter or calendar half; and if there has not been an exceedance or excess emission (now defined as deviations), report contents is a statement that there have been no deviations. | No. |
| § 63.10(e)(3)(iv–v) | Excess Emissions Reports | Must submit report containing all of the information in § 63.10(c)(5–13), § 63.8(c)(7–8). | No. |
| § 63.10(e)(3)(vi–viii) | Excess Emissions Report and Summary Report. | Requirements for reporting excess emissions for continuous monitoring systems (now called deviations); Requires all of the information in § 63.10(c)(5–13), § 63.8(c)(7–8). | No. |
| § 63.10(e)(4) | Reporting continuous opacity monitoring system data. | Must submit continuous opacity monitoring system data with performance test data. | Yes. |
| § 63.10(f) | Waiver for Recordkeeping/Reporting | Procedures for Administrator to waive | Yes. |
| § 63.11 | Flares | Requirements for flares | No. |
| § 63.12 | Delegation | State authority to enforce standards | Yes. |
| § 63.13 | Addresses | Addresses where reports, notifications, and requests are sent. | Yes. |
| § 63.14 | Incorporation by Reference | Test methods incorporated by reference | Yes. |
| § 63.15 | Availability of Information | Public and confidential Information | Yes. |

## Appendix A to Subpart DDDDD—Methodology and Criteria for Demonstrating Eligibility for the Health-Based Compliance Alternatives Specified for the Large Solid Fuel Subcategory

### 1. Purpose/Introduction

This appendix provides the methodology and criteria for demonstrating that your affected source is eligible for the compliance alternative for the HCl emission limit and/or the total selected metals (TSM) emission limit. This appendix specifies emissions testing methods that you must use to determine HCl, chlorine, and manganese emissions from the affected units and what parts of the affected source facility must be included in the eligibility demonstration. You must demonstrate that your affected source is eligible for the health-based compliance alternatives using either a look-up table analysis (based on the look-up tables included in this appendix) or a site-specific compliance demonstration performed according to the criteria specified in this appendix. This appendix also specifies how and when you file any eligibility demonstrations for your affected source and how to show that your affected source remains eligible for the health-based compliance alternatives in the future.

### 2. Who Is Eligible To Demonstrate That They Qualify for the Health-Based Compliance Alternatives?

Each new, reconstructed, or existing affected source may demonstrate that they are eligible for the health-based compliance alternatives. Section 63.7490 of subpart DDDDD defines the affected source and explains which affected sources are new, existing, or reconstructed.

### 3. What Parts of My Facility Have To Be Included in the Health-Based Eligibility Demonstration?

If you are attempting to determine your eligibility for the compliance alternative for HCl, you must include every emission point subject to subpart DDDDD that emits either HCl or $Cl_2$ in the eligibility demonstration.

If you are attempting to determine your eligibility for the compliance alternative for TSM, you must include every emission point subject to subpart DDDDD that emits manganese in the eligibility demonstration.

### 4. How Do I Determine HAP Emissions From My Affected Source?

(a) You must conduct HAP emissions tests or fuel analysis for every emission point covered under subpart DDDDD within the affected source facility according to the requirements in paragraphs (b) through (f) of this section and the methods specified in Table 1 of this appendix.

(1) If you are attempting to determine your eligibility for the compliance alternative for HCl, you must test the subpart DDDDD units at your facility for both HCl and $Cl_2$. When conducting fuel analysis, you must assume any chlorine detected will be emitted as $Cl_2$.

(2) If you are attempting to determine your eligibility for the compliance alternative for TSM, you must test the subpart DDDDD units at your facility for manganese.

(b) *Periods when emissions tests must be conducted.*

(1) You must not conduct emissions tests during periods of startup, shutdown, or malfunction, as specified in § 63.7(e)(1).

(2) You must test under worst-case operating conditions as defined in this appendix. You must describe your worst-case operating conditions in your performance test report for the process and control systems (if applicable) and explain why the conditions are worst-case.

(c) *Number of test runs.* You must conduct three separate test runs for each test required in this section, as specified in § 63.7(e)(3). Each test run must last at least 1 hour.

(d) *Sampling locations.* Sampling sites must be located at the outlet of the control device and prior to any releases to the atmosphere.

(e) *Collection of monitoring data for HAP control devices.* During the emissions test, you must collect operating parameter monitoring system data at least every 15 minutes during the entire emissions test and establish the site-specific operating requirements in Tables 3 or 4, as appropriate, of subpart DDDDD using data from the monitoring system and the procedures specified in § 63.7530 of subpart DDDDD.

(f) *Nondetect data.* You may treat emissions of an individual HAP as zero if all of the test runs result in a nondetect measurement and the condition in paragraph (f)(1) of this section is met for the manganese test method. Otherwise, nondetect data for individual HAP must be treated as one-half of the method detection limit.

(1) For manganese measured using Method 29 in appendix A to 40 CFR part 60, you analyze samples using atomic absorption spectroscopy (AAS).

(g) You must determine the maximum hourly emission rate for each appropriate emission point according to Equation 1 of this appendix.

$$\text{Max Hourly Emissions} = \sum_{i=1}^{n} \left(\text{Er} \times \text{Hm}\right) \qquad \text{(Eq. 1)}$$

Where:

Max Hourly Emissions = Maximum hourly emissions for hydrogen chloride, chlorine, or manganese, in units of pounds per hour.

Er = Emission rate (the 3-run average as determined according to Table 1 of this appendix or the pollutant concentration in the fuel samples analyzed according to § 63.7521) for hydrogen chloride, chlorine, or manganese, in units of pounds per million Btu of heat input.

Hm = Maximum rated heat input capacity of appropriate emission point, in units of million Btu per hour.

**5. What Are the Criteria for Determining If My Facility Is Eligible for the Health-Based Compliance Alternatives?**

(a) Determine the HAP emissions from each appropriate emission point within the affected source facility using the procedures specified in section 4 of this appendix.

(b) Demonstrate that your facility is eligible for either of the health-based compliance alternatives using either the methods described in section 6 of this appendix (look-up table analysis) or section 7 of this appendix (site-specific compliance demonstration).

(c) Your facility is eligible for the health-based compliance alternative for HCl if one of the following two statements is true:

(1) The calculated HCl-equivalent emission rate is below the appropriate value in the look-up table;

(2) Your site-specific compliance demonstration indicates that your maximum HI for HCl and $C1_2$ at a location where people live is less than or equal to 1.0;

(d) Your facility is eligible for the health-based compliance alternative for TSM if one of the following two statements is true:

(1) The manganese emission rate for all your subpart DDDDD sources is below the appropriate value in the look-up table;

(2) Your site-specific compliance demonstration indicates that your maximum HQ for manganese at a location where people live is less than or equal to 1.0.

**6. How Do I Conduct a Look-Up Table Analysis?**

You may use look-up tables to demonstrate that your facility is eligible for either the compliance alternative for the HCl emission limit or the compliance alternative for TSM emission limit.

(a) *HCl health-based compliance alternative.* (1) To calculate the total toxicity-weighted HCl-equivalent emission rate for your facility, first calculate the total affected source emission rate of HCl by summing the maximum hourly HCl emission rates from all your subpart DDDDD sources. Then, similarly, calculate the total affected source emission rate for $Cl_2$. Finally, calculate the toxicity-weighted emission rate (expressed in HCl equivalents) according to Equation 2 of this appendix.

$$ER_{tw} = \sum \left(ER_i \times \left(RfC_{HCl}/RfC_i\right)\right) \qquad \text{(Eq. 2)}$$

Where:

$ER_{tw}$ is the HCl-equivalent emission rate, lb/hr.

$ER_i$ is the emission rate of HAP i in lbs/hr

$RfC_i$ is the reference concentration of HAP i

$RfC_{HCl}$ is the reference concentration of HCl (RfCs for HCl and $Cl_2$ can be found at *http://www.epa.gov/ttn/atw/toxsource/summary.html).*

(2) The calculated HCl-equivalent emission rate will then be compared to the appropriate allowable emission rate in Table 2 of this appendix. To determine the correct value from the table, an average value for the appropriate subpart DDDDD emission points should be used for stack height and the minimum distance between any appropriate subpart DDDDD stack at the facility and the property boundary should be used for property boundary distance. Appropriate emission points and stacks are those that emit HCl and/or $Cl_2$. If one or both of these values does not match the exact values in the lookup tables, then use the next lowest table value. (**Note:** If your average stack height is less than 5 meters, you must use the 5 meter row.) Your facility is eligible to comply with the health-based alternative HCl emission limit if your toxicity-weighted HCl equivalent emission rate, determined using the methods specified in this appendix, does not exceed the appropriate value in Table 2 of this appendix.

(b) *TSM Compliance Alternative.* To calculate the total manganese emission rate for your affected source, sum the maximum hourly manganese emission rates for all your subpart DDDDD sources. The calculated manganese emission rate will then be compared to the allowable emission rate in the Table 3 of this appendix. To determine the correct value from the table, an average value for the appropriate subpart DDDDD emission points should be used for stack height and the minimum distance between any appropriate subpart DDDDD stack at the facility and the property boundary should be used for property boundary distance. Appropriate emission points and stacks are those that emit manganese. If one or both of these values does not match the exact values in the lookup tables, then use the next lowest table value. (**Note:** If your average stack height is less than 5 meters, you must use the 5 meter row.) Your facility may exclude manganese when demonstrating compliance with the TSM emission limit if your manganese emission rate, determined using the methods specified in this appendix, does not exceed the appropriate value specified in Table 3 of this appendix.

**7. How Do I Conduct a Site-Specific Compliance Demonstration?**

If you fail to demonstrate that your facility is able to comply with one or both of the alternative health-based emission standards using the look-up table approach, you may choose to perform a site-specific compliance demonstration for your facility. You may use any scientifically-accepted peer-reviewed risk assessment methodology for your site-specific compliance demonstration. An example of one approach for performing a site-specific compliance demonstration for air toxics can be found in the EPA's ''Air Toxics Risk Assessment Reference Library, Volume 2, Site-Specific Risk Assessment Technical Resource Document'', which may be obtained through the EPA's Air Toxics Web site at *http://www.epa.gov/ttn/fera/risk_atoxic.html.*

(a) Your facility is eligible for the HCl alternative compliance option if your site-specific compliance demonstration shows that the maximum HI for HCl and $Cl_2$ from your subpart DDDDD sources is less than or equal to 1.0.

(b) Your facility is eligible for the TSM alternative compliance option if your site-specific compliance demonstration shows that the maximum HQ for manganese from your subpart DDDDD sources is less than or equal to 1.0.

(c) At a minimum, your site-specific compliance demonstration must:

(1) Estimate long-term inhalation exposures through the estimation of annual

or multi-year average ambient concentrations;

(2) Estimate the inhalation exposure for the individual most exposed to the facility's emissions;

(3) Use site-specific, quality-assured data wherever possible;

(4) Use health-protective default assumptions wherever site-specific data are not available, and;

(5) Contain adequate documentation of the data and methods used for the assessment so that it is transparent and can be reproduced by an experienced risk assessor and emissions measurement expert.

(d) Your site-specific compliance demonstration need not:

(1) Assume any attenuation of exposure concentrations due to the penetration of outdoor pollutants into indoor exposure areas;

(2) Assume any reaction or deposition of the emitted pollutants during transport from the emission point to the point of exposure.

### 8. What Must My Health-Based Eligibility Demonstration Contain?

(a) Your health-based eligibility demonstration must contain, at a minimum, the information specified in paragraphs (a)(1) through (6) of this section.

(1) Identification of each appropriate emission point at the affected source facility, including the maximum rated capacity of each appropriate emission point.

(2) Stack parameters for each appropriate emission point including, but not limited to, the parameters listed in paragraphs (a)(2)(i) through (iv) below:

(i) Emission release type.

(ii) Stack height, stack area, stack gas temperature, and stack gas exit velocity.

(iii) Plot plan showing all emission points, nearby residences, and fenceline.

(iv) Identification of any control devices used to reduce emissions from each appropriate emission point.

(3) Emission test reports for each pollutant and appropriate emission point which has been tested using the test methods specified in Table 1 of this appendix, including a description of the process parameters identified as being worst case. Fuel analyses for each fuel and emission point which has been conducted including collection and analytical methods used.

(4) Identification of the RfC values used in your look-up table analysis or site-specific compliance demonstration.

(5) Calculations used to determine the HCl-equivalent or manganese emission rates according to sections 6(a) or (b) of this appendix.

(6) Identification of the controlling process factors (including, but not limited to, fuel type, heat input rate, type of control devices, process parameters reflecting the emissions rates used for your eligibility demonstration) that will become Federally enforceable permit conditions used to show that your facility remains eligible for the health-based compliance alternatives.

(b) If you use the look-up table analysis in section 6 of this appendix to demonstrate that your facility is eligible for either health-based compliance alternative, your eligibility demonstration must contain, at a minimum, the information in paragraphs (a) and (b)(1) through (3) of this section.

(1) Calculations used to determine the average stack height of the subpart DDDDD emission points that emit either manganese or HCl and $Cl_2$.

(2) Identification of the subpart DDDDD emission point, that emits either manganese or HCl and $Cl_2$, with the minimum distance to the property boundary of the facility.

(3) Comparison of the values in the look-up tables (Tables 2 and 3 of this appendix) to your maximum HCl-equivalent or manganese emission rates.

(c) If you use a site-specific compliance demonstration as described in section 7 of this appendix to demonstrate that your facility is eligible, your eligibility demonstration must contain, at a minimum, the information in paragraphs (a) and (c)(1) through (7) of this section:

(1) Identification of the risk assessment methodology used.

(2) Documentation of the fate and transport model used.

(3) Documentation of the fate and transport model inputs, including the information described in paragraphs (a)(1) through (5) of this section converted to the dimensions required for the model and all of the following that apply: meteorological data; building, land use, and terrain data; receptor locations and population data; and other facility-specific parameters input into the model.

(4) Documentation of the fate and transport model outputs.

(5) Documentation of any exposure assessment and risk characterization calculations.

(6) Comparison of the HQ HI to the limit of 1.0.

### 9. When Do I Have to Complete and Submit My Health-Based Eligibility Demonstration?

(a) If you have an existing affected source, you must complete and submit your eligibility demonstration to your permitting authority, along with a signed certification that the demonstration is an accurate depiction of your facility, no later than the date one year prior to the compliance date of subpart DDDDD. A separate copy of the eligibility demonstration must be submitted to: U.S. EPA, Risk and Exposure Assessment Group, Emission Standards Division (C404–01), Attn: Group Leader, Research Triangle Park, North Carolina 27711, electronic mail address *REAG@epa.gov.*

(b) If you have a new or reconstructed affected source that starts up before the effective date of subpart DDDDD, or an affected source that is an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP before the effective date of subpart DDDDD, then you must comply with the requirements of subpart DDDDD until your eligibility demonstration is completed and submitted to your permitting authority.

(c) If you have a new or reconstructed affected source that starts up after the effective date of subpart DDDDD, or an affected source that is an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP after the effective date for subpart DDDDD, then you must follow the schedule in paragraphs (c)(1) and (2) of this section.

(1) You must complete and submit a preliminary eligibility demonstration based on the information (*e.g.*, equipment types, estimated emission rates, etc.) used to obtain your title V permit. You must base your preliminary eligibility demonstration on the maximum emissions allowed under your title V permit. If the preliminary eligibility demonstration indicates that your affected source facility is eligible for either compliance alternative, then you may start up your new affected source and your new affected source will be considered in compliance with the alternative HCl standard and subject to the compliance requirements in this appendix or, in the case of manganese, your compliance demonstration with the TSM emission limit is based on 7 metals (excluding manganese).

(2) You must conduct the emission tests or fuel analysis specified in section 4 of this appendix upon initial startup and use the results of these emissions tests to complete and submit your eligibility demonstration within 180 days following your initial startup date. To be eligible, you must meet the criteria in section 11 of this appendix within 18 months following initial startup of your affected source.

### 10. When Do I Become Eligible for the Health-Based Compliance Alternatives?

To be eligible for either health-based compliance alternative, the parameters that defined your affected source as eligible for the health-based compliance alternatives (including, but not limited to, fuel type, fuel mix (annual average), type of control devices, process parameters reflecting the emissions rates used for your eligibility demonstration) must be submitted for incorporation as Federally enforceable limits into your title V permit. If you do not meet these criteria, then your affected source is subject to the applicable emission limits, operating limits, and work practice standards in Subpart DDDDD.

### 11. How Do I Ensure That My Facility Remains Eligible for the Health-Based Compliance Alternatives?

(a) You must update your eligibility demonstration and resubmit it each time you have a process change, such that any of the parameters that defined your affected source changes in a way that could result in increased HAP emissions (including, but not limited to, fuel type, fuel mix (annual average), change in type of control device, changes in process parameters documented as worst-case conditions during the emissions testing used for your approved eligibility demonstration).

(b) If you are updating your eligibility demonstration to account for an action in paragraph (a) of this section, then you must perform emission testing or fuel analysis according to section 4 of this appendix for the subpart DDDDD emission points that may have increased HAP emissions beyond the levels reflected in your previously approved eligibility demonstration due to the process change. You must submit your revised eligibility demonstration to the permitting authority prior to revising your permit to incorporate the process change. If your updated eligibility demonstration indicates that your affected source is no longer eligible for the health-based compliance alternatives, then you must comply with the applicable emission limits, operating limits, and compliance requirements in Subpart DDDDD prior to making the process change and revising your permit.

### 12. What Records Must I Keep?

You must keep records of the information used in developing the eligibility demonstration for your affected source, including all of the information specified in section 8 of this appendix.

### 13. Definitions

The definitions in § 63.7575 of subpart DDDDD apply to this appendix. Additional definitions applicable for this appendix are as follows:

*Hazard Index (HI)* means the sum of more than one hazard quotient for multiple substances and/or multiple exposure pathways.

*Hazard Quotient (HQ)* means the ratio of the predicted media concentration of a pollutant to the media concentration at which no adverse effects are expected. For inhalation exposures, the HQ is calculated as the air concentration divided by the RfC.

*Look-up table analysis* means a risk screening analysis based on comparing the HAP or HAP-equivalent emission rate from the affected source to the appropriate maximum allowable HAP or HAP-equivalent emission rates specified in Tables 2 and 3 of this appendix.

*Reference Concentration (RfC)* means an estimate (with uncertainty spanning perhaps an order of magnitude) of a continuous inhalation exposure to the human population (including sensitive subgroups) that is likely to be without an appreciable risk of deleterious effects during a lifetime. It can be derived from various types of human or animal data, with uncertainty factors generally applied to reflect limitations of the data used.

*Worst-case operating conditions* means operation of an affected unit during emissions testing under the conditions that result in the highest HAP emissions or that result in the emissions stream composition (including HAP and non-HAP) that is most challenging for the control device if a control device is used. For example, worst-case conditions could include operation of an affected unit firing solid fuel likely to produce the most HAP.

TABLE 1 TO APPENDIX B OF SUBPART DDDDD—EMISSION TEST METHODS

| For . . . | You must . . . | Using . . . |
|---|---|---|
| (1) Each subpart DDDDD emission point for which you choose to use a compliance alternative. | Select sampling ports' location and the number of traverse points. | Method 1 of 40 CFR part 60, appendix A. |
| (2) Each subpart DDDDD emission point for which you choose to use a compliance alternative. | Determine velocity and volumetric flow rate; ... | Method 2, 2F, or 2G in appendix A to 40 CFR part 60. |
| (3) Each subpart DDDDD emission point for which you choose to use a compliance alternative. | Conduct gas molecular weight analysis .......... | Method 3A or 3B in appendix A to 40 CFR part 60. |
| (4) Each subpart DDDDD emission point for which you choose to use a compliance alternative. | Measure moisture content of the stack gas .... | Method 4 in appendix A to 40 CFR part 60. |
| (5) Each subpart DDDDD emission point for which you choose to use the HCl compliance alternative. | Measure the hydrogen chloride and chlorine emission concentrations. | Method 26 or 26A in appendix A to 40 CFR part 60. |
| (6) Each subpart DDDDD emission point for which you choose to use the TSM compliance alternative. | Measure the manganese emission concentration. | Method 29 in appendix A to 40 CFR part 60. |
| (7) Each subpart DDDDD emission point for which you choose to use a compliance alternative. | Convert emissions concentration to lb per MMBtu emission rates. | Method 19 F-factor methodology in appendix A to part 60 of this chapter. |

TABLE 2 TO APPENDIX A OF SUBPART DDDDD—ALLOWABLE TOXICITY-WEIGHTED EMISSION RATE EXPRESSED IN HCl EQUIVALENTS (lbs/hr)

| Stack ht. (m) | Distance to property boundary (m) | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 0 | 50 | 100 | 150 | 200 | 250 | 500 | 1000 | 1500 | 2000 | 3000 | 5000 |
| 5 | 114.9 | 114.9 | 114.9 | 114.9 | 114.9 | 114.9 | 144.3 | 287.3 | 373.0 | 373.0 | 373.0 | 373.0 |
| 10 | 188.5 | 188.5 | 188.5 | 188.5 | 188.5 | 188.5 | 195.3 | 328.0 | 432.5 | 432.5 | 432.5 | 432.5 |
| 20 | 386.1 | 386.1 | 386.1 | 386.1 | 386.1 | 386.1 | 386.1 | 425.4 | 580.0 | 602.7 | 602.7 | 602.7 |
| 30 | 396.1 | 396.1 | 396.1 | 396.1 | 396.1 | 396.1 | 396.1 | 436.3 | 596.2 | 690.6 | 807.8 | 816.5 |
| 40 | 408.1 | 408.1 | 408.1 | 408.1 | 408.1 | 408.1 | 408.1 | 448.2 | 613.3 | 715.5 | 832.2 | 966.0 |
| 50 | 421.4 | 421.4 | 421.4 | 421.4 | 421.4 | 421.4 | 421.4 | 460.6 | 631.0 | 746.3 | 858.2 | 1002.8 |
| 60 | 435.5 | 435.5 | 435.5 | 435.5 | 435.5 | 435.5 | 435.5 | 473.4 | 649.0 | 778.6 | 885.0 | 1043.4 |
| 70 | 450.2 | 450.2 | 450.2 | 450.2 | 450.2 | 450.2 | 450.2 | 486.6 | 667.4 | 813.8 | 912.4 | 1087.4 |
| 80 | 465.5 | 465.5 | 465.5 | 465.5 | 465.5 | 465.5 | 465.5 | 500.0 | 685.9 | 849.8 | 940.9 | 1134.8 |
| 100 | 497.5 | 497.5 | 497.5 | 497.5 | 497.5 | 497.5 | 497.5 | 527.4 | 723.6 | 917.1 | 1001.2 | 1241.3 |
| 200 | 677.3 | 677.3 | 677.3 | 677.3 | 677.3 | 677.3 | 677.3 | 682.3 | 919.8 | 1167.1 | 1390.4 | 1924.6 |

TABLE 3 TO APPENDIX A OF SUBPART DDDDD—ALLOWABLE MANGANESE EMISSION RATE (lbs/hr)

| Stack ht. (m) | Distance to property boundary (m) | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 0 | 50 | 100 | 150 | 200 | 250 | 500 | 1000 | 1500 | 2000 | 3000 | 5000 |
| 5 | 0.29 | 0.29 | 0.29 | 0.29 | 0.29 | 0.29 | 0.36 | 0.72 | 0.93 | 0.93 | 0.93 | 0.94 |
| 10 | 0.47 | 0.47 | 0.47 | 0.47 | 0.47 | 0.47 | 0.49 | 0.82 | 1.08 | 1.08 | 1.08 | 1.08 |
| 20 | 0.97 | 0.97 | 0.97 | 0.97 | 0.97 | 0.97 | 0.97 | 1.06 | 1.45 | 1.51 | 1.51 | 1.51 |
| 30 | 0.99 | 0.99 | 0.99 | 0.99 | 0.99 | 0.99 | 0.99 | 1.09 | 1.49 | 1.72 | 2.02 | 2.04 |
| 40 | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 | 1.12 | 1.53 | 1.79 | 2.08 | 2.42 |
| 50 | 1.05 | 1.05 | 1.05 | 1.05 | 1.05 | 1.05 | 1.05 | 1.15 | 1.58 | 1.87 | 2.15 | 2.51 |
| 60 | 1.09 | 1.09 | 1.09 | 1.09 | 1.09 | 1.09 | 1.09 | 1.18 | 1.62 | 1.95 | 2.21 | 2.61 |
| 70 | 1.13 | 1.13 | 1.13 | 1.13 | 1.13 | 1.13 | 1.13 | 1.22 | 1.67 | 2.03 | 2.28 | 2.72 |
| 80 | 1.16 | 1.16 | 1.16 | 1.16 | 1.16 | 1.16 | 1.16 | 1.25 | 1.71 | 2.12 | 2.35 | 2.84 |
| 100 | 1.24 | 1.24 | 1.24 | 1.24 | 1.24 | 1.24 | 1.24 | 1.32 | 1.81 | 2.29 | 2.50 | 3.10 |
| 200 | 1.69 | 1.69 | 1.69 | 1.69 | 1.69 | 1.69 | 1.69 | 1.71 | 2.30 | 2.92 | 3.48 | 4.81 |

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