CONSTRUCTION AND OPERATING PERMIT APPLICATION
PYRAMAX CERAMICS ▪ PROPPANT PLANT

WRENS, GEORGIA

Prepared by:

PYRAMAX CERAMICS, LLC

TRINITY CONSULTANTS
325 Arlington Ave.
Suite 500
Charlotte, NC 28203
(704) 553-7747

Tom Muscenti ▪ Managing Consultant
Justin Fickas ▪ Managing Consultant

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1. INTRODUCTION

PyraMax Ceramics, LLC (PyraMax) is proposing to construct a greenfield ceramic proppant manufacturing facility near Wrens, Jefferson County, Georgia. The Proppant Plant will produce proppant beads for use in the oil and natural gas industry. The proposed greenfield proppant manufacturing facility will be a major source under the Federal Prevention of Significant Deterioration (PSD) program. This application includes PSD review for nitrogen oxides (NO_X), carbon monoxide (CO), particulate matter less than 10 microns in diameter (PM_{10}), particulate matter less than 2.5 microns in diameter ($PM_{2.5}$), greenhouse gases (GHGs), Volatile Organic Compounds (VOC), and sulfur dioxide (SO_2).

PyraMax requests that a state permit authorizing the construction and operation of the proposed proppant plant be issued under the provisions of the Georgia Environmental Protection Division (EPD) Rules for Air Quality Control, Chapter 391-3-1.

1.1 FACILITY DESCRIPTION

The facility will be located in Jefferson County off of Kings Mill Road (Co. Road 291) South of the town of Wrens, Georgia. The approximate UTM coordinates of the facility are 372.48 kilometers east and 3670.75 kilometers north (UTM Zone 17). An area map and plot plan of the site are included in Appendix A, which show emission source locations, buildings, nearby roadways, and surrounding property. Jefferson county is designated as “attainment” or “unclassifiable” for all criteria pollutants with respect to the National Ambient Air Quality Standards (NAAQS). Therefore, nonattainment new source review (NNSR) does not apply to this proposed facility, and PSD applicability must be evaluated for all criteria pollutants.

PyraMax plans to construct a greenfield proppant facility for the production of proppant beads for use in the oil and gas industry. The major raw material is clay. The clay is mixed with chemicals and then fired in a kiln process to produce ceramic beads. Expected emissions from the facility are NO_X, CO, PM, PM_{10}, $PM_{2.5}$, SO_2, VOC, GHG and combustion emissions associated with natural gas and propane combustion. Additionally, hydrogen fluoride (HF), hydrogen chloride (HCl), and methanol will be emitted from the process either due to the presence in the raw material (HF and HCl) or as an impurity in the chemicals added (methanol).

The proposed plant will be a major source with respect to the Title V (Part 70) Operating Permit Program as administered by the Georgia EPD pursuant to Chapter 391-3-1-.03(10) of the Georgia Rules for Air Quality Control. The proppant plant is a major source due to potential emissions of criteria pollutants and hazardous air pollutants (HAPs) in excess of the major source thresholds (100 tpy for criteria pollutants, 10 tpy for individual HAP, 25 tpy for combined HAP). PyraMax will submit a Title V permit application within 12-months of commencement of operation.

1.2 APPLICATION CONTENTS

This permit application is organized as follows:

- Section 2 contains a detailed description of the facility processes;
- Section 3 contains emissions calculations methodology and results;
- Section 4 contains a regulatory applicability analysis;
- Section 5 contains the BACT applicability;
- Section 6 contains the Case-by-Case MACT Analysis;
- Appendix A contains an area map and plot plan;
- Appendix B contains general process flow diagrams;
- Appendix C contains detailed emissions calculations;
- Appendix D contains the BACT supporting information;
- Appendix E contains the Case-by-Case MACT supporting information; and
- Appendix F contains the permit application forms

2.1 OVERALL PROCESS DESCRIPTION

Proppant agents are used in the oil and gas industries to improve the productivity of an oil or gas well. Proppants improve the well's flow capacity and increasing recovery rates. The proposed PyraMax proppant plant will consist of the following areas:

- raw material handling;
- feedstock preparation;
- pelletization;
- green pellet screening;
- calcinations/sintering; and
- finishing

The ceramic proppant material produced by the facility will effectively be an "inert" material. Detailed process flow diagrams of the production operations are included in Appendix B of this application. The following sections discuss the process in further detail.

2.2 RAW MATERIAL HANDLING

The feedstock for the plant will be locally mined raw clay. The facility will receive clay via trucks to any of twelve (12) covered bays. Expected emissions from the raw material handling operations are PM, PM_{10} and $PM_{2.5}$. However, due to the high moisture content of the clay (approximately 20 percent by weight [wt%]), emissions from raw material handing are negligible.

2.3 FEEDSTOCK PREPARATION

The raw feedstock materials are moved from the storage bays to the shredder by a front-end loader. The shredder breaks up the clay into a fine powder. The shredder product is then moved to the feeder via a partially covered conveyor. Following the shredder, the material is moved by conveyor to a feeder which transfers the material into a round tank with a mixer. The purpose of the mix tank is for the conversion of feedstock clay into a stable suspended mixture by mixing clay with water and a small amount of dispersant. The material is agitated and then pH balanced using aqueous ammonia. The mixture is then stored in open top storage tanks under constant agitation to keep the mixture suspended. Some screening of the wet material with a wet screen is then completed prior to addition of the binder material. This additive material is stored in a silo shared by two lines. The additive is mixed with water and heated prior to addition to the raw material mixture.

Expected emissions from feedstock preparation include VOC (impurity in the additive), PM, PM_{10}, $PM_{2.5}$. Similar to the raw material handling operations, particulate emissions will be negligible due to the high moisture content and wet material.

2.4 PELLETIZATION

Pelletization occurs in the pelletization process. As coated green pellets dry, additional layers are added until the desired bead size is achieved.

The pelletizer is heated by a direct fired natural gas (with propane backup) air heater in which the entire volume of drying air is heated to the desired temperature by means of combustion gases from the gas burner. The total heat capacity of the combustion units used will be 75 MM Btu/hr, and combustion units will be equipped with Low NO_X burners.

Spent drying air is exhausted through a single central outlet duct to the baghouse for the removal of particulate matter. The bagfilters are pulse jet filters. Emissions from the pelletizer will include VOC, PM, PM_{10}, $PM_{2.5}$ and those associated with combustion. Additionally, during the drying operation, volatile organics in the binder additive are emitted, including methanol and methyl acetate.

2.5 GREEN PELLET SCREENING

Green pellets are conveyed from the pelletizer to the green pellet screens via a bucket elevator. The screens will consist of two large units, which stack multiple screens in one housing unit thus reducing the dust collection effort from traditional screens. Oversize and undersize particles are recycled back into the process while the on-sized particles are conveyed into the kiln for further processing. Oversized particles are diverted through a cage mill for particle reduction and then re-fed to the pelletizer feed bin. Undersized particles are diverted directly back to the pelletizer feed bin.

Expected emissions from the green pellet screening operations are PM, PM_{10} and $PM_{2.5}$. Particulate emissions are controlled by baghouses and bin vent filters, depending on the operation. The storage bins are equipped with bin vent filters with pulse jets that allow the material to recycle directly back into the process.

2.6 CALCINING/SINTERING

On-sized green pellets are conveyed to the kiln feed bin via conveyors and bucket elevator. The green pellets are metered into the charge end of a counterflow rotary kiln where they are slowly dried and calcined. The green pellets or proppant beads need to be slowly heated to drive off moisture and other impurities.

The rotary calciner rotates as it fires a 49.3 MM BTU/Hr burner to a maximum of 3,000 degrees Fahrenheit and is capable of heating the green proppant material at a very slow rate to release bound moisture and volatiles. The natural gas low NO_X burner (propane backup) fires into the material feed stream so that exhaust gases travel counterflow to the incoming green proppant beads.

The rotary calciner also includes a separate rotary cooler that introduces cooling air in the discharge end of the cooler. Cooling airflow is the result of the induced draft fan located downstream of the calciner located between the control device and prior to the stack.

Expected emissions from the calcination process include all criteria pollutants and HAPs (HCl and HF). Emissions from the kiln are routed to a catalytic baghouse system for multi-pollutant control, which controls particulates, NO_X, and acid gases (HF, HCl, and SO_2). Ammonia and sodium bicarbonate are injected into the exhaust gas stream to react with the NO_X and acid gases, respectively. The aqueous ammonia will be drawn from the same storage tanks that feed the process. Sodium bicarbonate will be stored in a silo. The particulate matter generated from the process and flue gas reactions are collected on the filters. Dust collected from the kiln baghouse is sent to another baghouse located at the pelletizer that feeds the dust back into the process at the pelletizer feed bin.

2.7 FINISHING

The calcined and sintered pellets are conveyed from the kiln cooler via bucket elevator to the final product screens. Screening is conducted at two levels with the on sized finished proppant pellets being conveyed to the quality control bins and off-sized proppant pellets recycled back to the kiln for further processing. Pellets are quality tested and if they pass quality control are sent to the storage silos awaiting shipping. Dust collection will occur at transfer points and diverted to a common baghouse. The dust collected at this baghouse is discarded.

The storage silos are located outside and hold finished product waiting for shipping via railcar. Each storage silo and storage bin is equipped with a bin vent with filter. Finished pellets are conveyed to the railcar loading spout and into railcars for delivery to the customer. Dust collection in this area occurs at product transfer points and is collected to a common baghouse.

2.8 SUPPORTING OPERATIONS

The proposed proppant plant will include the following supporting operations:

- On-site research and development and QA/QC labs;
- Two (2) natural-gas fired boilers with propane backup, each rated at 9.8 MMBtu/hr;
- Three (3) 60,000 gallon storage tanks for propane as backup fuel for all natural gas-fired units;
- One (1) 14,250 gallon dispersant tank;
- Two (2) emergency generators, each power by a pair of 500kW diesel engines;
- Two (2) 2,375 gallon storage tanks for the emergency engines;
- One (1) 7,000 gallon aboveground storage tank for diesel fuel for site vehicles;
- One (1) 1,000 gallon aboveground storage tank for diesel fuel for site vehicles; and
- Two (2) aqueous ammonia storage tanks for process pH control and control device operation.

3. SAMPLE EMISSION SOURCE CALCULATIONS

Air emissions occur as the result of material handling (raw material and product), pelletization, calcining, and the combustion of natural gas and propane. This section includes sample calculations for each operation, as well as a summary of potential emissions. Detailed emission calculations are included in Appendix C.

Potential emissions were calculated assuming maximum production on a short-term (i.e., hourly) basis and continuous operation (i.e., 8,760 hours/year). As there are no special startup or shutdown procedures for any of the operations (e.g., control device bypass, different startup fuel), emissions from startup and shutdown are less than the potential emissions calculated in the application.

3.1 MATERIAL HANDLING

Particulate matter emissions from various units throughout the process will be controlled by baghouses or bin vent filters. PM Emissions were calculated based on the exhaust grain loading rate of the baghouses. For smaller bin vent filters and baghouses, the exit grain loading is 0.005 grains per dry standard cubic foot (gr/dscf), for the pelletizer and kiln baghouses, the exit grain loading is 0.01 gr/dscf. A sample calculation is provided below.

Hourly PM Emissions –Green Pellet Screening Baghouse (13-12-1215):

$$\text{PM Emissions }\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Exit Grain Loading Rate }\left(\frac{\text{gr}}{\text{dscf}}\right) \times \left(\frac{1\text{ lb}}{7{,}000\text{ gr}}\right) \times \text{Exhaust Flow }\left(\frac{\text{dscf}}{\text{hr}}\right) \times \left(\frac{60\text{ min}}{\text{hr}}\right)$$

$$\text{PM Emissions }\left(\frac{\text{lb}}{\text{hr}}\right) = 0.005\ \left(\frac{\text{gr}}{\text{scf}}\right) \times \left(\frac{1\text{ lb}}{7{,}000\text{ gr}}\right) \times 7{,}488\ \left(\frac{\text{dscf}}{\text{min}}\right) \times \left(\frac{60\text{ min}}{\text{hr}}\right)$$

$$\text{PM Emissions } = 0.32\ \left(\frac{\text{lb}}{\text{hr}}\right)$$

Potential Annual PM Emissions –Green Pellet Screening Baghouse (13-12-1215):

$$\text{PM Emissions (tpy)} = \text{Hourly Emission Rate }\left(\frac{\text{lb}}{\text{hr}}\right) \times \text{Hours of Operation }\left(\frac{\text{hr}}{\text{yr}}\right) \div 2{,}000\ \left(\frac{\text{lb}}{\text{ton}}\right)$$

$$\text{PM Emissions (tpy)} = 0.32\left(\frac{\text{lb}}{\text{hr}}\right) \times 8{,}760\ \left(\frac{\text{hr}}{\text{yr}}\right) \div 2{,}000\ \left(\frac{\text{lb}}{\text{ton}}\right)$$

$$\text{PM Emissions (tpy)} = 1.41\text{ (tpy)}$$

PyraMax assumes that all PM is PM_{10}. To determine the emission rate of $PM_{2.5}$ from material handling, PyraMax used EPA's PM calculator.[1] As there was no data available for clay processing,

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[1] http://www.epa.gov/ttn/chief/eiinformation.html

PyraMax selected source classification codes (SCC) 30500711 (cement wet process screening) for raw material transfers, silos, and storage bins and 30500719 (cement load out) for loading operations. The ratio of controlled $PM_{2.5}$ emissions (0.30 lb/hr) and controlled PM_{10} emissions (0.57 lb/hr) was multiplied by the PM_{10} emissions calculated using the outlet grain loading rate calculation.

A sample calculation for the green pellet baghouse (13-12-1215) is provided below

$$\text{PM}_{2.5}\text{ Emissions }\left(\frac{\text{lb}}{\text{hr}}\right) = \text{PM}_{10}\text{ Emissions }\left(\frac{\text{lb}}{\text{hr}}\right) \times \frac{\text{EPA Calculator PM}_{2.5}\text{ Emissions }\left(\frac{\text{lb}}{\text{hr}}\right)}{\text{EPA Calculator PM}_{10}\text{ Emissions }\left(\frac{\text{lb}}{\text{hr}}\right)}$$

$$\text{PM}_{2.5}\text{ Emissions }\left(\frac{\text{lb}}{\text{hr}}\right) = 0.32\left(\frac{\text{lb}}{\text{hr}}\right) \times \frac{0.30\ \left(\frac{\text{lb}}{\text{hr}}\right)}{0.57\ \left(\frac{\text{lb}}{\text{hr}}\right)}$$

$$\text{PM}_{2.5}\text{ Emissions }\left(\frac{\text{lb}}{\text{hr}}\right) = 0.17\ \left(\frac{\text{lb}}{\text{hr}}\right)$$

Particulate emissions from raw material handling are exclusively filterable PM. Condensable particulate matter emissions from the kiln are addressed in Section 3.4.

3.2 ADDITIVE EMISSIONS

The additive binder contains one percent volatiles in the form of methanol and methyl acetate. These VOC are emitted during storage silo filling and in the pelletizer.

To calculate emissions from the filling of the storage vessel, PyraMax used a vapor displacement equation. As the silo will be contained indoors in a temperature controlled building, there are no breathing emissions associated with the storage of the binder. Short term (i.e., hourly) emissions assume the silo is filled in one hour. Annual emissions assume one fill per day (i.e., 365 fills per year). A sample calculation is provided below.

$$\text{Methanol Emissions }\left(\frac{\text{lb}}{\text{fill}}\right) = \frac{\text{Vol. of Air Displaced }\left(\frac{\text{ft}^3}{\text{fill}}\right) \times \text{Partial Pressure of MeOH (psi)} \times \text{MW MeOH }\left(\frac{\text{lb}}{\text{lb mol}}\right)}{\text{Temperature(R)} \times \text{R}\left(\frac{\text{ft}^3\text{psi}}{\text{lb mol R}}\right)}$$

$$\text{Methanol Emissions }\left(\frac{\text{lb}}{\text{fill}}\right) = \frac{2{,}161\ (\text{ft}^3) \times 2.60\ (\text{psi}) \times 32\left(\frac{\text{lb}}{\text{lb mol}}\right)}{555.67(\text{R}) \times 10.73\left(\frac{\text{ft}^3\text{psi}}{\text{lb mol R}}\right)}$$

$$\text{Methanol Emissions }\left(\frac{\text{lb}}{\text{fill}}\right) = 30.2\left(\frac{\text{lb}}{\text{fill}}\right)$$

To calculate emissions from the pelletizer, PyraMax used a mass balance and assumed all VOC in the additive would be flashed off and emitted from the pelletizer baghouse. It is important to note that this results in double counting methanol emissions (e.g., not subtracting emission from silo filling). A sample calculation is provided below.

$$\text{Methanol Emissions }\left(\frac{\text{lb}}{\text{fill}}\right) = \text{Wt fraction Methnaol (wt\%)} \times \text{Binder Usage }\left(\frac{\text{lb}}{\text{hr}}\right)$$

Ammonia emissions from the pH adjuster were calculated using a similar methodology. Ammonia emissions were assumed to all exhaust at the pelletizer. PyraMax has assumed that all ammonia present is the pH adjuster is NH_3.

3.3 COMBUSTION EMISSIONS

The proposed facility will have several combustion sources, including boilers, pelletizer heaters, and kiln burners. Each of the combustion units will fire natural gas with propane as a backup fuel. Combustion emissions from these sources were calculated by multiplying the fuel specific U.S. EPA AP-42 emission factor for each pollutant by the potential fuel usage for each unit. For the pelletizer heaters, NO_X and CO emission factors were provided by the vendor. All burners will be low NO_X burners, therefore emission factors for low NO_X burners were used as noted in the detailed calculations.

Potential hourly emissions were calculated for each fuel assuming maximum heat input capacity and the pollutant-specific emission factor. Potential annual emissions for each fuel were calculated based on the potential hourly emission rate and continuous operation (8,760 hours per year). Potential emissions for each emission unit are the worst-case emissions calculated for each of the two fuels on a pollutant by pollutant basis.

An example calculation for potential emissions of CO from natural gas combustion in one of the boilers is as follows:

<u>Potential Hourly CO Emissions – 9.8 MMBtu/hr Boiler – Natural Gas</u>:

$$\text{Potential CO Emissions}\left(\frac{\text{lb}}{\text{hr}}\right) = \frac{\text{CO Emission Factor }\left(\frac{\text{lb}}{\text{MMcf}}\right) \times \text{ Heat Input Rating }\left(\frac{\text{MMBtu}}{\text{hr}}\right)}{\text{Heating Value of Natural Gas}\left(\frac{\text{MMBtu}}{\text{MMscf}}\right)}$$

$$\text{Potential CO Emissions}\left(\frac{\text{lb}}{\text{hr}}\right) = \frac{84\ \left(\frac{\text{lb}}{\text{MMcf}}\right) \times\ 9.8\ \left(\frac{\text{MMBtu}}{\text{hr}}\right)}{1{,}000\left(\frac{\text{MMBtu}}{\text{MMscf}}\right)}$$

$$\text{Potential CO Emissions}\left(\frac{\text{lb}}{\text{hr}}\right) = 0.82\left(\frac{\text{lb}}{\text{hr}}\right)$$

Potential Annual CO Emissions – 9.8 MMBtu/hr Boiler – Natural Gas:

$$\text{Potential CO Emissions (tpy)} = \text{Maximum Hourly Emission Rate} \left(\frac{\text{lb}}{\text{hr}}\right) \times 8{,}760 \left(\frac{\text{hr}}{\text{yr}}\right) \div 2{,}000 \left(\frac{\text{lb}}{\text{ton}}\right)$$

$$\text{Potential CO Emissions (tpy)} = 0.82 \left(\frac{\text{lb}}{\text{hr}}\right) \times 8{,}760 \left(\frac{\text{hr}}{\text{yr}}\right) \div 2{,}000 \left(\frac{\text{lb}}{\text{ton}}\right)$$

$$\text{Potential CO Emissions (tpy)} = 3.61\ \text{(tpy)}$$

Greenhouse gas emissions for all combustion sources were calculated using the emission factors provided in Tables C-1 and C-2 of 40 CFR 98 Subpart C (the Greenhouse Gas Mandatory Reporting Rule). Each greenhouse gas pollutant was multiplied with the respective global warming potential from 40 CFR 98 Subpart A Table A-1 to determine emissions of CO_2equivalent (CO_2e).

3.4 KILN EMISSIONS

In addition to emissions from combustion, there are additional pollutants emitted from the calcining of the clay. These pollutants are either liberated from the raw material (e.g., HF, HCl, SO_2, CO_2) or as a result of thermal formation in the kiln (e.g., NO_X, CO). Elemental lead and mercury emissions from the proposed facility are negligible due to the low concentrations in the raw material feed.

For SO_2, and CO_2, emissions were calculated using core samples from the mine site of the raw material clay. For each pollutant, the maximum concentration in any of the samples for each constituent was used. As the tests reported sulfur (S) and carbon (C) content, the values from the samples were converted to SO_2 and CO_2. A sample calculation is as follows:

$$\text{Potential } SO_2 \text{ Emissions} \left(\frac{\text{lb}}{\text{hr}}\right) = \text{Conc. of S in Clay(ppm)} \times \text{ Clay Throughput } \left(\frac{\text{lb}}{\text{hr}}\right) \times \frac{\text{lb mol S}}{\text{32 lb S}} \times \frac{\text{lb mol } SO_2}{\text{lb mol S}} \times \frac{\text{64 lb } SO_2}{\text{lb mol } SO_2}$$

For HF and HCl, the calculation methodology was the same as that for SO_2 and CO_2 emission calculations, with the fluoride and chloride converted to HF and HCl. However, mine specific data were not available for fluorides and chlorides. Therefore, PyraMax used published data for fluoride concentration from Georgia clay.[2] As the fluoride concentration data are not specific to the mine selected, PyraMax has included a safety factor of 50% in the fluoride concentration. PyraMax calculated the chloride concentration based on a ratio of controlled HF and HCl emission limits and percent reductions in Table 1 of 40 CFR 63 Subpart KKKK (National Emission Standards for Hazardous Air Pollutants for Clay Ceramics Manufacturing) for new tunnel kilns with capacities greater than 10 tons per hour. The calculation is provided below:

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[2] "Fluoride Content of Clay Minerals and Argillaceous Earth Materials," Clay and Clay Minerals., Vol 25, pg 77, 1977.

$$\text{Chloride Conc(ppm)} = \text{Fluoride Conc.(ppm)} \times \frac{\dfrac{\text{HCl Emission limit } \left(\frac{\text{lb}}{\text{ton}}\right)}{(1\text{-\% HCL Reduction})}}{\dfrac{\text{HF Emission limit } \left(\frac{\text{lb}}{\text{ton}}\right)}{(1\text{-\% HF Reduction})}}$$

$$\text{Chloride Conc(ppm)} = 210\text{(ppm)} \times \frac{\dfrac{0.056 \left(\frac{\text{lb}}{\text{ton}}\right)}{(1\text{-}85\%)}}{\dfrac{0.057 \left(\frac{\text{lb}}{\text{ton}}\right)}{(1\text{-}90\%)}}$$

$$\text{Chloride Conc(ppm)} = 140\text{(ppm)}$$

PyraMax has assumed that all fluoride in the raw material is converted to HF. Therefore, emissions of fluorides other than HF are assumed to be negligible from the calcining process. Similarly, PyraMax has assumed that all sulfur is converted to SO_2, and, therefore, emissions of other sulfur-containing compounds, such as hydrogen sulfide (H_2S), sulfuric acid mist (H_2SO_4), and total reduced sulfur (TRS) are assumed negligible.

There is no condensable particulate matter information available for clay calcining. Therefore, PyraMax used condensable emission factors from wet process cement production. The condensable particulate matter emission factor used was the sum of the kiln and the cooler emission factors for cement kilns as the proposed facility has both unit operations.

Emissions of NO_X from the kilns were calculated using emission factors and engineering estimates based on similar operations and industries. Similarly, emissions of CO were calculated using representative emission factors from U.S. EPA AP-42.

Controlled emissions are calculated using vendor provided emissions reduction for each pollutant controlled (HF, HCl, SO_2, and NO_X).

3.5 CONTROL DEVICE EMISSIONS

Emissions from the kiln will be controlled using a catalytic baghouse system. The catalytic baghouse system uses ammonia as a reagent for NO_X control. Unreacted ammonia injected into the exhaust stream is emitted from the baghouse exhaust stack. Emissions of ammonia from the kilns were calculated using a vendor supplied ammonia slip concentration.

The usage of the proposed dry sorbent injection system will result in potential CO_2 and fluoride (as sodium fluoride) emissions due to the chemical reaction between the sorbent used and HCl, HF, and SO_2 the pollutants for which sorbent may be utilized to control. PyraMax estimated the potential emissions according to the mass balance equation provided in 40 CFR 98.33(d)(1), assuming sodium bicarbonate ($NaHCO_3$) will be used as the sorbent. HCl, HF, and SO_2 are removed from the exhaust stream when reacted with the dry sorbent and CO_2 is released according to the following equations:[3]

$$NaHCO_3 + HCl \rightarrow NaCl + CO_2 + H_2O$$

$$2NaHCO_3 + SO_2 \rightarrow Na_2SO_3 + 2CO_2 + H_2O$$

$$NaHCO_3 + HF \rightarrow NaF + CO_2 + H_2O$$

Estimated emissions of CO_2 are predicated based on an assumed annual quantity of sodium bicarbonate injected. The quantity required was calculated using the uncontrolled emission rates, molecular weight, molar conversion, and a ten percent safety factor. A sample calculation is provided below:

$$\mathrm{NaHCO_3\ Injection\ Rate}\ \left(\frac{\mathrm{lb}}{\mathrm{hr}}\right) = \frac{\mathrm{Uncontrolled\ HF\ Emission\ Rate}\ \left(\frac{\mathrm{lb}}{\mathrm{hr}}\right)}{\mathrm{MW\ HF}\ \left(\frac{\mathrm{lb}}{\mathrm{lb-mol}}\right)} \times \left(\frac{\mathrm{2\ mole\ NaHCO_3}}{\mathrm{1\ mole\ HF}}\right) \times \mathrm{MW\ NaHCO_3}\ \left(\frac{\mathrm{lb}}{\mathrm{lb-mol}}\right) \times (1 + 10\%)$$

3.6 MISCELLANEOUS EMISSION SOURCES

The facility will operate two diesel-fired emergency generators with ultra low sulfur fuel. Each generator is powered by two (2) engines each rated at 500 kilowatts (kW). Emissions were calculated using a combination of U.S. EPA AP-42 emission factors and emission limits contained in 40 CFR 60 Subpart IIII. In the calculation of annual emissions, the number of hours in non-emergency use is limited to 100 hours per year per 40 CFR 63 Subpart ZZZZ.

Emissions from the diesel storage tanks were calculated using EPA's TANKS 4.0.9d program, assuming one turnover per month.

3.7 EMISSIONS SUMMARY

Facility-wide potential emissions are summarized in Table 3-1 on a short-term (i.e., hourly) and annual basis.

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[3] NaCl, Na_2SO_3,and H_2O are not considered air pollutants.

TABLE 3-1. POTENTIAL EMISSION SUMMARY

Pollutant	Potential Emissions (lb/hr)	 (tpy)
PM	36.72	157.00
PM_{10}	36.72	157.00
$PM_{2.5}$	25.21	106.59
SO_2	28.88	102.71
NO_X	97.52	350.78
CO	154.09	608.10
VOC	119.13	129.73
CO_2e	41,305	167,570
Fluorides	0.04	0.19

4. REGULATORY APPLICABILITY ANALYSIS

The proposed proppant plant is potentially subject to both state and Federal air regulations. This section addresses the applicability or non applicability of pertinent state and Federal regulations.

4.1 TITLE V OPERATING PERMITS

The Title V program was established as part of the 1990 Clean Air Act Amendments and is in the federal regulations at 40 CFR Part 70-71. Georgia has developed their own program under 40 CFR Part 70, which is provided in Chapter 391-3-1-.03(10) of the Georgia Rules for Air Quality Control. Title V requires that all new and existing major sources of air emissions obtain federally approved state administered operating permits. A major source as defined under the Title V program is a facility that has the potential to emit either more than 100 tons per year for any criteria pollutant, more than 10 tons per year for any single hazardous air pollutant (HAP), and more than 25 tons per year for all HAP. Additionally, 40 CFR Part 70.2 defines facilities with potential emissions greater than 100,000 tpy of CO_2e are subject to regulation under the Title V permitting program. Potential emissions of multiple pollutants exceed the Title V major source threshold. PyraMax will submit a complete Title V permit application within twelve months of commencement of operation.

4.2 PSD PERMITTING PROGRAM

The PSD program regulates emissions from major stationary sources of regulated air pollutants. For the purposes of the PSD program, a major stationary source is defined in 40 CFR 52.21(b)(1)[4] as any one of the following:

1. *Any of the stationary sources of air pollutants listed in paragraph (b)(1)(a) of 40 CFR 52.21 which emits, or has the potential to emit, 100 tons per year or more of any regulated New Source Review (NSR) pollutant ;*
2. *Notwithstanding the stationary source size specified in paragraph (b)(1)(a), any stationary source which emits, or has the potential to emit, 250 tons per year or more of a regulated NSR pollutant; or*
3. *Any physical change that would occur at a stationary source not otherwise qualifying under paragraph (b)(1), as a major stationary source, if the changes would constitute a major stationary source by itself.*

Also, issuance of the U.S. EPA Tailoring Rule produces applicability requirements regarding Greenhouse Gas (GHG) emissions to the PSD permitting program.[5] The PSD major source threshold

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[4] Incorporated by reference with exceptions in the Georgia Rules for Air Quality Control, Chapter 391-3-1-.02(7)(a)(iii).

[5] Rule was published in the Federal Register on June 3, 2010, and became effective August 2, 2010. Federal Register Vol. 75, No. 106, June 3, 2010, pages 31541 – 31608. http://www.gpo.gov/fdsys/pkg/FR-2010-06-03/pdf/2010-11974.pdf

for GHGs is 100,000 tpy CO_2e, and 100/250 tpy mass basis depending on the industrial category of the facility.

The raw material will be provided from a mine located approximately 20 miles from the proposed site location. In accordance with the Federal PSD regulations, a stationary source is defined in 40 CFR 52.21(b)(5) and 40 CFR 52.21(b)(6) as:

(5) Stationary source means any building, structure, facility, or installation which emits or may emit a regulated NSR pollutant.

(6) Building, structure, facility, or installation means all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control) except the activities of any vessel. Pollutant-emitting activities shall be considered as part of the same industrial grouping if they belong to the same "Major Group" (i.e., which have the same first two digit code) as described in the Standard Industrial Classification Manual, 1972, as amended by the 1977 Supplement (U.S. Government Printing Office stock numbers 4101-0066 and 003-005-00176-0, respectively).

EPA's New Source Review Workshop Manual states "the industrial grouping of a source is classified in accordance with the primary activity at the site, which is determined by its principal product or group of products produced or distributed or by the service it renders".[6] Furthermore, the manual states that support facilities are to be included within the boundary of a stationary source. Support facilities are "facilities that convey, store, or otherwise assist in the production of the principle product".[7]

Therefore, there are three issues that must be evaluated when determining the stationary source boundary of the proposed plant. In order for a group of emission units to be considered part of the same stationary source, they must meet all of the following criteria:

- Belong to the same industrial grouping (including support facilities),
- Be located on one or more contiguous or adjacent properties, and
- Be under the control of the same person (or persons under common control).

Industrial Grouping

The existing mine site and proposed plant belong to the same industrial grouping. The primary activity of the mine is the mining and quarrying of nonmetallic minerals, except fuels, which is classified under a separate two-digit SIC code (14) than the proposed proppant plant, which produces a product in the stone, clay, glass, and concrete products under the two-digit SIC code of 32. Furthermore, the existing mine site would not be considered a support facility since the mine can supply clay to any site. Therefore, the existing mine site and proposed plant do not meet the first criteria of a single stationary source.

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[6] New Source Review Workshop Manual, EPA Air Quality Management Division, Draft 1990.

[7] Ibid

Contiguous or Adjacent

The existing mine site and proposed plant are located approximately 20 miles apart. The transport between the two properties will require travel on public roads and through land not owned or leased by either the mine or PyraMax. Therefore, the pollutant-emitting activities at the existing mine site and proposed plant do not meet the second criteria of a single stationary source.

Common Control

EPA's permit regulations do not provide a definition for control. However, through regulation, guidance, and individual determinations, the EPA has established several mechanisms for use by sources and permitting authorities in determining common control as used in the definition of "major source" under Title I -HAP, Title I – NSR, and Title V of the Act. First, common control can be established through ownership (i.e., same parent company or a subsidiary of the parent company). Second, common control can be established if an entity such as a corporation has decision-making authority over the operations of a second entity through a contractual agreement or voting interest.[8] If common control is not established by the first two mechanisms, then one should next look at whether there is a contract for service relationship between the two companies or if a support/dependency relationship exists between the two companies in order to determine whether a common control relationship exists.[9,10,11]

Common Ownership and Authority

The existing mine site and proposed plant are not under common ownership. They are neither owned by the same parent company, subsidiaries of the same parent company, or part of a joint venture of any common parent companies. Furthermore, none of the companies that own the existing mine site or proposed plant can exert decision-making authority over the operations at the other facility through a voting interest. Furthermore, PyraMax and the mine site do not jointly own production equipment or real property at the site. Therefore, in this case, common control is not established through common ownership or authority.

Contractual and Support Relationships

Agreements have been developed to govern the relationship between PyraMax and the mine site. In a letter from William Spratlin (EPA) to the Iowa Department of Natural Resources, he states that relationships between companies that are located on common property are usually governed by contractual, lease, or other agreements that establish how the facilities interact with one another.[12]

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[8] 45 FR 59874, 59878, September 11, 1980.

[9] John S. Seitz Memorandum, "Major Source Determinations for Military Installations under the Air Toxics, New Source Review, and Title V Operating Permit Programs of the Clean Air Act (Act)", August 2, 1996.

[10] Letter from William Spratlin, Division Director, Environmental Protection Agency, Region 7, Air, RCRA and Toxics Division, to Peter Hamlin, Chief, Iowa Department of Natural Resources, Air Quality Bureau, September 18, 1995.

[11] Letter from Steven C. Riva, Chief, Environmental Protection Agency, Permitting Section, Air Programs Branch, to Michael L. Rodburg, Esq., Lowenstein, Sandler, Kohl, Fisher & Boylan, November 25, 1997.

[12] Letter from William Spratlin, Division Director, Environmental Protection Agency, Region 7, Air, RCRA and Toxics Division, to Peter Hamlin, Chief, Iowa Department of Natural Resources, Air Quality Bureau, September 18, 1995.

These “companion facilities” must explain how they interact with each other to demonstrate the absence of common control. Typical plant interrelationship questions asked by EPA in determining common control are listed as follows:

1. Do the facilities share common workforces, plant managers, security forces, corporate executive officers, or board of executives?
2. Do the facilities share equipment, other property, or pollution control equipment? What does the contract specify with regard to pollution control responsibilities of the contractee? Can the managing entity of one facility make decisions that affect pollution control at the other facility
3. Do the facilities share common payroll activities, employee benefits, health plans, retirement funds, insurance coverage, or other administrative functions?
4. Do the facilities share intermediates, products, by-products, or other manufacturing equipment? Can the new source purchase raw materials from and sell products or by products to other customers? What are the contractual arrangements for providing goods and services?
5. Who accepts the responsibility for compliance with air quality control requirements? What about for violations of the requirements?
6. What is the dependency of one facility on the other? If one shuts down, what are the limitations on the other to pursue outside business interests?
7. Does one operation support the operation of the other? What are the financial arrangements between the two entities?

If the facility responds affirmatively to any of these questions, it is generally assumed that the facilities are under common control. The contractual agreements in place do not affirm any of the above statements. Therefore, the existing mine site and proposed plant are not under common control.

To evaluate whether the proposed plant will be subject to requirements under the PSD program, the annual potential emissions of regulated pollutants from the proposed plant are compared with the PSD major source thresholds. The proposed plant is not one of the 28 named source categories, and therefore has a PSD major source threshold of 250 tpy. The proposed proppant plant will be a new major source under the PSD program as potential emissions of at least one pollutant exceed the major source threshold.

For new sources which are major for at least one regulated pollutant, all other pollutants which are emitted from the facility should be compared against the PSD Significant Emission Rates (SERs) listed in Table 4-1.

TABLE 4-1. PSD SIGNIFICANT EMISSION RATES

Pollutant	Significant Emission Rates (tpy)
PM	25
PM_{10}	15
$PM_{2.5}$	10
SO_2	40
NO_X	40
CO	100
VOC	40
CO_2e	75,000 [1]
Fluorides	3

[1] As provided under "subject to regulation" definitions in 40 CFR 51.166(b)(48) and 52.21(b)(49). Unlike other pollutant SERs, GHG SER is not listed in 40 CFR 51.166(b)(23) or 52.21(b)(23).

In Table 4-2 below, the facility-wide potential emission rates of each regulated air pollutant emitted from the facility are compiled and compared against the SERs and major source thresholds.

TABLE 4-2. PROPOSED PROJECT POTENTIAL EMISSIONS COMPARED WITH PSD SIGNIFICANT EMISSION RATES

Pollutant	Major Source Threshold (tpy)	Significant Emission Rates (tpy)	Potential Emissions (tpy)
PM	250	25	157.00
PM_{10}	250	15	157.00
$PM_{2.5}$	250	10	106.59
SO_2	250	40	102.71
NO_X	250	40	350.78
CO	250	100	608.10
VOC	250	40	129.73
CO_2e	100,000/250[1]	75,000	167,570
Fluorides	250	3	0.19

[1] Emissions must exceed 100,000 tpy on a CO_2e basis and 250 tpy on a mass basis.

As shown in Table 4-2, the proposed proppant project will result in potential emissions exceeding the major source threshold for CO, NO_X, SO_2, GHG, PM/PM_{10}/$PM_{2.5}$ and VOC emissions. Therefore, the proposed proppant plant is required to undergo PSD review for these pollutants since each applicable pollutant is in attainment under the New Source Review (NSR) program.

For pollutants subject to PSD review, the following requirements of a PSD analysis are addressed in this application.

1. Demonstration of the application of Best Available Control Technology (BACT) for new and modified emission units [40 CFR 52.21(b)(1), refer to Section 5 of Volume I].
2. Source Impact Analysis [40 CFR 52.21(k), refer to Volume II].
3. Projected growth analysis [40 CFR 52.21(o)(2), refer to Volume II].
4. Analysis of the effects on soils, vegetation, and visibility [40 CFR 52.21 (o)(1)&(3), refer to Volume II].

4.3 NEW SOURCE PERFORMANCE STANDARDS

The Standards of Performance for New Stationary Sources (NSPS) require new, modified or reconstructed sources to control emissions to the level achievable by the best demonstrated technology as specified in the applicable provisions. Moreover, any source subject to an NSPS is also subject to the general provisions of NSPS Subpart A, except as noted. Following is a summary of applicability determinations for NSPS regulations of relevance to the proposed proppant plant.

4.3.1 NSPS SUBPART KB – STANDARDS OF PERFORMANCE FOR NONMETALLIC MINERAL PROCESSING PLANTS

NSPS Subpart Kb potentially applies to each storage vessel with a capacity greater than or equal to 75 cubic meters (m^3) that is used to store volatile organic liquids (VOL) for which construction, reconstruction, or modification is commenced after July 23, 1984.

The proposed facility will have several storage tanks. These tanks include:

- Three (3) 60,000 gallon propane tanks,
- One (1) 14,250 gallon dispersant tanks;
- One (1) 1,000 gallon diesel fuel tank,
- One (1) 7,000 gallon diesel fuel tank,
- Two (2) 2,375 gallon diesel fuel tanks, and
- Two (2) 19,000 gallon aqueous ammonia storage tanks.

All tanks but the propane storage tanks have capacities less than 75 m^3 and are therefore not subject to NSPS Subpart Kb. The propane storage tanks are designed to operate in excess of 204.9 kPa and without emissions to the atmosphere. Therefore, the propane storage tanks are exempt from NSPS Subpart Kb per 40 CFR §60.110b(d)(2).

4.3.2 NSPS SUBPART DC – STANDARDS OF PERFORMANCE FOR SMALL INDUSTRIAL-COMMERCIAL-INSTITUTIONAL STEAM GENERATING UNITS

NSPS Subpart Dc applies to each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/hr)) or less, but greater than or equal to 2.9 MW (10 MMBtu/hr).

Steam generating unit means a device that combusts any fuel and produces steam or heats water or heats any heat transfer medium. This term includes any duct burner that combusts fuel and is part of a combined cycle system. This term does not include process heaters as defined in this subpart.

Process heater means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst. The proposed plant will have several combustion units. The pelletizer heaters and the kiln burners meet the definition of process heaters as they are not used to produce steam, heat water, or heat any heat transfer medium, but rather are used to heat materials to initiate or promote chemical reactions.

The boilers at the site meet the definition of steam generating units. However, the maximum design heat input capacity of each unit is less than 10 MMBtu/hr. Therefore, NSPS Subpart Dc does not apply to the boilers.

4.3.3 NSPS SUBPART OOO – STANDARDS OF PERFORMANCE FOR NONMETALLIC MINERAL PROCESSING PLANTS

NSPS Subpart OOO applies to the following affected facilities in fixed or portable nonmetallic mineral processing plants: each crusher, grinding mill, screening operation, bucket elevator, belt conveyor, bagging operation, storage bin, enclosed truck or railcar loading station that commences construction, modification, or reconstruction after August 31, 1983. The definition of nonmetallic mineral in 40 CFR §60.671 includes clay.

The raw material and product handling operations include bucket elevators, belt conveyors, screening operations, grinding mills, storage bins, and loading stations, which are affected facilities under NSPS Subpart OOO.

4.3.3.1 EMISSION LIMITS

Affected facilities must meet the stack and fugitive emission limits and compliance requirements in Tables 2 and 3, respectively, of NSPS Subpart OOO within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup as required under 40 CFR §60.8 and §60.11. The requirements in Table 2 of NSPS Subpart OOO apply for affected facilities with capture systems used to capture and transport particulate matter to a control device. The requirements in Table 3 of this subpart apply for fugitive emissions from affected facilities without capture systems and for fugitive emissions escaping capture systems.

If any transfer point on a conveyor belt or any other affected facility is enclosed in a building, then each enclosed affected facility must comply with the emission limits in Tables 2 and 3 of Subpart OOO, or the building enclosing the affected facility or facilities must comply with the following emission limits:

- Fugitive emissions from the building openings (except for vents, defined in 40 CFR §60.671 as an opening through which there is mechanically induced air flow for the purpose of exhausting from a building air carrying particulate matter emissions from one or more affected facilities) must not exceed 7 percent opacity; and
- Vents in the building must meet the applicable stack emission limits and compliance requirements in Table2 of NSPS Subpart OOO.

Any baghouse that controls emissions from only an individual, enclosed storage bin is exempt from the applicable stack PM concentration limit (and associated performance testing), but must meet the applicable stack opacity limit and compliance requirements. This exemption from the stack PM concentration limit does not apply for multiple storage bins with combined stack emissions.

Per 40 CFR §60.672(d), truck dumping of nonmetallic minerals into any screening operation, feed hopper, or crusher is exempt from the requirements of this section.

Per 40 CFR §60.670(a)(2), Subpart OOO does not apply to wet material processing operations. The applicable definitions for this exempt follow:

> *Wet material processing operation(s)* means any of the following:
>
> (1) Wet screening operations (as defined in this section) and subsequent screening operations, bucket elevators and belt conveyors in the production line that process saturated materials (as defined in this section) up to the first crusher, grinding mill or storage bin in the production line…
>
> *Wet screening operation* means a screening operation at a nonmetallic mineral processing plant which removes unwanted material or which separates marketable fines from the product by a washing process which is designed and operated at all times such that the product is saturated with water.
>
> *Saturated material* means, for purposes of this subpart, mineral material with sufficient surface moisture such that particulate matter emissions are not generated from processing of the material through screening operations, bucket elevators and belt conveyors. Material that is wetted solely by wet suppression systems is not considered to be "saturated" for purposes of this definition.

Raw materials handling operations until the mix tank are controlled using partial enclosures and are subject to the limitations in Table 3 to Subpart OOO.

After the mix tank and up until the pelletizer, the materials are saturated and, therefore, are exempt from Subpart OOO. After the pelletizer, the material handling operations are controlled by baghouses and bin vents and/or are located indoors.

Performance tests to demonstrate compliance with opacity limitations require Method 9/22 test methods, while performance tests to demonstrate compliance with particulate matter emission limits use Method 5 or 17 test methods.

4.3.3.2 MONITORING, RECORDKEEPING, AND REPORTING

For operations that use a baghouse to control emissions, PyraMax must conduct quarterly 30-minute visible emissions inspections using EPA Method 22 (40 CFR Part 60, Appendix A–7). The test shall be conducted while the baghouse is operating. The test is successful if no visible emissions are observed. If any visible emissions are observed, PyraMax must initiate corrective action within 24 hours to return the baghouse to normal operation.

PyraMax must record each Method 22 (40 CFR part 60, Appendix A–7) test, including the date and any corrective actions taken, in the logbook required under 40 CFR §60.676(b).

Rather than notifications of the date of construction as required under 40 CFR 60 Subpart A, a notification of the date of initial startup of each affected facility is required to be submitted per 40 CFR §60.676 (h) and (i).

4.3.4 NSPS SUBPART UUU – STANDARDS OF PERFORMANCE FOR CALCINERS AND DRYERS IN MINERAL INDUSTRIES

NSPS Subpart UUU applies to each calciner and dryer at a mineral processing plant that commences construction, modification, or reconstruction after April 23, 1986. Feed and product conveyors are not considered part of the affected facility per 40 CFR §60.730(a). Kaolin is listed in the definition of mineral processing plant.

4.3.4.1 EMISSION LIMITS

Stack particulate emissions from kilns are limited to 0.04 gr/dscf and 10 percent opacity and from the pelletizer dryer are limited to 0.025 gr/dscf and 10 percent opacity. PyraMax shall comply with the emission limitations on and after the date on which the initial performance test required by §60.8 is completed, but not later than 180 days after the initial startup, whichever date comes first.

4.3.4.2 MONITORING, RECORDKEEPING, AND REPORTING

In accordance with 40 CFR §60.734(a), facilities using a dry control device to comply with the mass emission standards of Subpart UUU are required to operate a continuous opacity monitoring system (COMS) to measure opacity. Records of opacity shall be maintained for at least two years.

Semiannual reports noting exceedances of the opacity limits shall be submitted in accordance with 40 CFR §60.735(c). PyraMax shall submit the required notifications in Subpart A, including:

- A notification of the date construction postmarked no later than 30 days after such date [40 CFR §60.7(a)(1)]
- A notification of the actual date of initial startup postmarked within 15 days after such date [40 CFR §60.7(a)(3)]
- A notification of the date upon which demonstration of the continuous monitoring system performance commences in accordance with 40 CFR §60.13(c). Notification shall be postmarked not less than 30 days prior to such date [40 CFR §60.7(a)(5)]
- A notification that continuous opacity monitoring system data results will be used to determine compliance with the applicable opacity standard during a performance test required by 40 CFR §60.8 in lieu of Method 9 observation data. This notification shall be postmarked not less than 30 days prior to the date of the performance test [40 CFR §60.7(a)(7)]

4.3.5 NSPS SUBPART IIII – STANDARDS OF PERFORMANCE FOR STATIONARY COMPRESSION IGNITION INTERNAL COMBUSTION ENGINES

NSPS Subpart IIII applies to stationary compression ignition (CI) internal combustion engines (ICE) manufactured after April 1, 2006. PyraMax will be constructing two emergency generators, power by four diesel-fired 670 horsepower (hp), 500 kilowatt (kW) engines. The proposed units meet the definition of emergency stationary ICE in 40 CFR §60.4219.

4.3.5.1 EMISSION LIMITS

Per 40 CFR §60.4202(a)(2), the emergency use engines must meet the requirements of 40 CFR §89.112/113 (Tier 3). Table 4-3 lists the emission limits that are applicable to the proposed generators.

TABLE 4-3. TIER 3 EMISSION LIMITS

Pollutant	Emission Limit (g/kW-hr)
NMHC + NO_X	4.0
CO	3.5
PM	0.20

Additionally, the generators will have to meet the fuel requirements of 40 CFR §80.510(a) and (b), which state that fuel oil combusted in CI ICE must meet the following requirements:

- Maximum sulfur content of 15 ppm; and
- Minimum Centane index of 40 or maximum aromatic content of 35% by volume.

PyraMax will purchase an engine certified to meet the emission limits and use fuel that meets the required specifications.

4.3.5.2 MONITORING, RECORDKEEPING, AND REPORTING

PyraMax must operate and maintain the stationary CI internal combustion engine and according to the manufacturer's written instructions or procedures developed by PyraMax that are approved by the engine manufacturer. In addition, PyraMax may only change those settings that are permitted by the manufacturer. The engines are required to be equipped with a non-resettable hour meter prior to startup of the engine.

Per §60.4211(e), emergency stationary ICE may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State, or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per year. There is no time limit on the use of emergency stationary ICE in emergency situations.

No initial notifications are required for emergency engines, per §60.4214(b). PyraMax must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. PyraMax must record the time of operation of the engine and the reason the engine was in operation during that time.

No other NSPS potentially apply to the proposed proppant plant operations.

4.4 NATIONAL EMISSION STANDARDS FOR HAP (NESHAP)

National Emissions Standards for Hazardous Air Pollutants are emission standards that regulate HAP emissions and are generally only applicable to major sources of HAP. A HAP major source is defined as a source that has potential emissions in excess of 25 tpy for total combined HAP and/or potential emissions in excess of 10 tpy for any individual HAP. The NESHAP allowable emission limits are established on the basis of a maximum achievable control technology (MACT) determination for the particular major source. Federal regulations for HAP are listed at 40 CFR 61 and 40 CFR 63.

4.4.1 40 CFR 63 SUBPART B – REQUIREMENTS FOR CONTROL TECHNOLOGY DETERMINATIONS FOR MAJOR SOURCES IN ACCORDANCE WITH CLEAN AIR ACT SECTIONS, SECTIONS 112(G) AND 112(J)

PyraMax is proposing to construct a major source of HAP. Therefore, the proposed facility must address potential applicability of Sections 112(g) and 112(j) of the Clean Air Act. Applicability of this subpart and proposed emissions limits, are discussed in Section 6.

4.4.2 40 CFR 63 SUBPART ZZZZ – RECIPROCATING INTERNAL COMBUSTION ENGINES

Subpart ZZZZ regulates hazardous air pollutants (HAP) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. The proposed emergency diesel generators are each rated at 670 brake horse power (bhp) and will not be being tested at a stationary RICE test cell/stand. Therefore, the Subpart ZZZZ applies to the generators.

The emergency generators at the proposed proppant plant will be classified as new emergency compression ignition (CI) (i.e., diesel) engines per 40 CFR §63.6590(a)(2). In accordance with 40 CFR §63.6590(b)(1)(i), new emergency RICE that are greater than 500 horsepower are only subject to the initial notification requirements of 40 CFR §63.6645(f).

In order to be defined as emergency, PyraMax must meet the requirements of 40 CFR §63.6640(f), which contain the hour limitations in NSPS Subpart IIII, as well as the following allowance:

> *You may operate your emergency stationary RICE up to 50 hours per year in non-emergency situations, but those 50 hours are counted towards the 100 hours per year provided for maintenance and testing. The 50 hours per year for non-emergency situations cannot be used for peak shaving or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity; except that owners and operators may operate the emergency engine for a maximum of 15 hours per year as part of a demand response program if the regional transmission organization or equivalent balancing authority and transmission operator has determined there are emergency conditions that could lead to a potential electrical blackout, such as unusually low frequency, equipment overload, capacity or energy deficiency, or unacceptable voltage level. The engine may not be operated for more than 30 minutes prior to the time when the emergency condition is expected to occur, and the engine operation must be terminated immediately after the facility is notified that the emergency condition is no longer imminent. The 15 hours per year of demand response operation are counted as part of the 50 hours of operation per year provided for non-emergency situations. The supply of emergency power to another entity or entities pursuant to financial arrangement is not limited by this paragraph (f)(1)(iii), as long as the power provided by the financial arrangement is limited to emergency power*

The notification requirements in 40 CFR §63.6645(f) are to include the information in 40 CFR §63.9(b)(2)(i) through (v), and a statement that your stationary RICE has no additional requirements and explain the basis of the exclusion. The relevant information is included below:

- *40 CFR §63.9(b)(2)(i) The name and address of the owner or operator;*
- *40 CFR §63.9(b)(2)(ii) The address (i.e., physical location) of the affected source;*
- *40 CFR §63.9(b)(2)(iii) An identification of the relevant standard, or other requirement, that is the basis of the notification and the source's compliance date;*
- *40 CFR §63.9(b)(2)(iv) A brief description of the nature, size, design, and method of operation of the source and an identification of the types of emission points within the affected source subject to the relevant standard and types of hazardous air pollutants emitted; and*
- *40 CFR §63.9(b)(2)(v) A statement of whether the affected source is a major source or an area source.*

The exclusion applies as the proposed engines operate exclusively as emergency stationary RICE that have a site rating of more than 500 brake HP located at a major source of HAP emissions.

4.5 RISK MANAGEMENT PLAN

Subpart B of 40 CFR 68 outlines requirements for risk management prevention plans pursuant to Section 112(r) of the Clean Air Act. Applicability of the subpart is determined based on the type and quantity of chemicals stored at a facility. The facility will exceed the threshold limit for aqueous ammonia.

4.6 COMPLIANCE ASSURANCE MONITORING

Under 40 CFR 64, the Compliance Assurance Monitoring (CAM) regulations, facilities are required to prepare and submit monitoring plans for certain emissions units with the initial or renewal Title V operating permit application. The CAM Plans are intended to provide an on-going and reasonable assurance of compliance with emission limits. Under the general applicability criteria, this regulation only applies to emission units that use a control device to achieve compliance with an emission limit and whose pre-controlled emission levels exceed the major source thresholds under the Title V operating permit program. For a subject unit whose post-controlled emissions also exceed the major source threshold, a CAM plan is required to be submitted with the initial Title V operating permit application. For a subject unit whose post-control emissions are less than the major source threshold, a CAM plan does not have to be submitted until the first renewal application. CAM applicability will be addressed as part of subsequent Title V permit applications.

4.7 GEORGIA RULES FOR AIR QUALITY CONTROL (GRAQC) CHAPTER 391-3-1

In addition to federal air regulations, Georgia Rules for Air Quality Control (GRAQC) Chapter 391-3-1 establishes regulations applicable at the emission unit level (source specific) and at the facility level. The rules also contain requirements related to the need for construction and/or operating permits.

4.7.1 GRAQC 391-3-1-.02(2)(B), VISIBLE EMISSIONS

This regulation limits the opacity from all sources to 40%, provided that the source is subject to some other emission limitation under GRAQC 391-3-1-.02(2).[13] All units at the facility are subject to this rule with the exception of the emergency diesel generators.

4.7.2 GRAQC 391-3-1-.02(2)(D), FUEL-BURNING EQUIPMENT

This regulation limits PM emissions from all fuel-burning equipment less than 10 MMBtu/hr constructed after January 1, 1972 to 0.5 pounds per million BTU heat input. It also limits visible emissions with opacity greater than or equal to 20 percent. This rule is applicable only to the boilers, as the kilns and pelletizers have a higher heat input capacity than 10 MMBtu/hr.

4.7.3 GRAQC 391-3-1-.02(2)(E), PM EMISSIONS FROM MANUFACTURING PROCESSES

This regulation, commonly known as the process weight rule (PWR), establishes PM limits for all sources if not specified elsewhere. The PM emissions are limited based on the following equations (for equipment constructed or modified after July 2, 1968), where equation (a) applies to sources with a process input rate of less than or equal to 30 ton/hr, while equation (b) applies to sources with a process input rate of more than 30 ton/hr:[14]

(a) $E = 4.10 \times P^{0.67}$ (b) $E = 55.0 \times P^{0.11} - 40$

where: E = allowable PM emission rate [lb/hr]
P = process input weight rate [tons/hr]

This rule is not directly applicable to any pieces of equipment at the facility which involve material handling due to the fact that there is a separately established rule for kaolin and fuller's earth process equipment (391-3-1-.02(2)(p)1) to which all material handling sources at the facility are subject.

4.7.4 GRAQC 391-3-1-.02(2)(G), SO_2

This regulation establishes SO_2 emission limits for fuel-burning sources, not "equipment". All fuel burning sources below 100 MMBtu/hr shall not burn fuel containing more than 2.5

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[13] GRAQC 391-3-1-.02(2)(b)1

[14] GRAQC 391-3-1-.02(2)(e)1(i)

percent sulfur, by weight. This requirement is applicable to the kilns, boilers, and pelletizers.

4.7.5 GRAQC 391-3-1-.02(2)(N), FUGITIVE DUST

This regulation requires facilities to take reasonable precautions to prevent fugitive dust from becoming airborne. The proposed facility emission units, such as the shredders, conveyors, and feeders, will be covered by this generally applicable rule. The King's Mill Facility will take the appropriate precautions to prevent fugitive dust from becoming airborne, such as frequent street sweeping, to ensure that the percent opacity is less than 20 percent.

4.7.6 GRAQC 391-3-1-.02(2)(P)1, PARTICULATE EMISSIONS FROM KAOLIN AND FULLER'S EARTH PROCESSES

This regulation establishes PM limits for all kaolin and fuller's earth process equipment. The PM emissions are limited based on the following equations (for equipment constructed or modified after January 1, 1972), where equation (a) applies to sources with a process input rate of less than or equal to 30 ton/hr, while equation (b) applies to sources with a process input rate of more than 30 ton/hr:[15]

(a) $E = 3.59 \times P^{0.62}$ (b) $E = 17.31 \times P^{0.16}$

where: E = allowable PM emission rate [lb/hr]
P = process input weight rate [tons/hr]

All units at the facility with the exception of the boilers and emergency diesel generators are subject to this generally applicable requirement.

4.7.7 GRAQC 391-3-1-.02(2)(BB), PETROLEUM LIQUID STORAGE

This regulation limits the capacity of fixed roof storage vessels containing volatile petroleum liquids with a true vapor pressure greater than 1.52 psia to less than 40,000 gallons. The largest diesel storage tank at the facility is 7,000 gallons, and the diesel fuel used has a vapor pressure less than 1.52 psia. Thus, the petroleum liquid storage tanks at the facility are in compliance with this rule.

4.7.8 GRAQC 391-3-1-.02(2)(UU), VISIBILITY PROTECTION

Rule (uu) requires Georgia EPD to provide an analysis of a proposed major source or a major modification to an existing source's anticipated impact on visibility in any federal Class I area to the appropriate Federal Land Manager (FLM). An analysis of federal Class I areas resulted in a Q/d value less than 10.[16] Therefore, a full review of the anticipated impact on visibility was not performed.

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[15] GRAQC 391-3-1-.02(2)(p)1(i) and (ii)

[16] Additionally, based on the October 2010 guidance from the Federal Land Managers' (FLM Air Quality Related Values Work Group (FLAG), FLAG Phase I Report – Revised, October 28, 2010), detailed Air Quality Related Values

4.7.9 GRAQC 391-3-1-.02(2)(RRR), NO_X FROM SMALL FUEL-BURNING EQUIPMENT

Rule (rrr) specifies requirements for fuel-burning equipment with capacities of less than 100 MMBtu/hr installed before May 1, 1999, or units with capacities less than 10 MMBtu/hr installed after May 1, 1999 located in or near the original Atlanta 1-hour ozone nonattainment area. Although the boilers are less than 10 MMBtu/hr, the Jefferson County (Wrens, GA) area where this facility will be located is not within the geographic area covered by this rule.

4.7.10 GRAQC 391-3-1-.03(1), CONSTRUCTION PERMITTING

The proposed project is a greenfield facility and will require physical construction activities to allow construction of all buildings, roads, and equipment. Emissions increases associated with the proposed project are above the *de minimis* construction permitting thresholds specified in GRAQC 391-3-1-.03(6)(i).[17] Further, PSD permitting is required for CO, VOC, $PM/PM_{10}/PM_{2.5}$, SO_2, NO_x, and GHG. Therefore, a construction permit application is necessary and has been completed for the facility.

4.7.11 GRAQC 391-3-1-.03(6)(B)(V)(11)(1), COMBUSTION EQUIPMENT EXEMPTIONS

This regulation waives the requirement for SIP permits for fuel-burning equipment having a total heat capacity of less than 10 MMBtu/hr burning only natural gas, LPG, and/or distillate fuel oil containing 0.50 percent sulfur by weight or less. This rule would potentially apply to the emergency diesel generators and boilers at the facility. Documentation regarding these emission sources has been included within this application.

4.7.12 GRAQC 391-3-1-.03(10), TITLE V OPERATING PERMITS

The facility will be a major source, which will require operation under a Title V Operating Permit. A Title V Application will be submitted within twelve months of commencement of operation of the source, as required by 40 CFR Part 70.5. The facility shall address potential 40 CFR Part 64 Compliance Assurance Monitoring (CAM) applicability in its initial Title V Operating Permit application.

(AQRV) modeling for visibility and deposition is not required for facilities located more than 50 km from the nearest Class I area and have a Q/d value of less than 10 [where Q is the sum of the short-term, daily maximum NO_X, PM_{10}, and SO_2, and H_2SO_4 project emission increases (expressed in tpy) and d is the distance to the Class I area (expressed in kilometers)]. This Q/d screening threshold was proposed since it is consistent with what was utilized by U.S. EPA in their 2005 Best Available Retrofit Technology (BART) guidelines. Using the project increases, Q/D results were less than 10. Please see Volume II for additional information regarding the Q/D analysis.

[17] Based on Georgia EPD guidance, usage of the *de minimis* permitting exemption thresholds must consider actual-to-potential emissions increases, not actual-to-projected actual emissions increases.

4.7.13 GRAQC 391-3-1-.02(2)(LLL), NO_X FROM FUEL-BURNING EQUIPMENT S

Rule (lll) limits NO_X emissions from fuel-burning equipment with capacities between 10 and 250 MMBtu/hr that are located in or near the original Atlanta 1-hour ozone nonattainment area. Although the facility will have fuel-burning equipment between 10 and 250 MMBtu/hr, the Jefferson County (Wrens, GA) area where this facility will be located is not within the geographic area covered by this rule.

4.7.14 INCORPORATION OF FEDERAL REGULATIONS BY REFERENCE

The following federal regulations are incorporated in the GRAQC by reference, and were addressed in the Federal Regulatory review in Section ___ of this application:

- GRAQC 391-3-1-.02(7) – PSD
- GRAQC 391-3-1-.02(8) – NSPS
- GRAQC 391-3-1-.02(9) – NESHAP
- GRAQC 391-3-1-02(11) – CAM

5. BACT ANALYSIS

This section discusses the regulatory basis for BACT, approach used in completing the BACT analyses, and the BACT analyses for the proposed facility and all associated equipment. Supporting documentation is included in Appendix D.

5.1 BACT DEFINITION

The requirement to conduct a BACT analysis is set forth in the PSD regulations [40 CFR 52.21(j)(2)]:

> *(j) Control Technology Review.*
>
> *(2) A new major stationary source shall apply best available control technology for each regulated NSR pollutant that it would have the potential to emit in significant amounts.*

BACT is defined in the PSD regulations [40 CFR 52.21(b)(12)] as:

> *...an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61.*
> [primary BACT definition]
>
> *If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.*
> [allowance for secondary BACT standard under certain conditions]

The primary BACT definition can be best understood by breaking it apart into its separate components.

5.1.1 EMISSION LIMITATION

an emissions limitation

First and foremost, BACT is an emission limit. While BACT is prefaced upon the application of technologies to achieve that limit, the final result of BACT is a limit. In general, this limit would be an emission rate limit of a pollutant (i.e., lb/MMBtu).[18]

5.1.2 CASE-BY-CASE BASIS

a case-by-case basis, taking into account energy, environmental and economic impacts and other costs

Unlike many of the Clean Air Act programs, the PSD program's BACT evaluation is case-by-case. As noted by U.S. EPA,

> *The case-by-case analysis is far more complex than merely pointing to a lower emissions limit or higher control efficiency elsewhere in a permit or a permit application. The BACT determination must take into account all of the factors affecting the facility, such as the choice of [fuel]… The BACT analysis, therefore, involves judgment and balancing.*[19]

To assist applicants and regulators with the case-by-case process, in 1987 U.S. EPA issued a memorandum that implemented certain program initiatives to improve the effectiveness of the PSD program within the confines of existing regulations and state implementation plans.[20] Among the initiatives was a "top-down" approach for determining BACT. In brief, the top-down process suggests that all available control technologies be ranked in descending order of control effectiveness. The most stringent or "top" control option is the default BACT emission limit unless the applicant demonstrates, and the permitting authority in its informed opinion agrees, that energy, environmental, and/or economic impacts justify the conclusion that the most stringent control option is not achievable in that case. Upon elimination of the most stringent control option based upon energy, environmental, and/or economic considerations, the next most stringent alternative is evaluated in the same manner. This process continues until BACT is selected.

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[18] Emission limits can be broadly differentiated as "rate-based" or "mass-based." For a kiln, a rate-based limit would typically be in units of lb/ton (mass emissions per ton material input). In contrast, a typical mass-based limit would be in units of lb/hr (mass emissions per time).

[19] U.S. EPA Responses to Public Comments on the Proposed PSD Permit for the Desert Rock Energy Facility, July 31, 2008, p.41-42.

[20] Memo dated December 1, 1987, from J. Craig Potter (EPA Headquarters) to EPA Regional Administrators, titled "Improving New Source Review Implementation."

The five steps in a top-down BACT evaluation can be summarized as follows:

Step 1. Identify all possible control technologies;

Step 2. Eliminate technically infeasible options;

Step 3. Rank the technically feasible control technologies based upon emission reduction potential;

Step 4. Evaluate ranked controls based on energy, environmental, and/or economic considerations; and

Step 5. Select BACT.

While the top-down BACT analysis is a procedural approach suggested by U.S. EPA policy, [21] this approach is not specifically mandated as a statutory requirement of the BACT determination. As discussed in Section 6.1.1, the BACT limit is an emissions limitation and does not require the installation of any specific control device.

5.1.3 ACHIEVABLE

based on the maximum degree of reduction ...[that Georgia EPD] … *determines is achievable ... through application of production processes or available methods, systems and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques*

BACT is to be set at the lowest value that is achievable. However, there is an important distinction between emission rates achieved at a specific time on a specific unit, and an emission limitation that a unit must be able to meet continuously over its operating life.

As discussed by the DC Circuit Court of Appeals,

> *In National Lime Ass'n v. EPA, 627 F.2d 416, 431 n.46 (D.C. Cir. 1980), we said that where a statute requires that a standard be "achievable," it must be achievable "under most adverse circumstances which can reasonably be expected to recur."*[22]

U.S. EPA has reached similar conclusions in prior determinations for PSD permits.

> *Agency guidance and our prior decisions recognize a distinction between, on the one hand, measured 'emissions rates,' which are necessarily data obtained from a particular facility at a specific time, and on the other hand, the 'emissions limitation' determined to be BACT and set forth in the permit, which the facility is required to continuously meet throughout the facility's life. Stated simply, if there is uncontrollable fluctuation or variability in the measured emission rate, then the*

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[21] In November 2010, the U.S. EPA issued a guidance document for the permitting of GHGs that recommends that permitting authorities use the same top-down BACT process to determine BACT for GHGs. U.S. EPA Office of Air and Radiation, Office of Air Quality Planning and Standards, *PSD and Title V Permitting Guidance for Greenhouse Gases, November 2010*,page 18, http://www.epa.gov/nsr/ghgdocs/epa-hq-oar-2010-0841-0001.pdf,

[22] As quoted in Sierra Club v. EPA (97-1686).

> *lowest measured emission rate will necessarily be more stringent than the "emissions limitation" that is "achievable" for that pollution control method over the life of the facility. Accordingly, because the "emissions limitation" is applicable for the facility's life, it is wholly appropriate for the permit issuer to consider, as part of the BACT analysis, the extent to which the available data demonstrate whether the emissions rate at issue has been achieved by other facilities over a long term.* [23]

Thus, BACT must be set at the lowest feasible emission rate recognizing that the emission unit must be in compliance with that limit for the lifetime of the unit on a continuous basis. Thus, while viewing individual unit performance can be instructive in evaluating what BACT might be, any actual performance data must be viewed carefully, as rarely will the data be adequate to truly assess the performance that a unit will achieve during its entire operating life. While statistical variability of actual performance can be used to infer what is "achievable," such testing requires a detailed test plan akin to what teams in U.S. EPA use to develop MACT standards over a several year period, and is far beyond what is reasonable to expect of an individual source. In contrast to limited snapshots of actual performance data, emission limits from similar sources can reasonably be used to infer what is "achievable."[24]

To assist in meeting the BACT limit, the source must consider production processes or available methods, systems or techniques, as long as those considerations do not redefine the source (see Section 6.2).

5.1.4 FLOOR

Emissions [shall not] *exceed …40 CFR Parts 60 and 61*

The least stringent emission rate allowable for BACT is any applicable limit under either New Source Performance Standards (NSPS – Part 60) or National Emission Standards for Hazardous Air Pollutants (NESHAP – Parts 61 and 63). State SIP limitations must also be considered when determining the floor.

5.2 REDEFINING THE SOURCE

Historical practice, as well as recent court rulings, has been clear that a key foundation of the BACT process is that BACT applies to the type of source proposed by the applicant, and that redefining the source is not appropriate in a BACT determination.

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[23] U.S. EPA Environmental Appeals Board decision, *In re: Newmont Nevada Energy Investment L.L.C.* PSD Appeal No. 05-04, decided December 21, 2005. Environmental Administrative Decisions, Volume 12, Page 442.

[24] Emission limits must be used with care in assessing what is "achievable." Limits established for facilities which were never built must be viewed with care, as they have never been demonstrated and that company never took a significant liability in having to meet that limit. Likewise, permitted units which have not yet commenced construction must also be viewed with special care for similar reasons.

Though BACT is based on the type of source as proposed by the applicant, the scope of the applicant's ability to define the source is not absolute. As U.S. EPA notes, a key task for the reviewing agency is to determine which parts of the proposed process are inherent to the applicant's purpose and which parts may be changed without changing that purpose. As discussed by U.S. EPA in an opinion on the Prairie State project,

> *We find it significant that all parties here, including Petitioners, agree that Congress intended the permit applicant to have the prerogative to define certain aspects of the proposed facility that may not be redesigned through application of BACT and that other aspects must remain open to redesign through application of BACT.*[25]
>
> …
>
> *When the Administrator first developed* [U.S. EPA's policy against redefining the source] *in* Pennsauken*, the Administrator concluded that permit conditions defining the emissions control systems "are imposed on the source as the applicant has defined it" and that "the source itself is not a condition of the permit."*[26]

Given that some parts of the project are not open for review under BACT, U.S. EPA then discusses that it is the permit reviewer's burden to define the boundary. Based on precedent set in multiple prior U.S. EPA rulings (e.g., Pennsauken County Resource Recovery [1988], Old Dominion Electric Coop [1992], Spokane Regional Waste to Energy [1989], U.S. EPA states the following in Prairie State:

> *For these reasons, we conclude that the permit issuer appropriately looks to how the applicant, in proposing the facility, defines the goals, objectives, purpose, or basic design for the proposed facility. Thus, the permit issuer must be mindful that BACT, in most cases, should not be applied to regulate the applicant's objective or purpose for the proposed facility, and therefore, the permit issuer must discern which design elements are inherent to that purpose, articulated for reasons independent of air quality permitting, and which design elements may be changed to achieve pollutant emissions reductions without disrupting the applicant's basic business purpose for the proposed facility.* [27]

U.S. EPA's opinion in Prairie State was upheld on appeal to the Seventh Circuit Court of Appeals, where the court affirmed the substantial deference due the permitting authority on defining the demarcation point.[28]

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[25] U.S. EPA Environmental Appeals Board decision, *In re: Prairie State Generating Company*. PSD Appeal No. 05-05, decided August 24, 2006, Page 26.

[26] U.S. EPA Environmental Appeals Board decision, *In re: Prairie State Generating Company*. PSD Appeal No. 05-05, decided August 24, 2006, Page 29.

[27] U.S. EPA Environmental Appeals Board decision, *In re: Prairie State Generating Company*. PSD Appeal No. 05-05, decided August 24, 2006, Page 30.

[28] *Sierra Club v. EPA and Prairie State Generating Company LLC*, Seventh Circuit Court of Appeals, No. 06-3907, August 24, 2007. Rehearing denied October 11, 2007, 499 F.3d 653 (7th Cir. 2007).

Taken as a whole, the permitting agency is tasked with determining which controls are appropriate, but the discretion of the agency does not extend to a point requiring the applicant to redefine the source.

PyraMax plans to construct a greenfield proppant facility for the production of proppant beads for use in the oil and gas industry. The major raw material is clay. The clay is mixed with chemicals and then fired in a kiln process to produce ceramic beads. Expected emissions from the facility are NO_X, CO, PM, PM_{10}, $PM_{2.5}$, SO_2, VOC, GHG and combustion emissions associated with natural gas and propane combustion. Additionally, hydrogen fluoride (HF), hydrogen chloride (HCl), and methanol will be emitted from the process either due to the presence in the raw material (HF and HCl) or as an impurity in the chemicals added (methanol).

Specific equipment that will be used as part of the facility processes will include raw material and product handling equipment, pelletizers used to produce rough proppant beads, calcining/sintering kilns used to produce final product, boilers used to produce steam, and emergency generators present to provide emergency power if needed. The primary fuel to be used at the facility for facility combustion sources (with the exception of the emergency generator) will be natural gas with propane fuel used as a backup.

5.3 BACT REQUIREMENT

The BACT requirement applies to each new or modified emission unit from which there are emissions increases of pollutants subject to PSD review. The proposed project is subject to PSD permitting for NO_X, CO, VOC, $PM/PM_{10}/PM_{2.5}$, SO_2 and GHG, and thus, subject to BACT for these pollutants. The kilns, pelletizers, boilers, and emergency generators are subject to BACT for each pollutant requiring PSD permitting that is emitted by the particular piece of equipment, while the material handling and processing equipment are subject to BACT only for $PM/PM_{10}/PM_{2.5}$. The following emission units and pollutants were considered in the BACT analysis and detailed discussions of each unit are included in the sections below :

- Ceramic Kiln: NO_X, SO_2, PM, PM_{10}, $PM_{2.5}$, CO, VOC
- Emergency Diesel Generator: NO_X, SO_2, PM, PM_{10}, $PM_{2.5}$, CO, VOC
- Natural Gas Boiler: NO_X, SO_2, PM, PM_{10}, $PM_{2.5}$, CO, VOC
- Pelletizer: NO_X, SO_2, PM, PM_{10}, $PM_{2.5}$, CO, VOC
- Material Handling and Processing Equipment (both raw material and product) : PM, PM_{10}, $PM_{2.5}$

Note the same control techniques that reduce PM also reduce filterable PM_{10} and $PM_{2.5}$. The PM_{10} BACT analyses will satisfy BACT for PM and $PM_{2.5}$. In the prepared BACT analyses, references to PM_{10} are also relevant for PM and $PM_{2.5}$, and neither PM nor $PM_{2.5}$ are explicitly addressed separately.

5.4 BACT ASSESSMENT METHODOLOGY

The following sections provide detail on the BACT assessment methodology utilized in preparing the BACT analysis for the proposed facility. As previously noted, the minimum control efficiency to be considered in a BACT assessment must result in an emission rate less than or equal to any applicable NSPS or NESHAP emission rate for the source. The following NSPS or NESHAP emission limits will apply to proposed equipment and effectively set the floor for BACT for these units for certain pollutants:

- Kiln:
  - 10% Visible Emissions (NSPS Subpart UUU)
  - PM limit of 0.040 gr/dscf (NSPS Subpart UUU)
- Emergency Diesel Generator:
  - PM limit of 0.2 g/kW-hr NO_X (NSPS Subpart IIII)
  - NMHC limit of 4 g/kW-hr (NSPS Subpart IIII)
- Pelletizer:
  - PM limit of 0.040 gr/dscf (NSPS Subpart UUU) for calciners and dryers installed in series

- PM limit of 0.025 gr/dscf (NSPS Subpart UUU) for dryers

- Material Handling and Processing Equipment:
  PM limit of 0.014 gr/dscf (NSPS Subpart OOO)

5.4.1 IDENTIFICATION OF POTENTIAL CONTROL TECHNOLOGIES

Potentially applicable emission control technologies were identified by researching the U.S. EPA control technology database, technical literature, control equipment vendor information, state permitting authority files, and by using process knowledge and engineering experience. The Reasonably Available Control Technology (RACT)/BACT/Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC), a database made available to the public through the U.S. EPA's Office of Air Quality Planning and Standards (OAQPS) Technology Transfer Network (TTN), lists technologies and corresponding emission limits that have been approved by regulatory agencies in permit actions. These technologies are grouped into categories by industry and can be referenced in determining what emissions levels were proposed for similar types of emissions units.

Trinity performed searches of the RBLC database in June 2011 to start identifying the emission control technologies and emission levels that were determined by permitting authorities as BACT within the past ten years for emission sources comparable to the proposed facility. The following categories were searched:

- Cement Manufacturing (RBLC Code 90.006)
- Clay and Fly Ash Sintering (RBLC Code 90.008)
- Clay Products including Bricks & Ceramics (RBLC Code 90.009)
- Calciners & Dryers and Mineral Processing Facilities (RBLC Code 90.017)

- Lime/Limestone Handling/Kilns/Storage/Manufacturing (RBLC Code 90.019)
- Non-metallic Mineral Processing (RBLC Code 90.024)
- Portland Cement Manufacturing (RBLC Code 90.028)
- Other Mineral Processing Sources (RBLC Code 90.999)
- Fugitive Dust Sources (RBLC Code 99.100)
- Other Miscellaneous Sources (RBLC Code 99.999)
- Commercial/Institutional-Size Boilers/Furnaces (<100 MMBtu/hr) – Gaseous Fuel & Gaseous Fuel Mixtures (RBLC Code 13.300)
- Commercial/Institutional-Size Boilers/Furnaces (<100 MMBtu/hr) – Natural Gas (includes propane and liquefied petroleum gas) (RBLC Code 13.310)
- Large Internal Combustion Engines (>500 hp) (RBLC Code 17.100)
- Large Internal Combustion Engines burning fuel oil (RBLC Code 17.110)

Upon completion of the RBLC search, Trinity then reviewed relevant vendor information, pending permit applications, and issued permits not included in the RBLC. Appendix D presents a summary table of relevant BACT determinations for the units mentioned above.

As noted previously, no other units are subject to BACT review. Therefore, no additional RBLC searches or other technical reviews were performed.

5.4.2 ECONOMIC FEASIBILITY CALCULATION PROCESS

Economic analyses were performed to compare total costs (capital and annual) for potential control technologies. Capital costs include the initial cost of the components intrinsic to the complete control system. Annual operating costs include the financial requirements to operate the control system on an annual basis and include overhead, maintenance, outages, raw materials, and utilities.

The capital cost estimating technique used is based on a factored method of determining direct and indirect installation costs. That is, installation costs are expressed as a function of known equipment costs. This method is consistent with the latest U.S. EPA OAQPS guidance manual on estimating control technology costs.[29]

Total Purchased Equipment Cost represents the delivered cost of the control equipment, auxiliary equipment, and instrumentation. Auxiliary equipment consists of all the structural, mechanical, and electrical components required for the efficient operation of the device. Auxiliary equipment costs are estimated as a straight percentage of the equipment cost. Direct installation costs consist of the direct expenditures for materials and labor for

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[29] U.S. EPA, *OAQPS Control Cost Manual*, 6th edition, EPA 452/B-02-001, July 2002. http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf

site preparation, foundations, structural steel, erection, piping, electrical, painting and facilities. Indirect installation costs include engineering and supervision of contractors, construction and field expenses, construction fees, and contingencies. Other indirect costs include equipment startup, performance testing, working capital, and interest during construction.

Annual costs are comprised of direct and indirect operating costs. Direct annual costs include labor, maintenance, replacement parts, raw materials, utilities, and waste disposal. Indirect operating costs include plant overhead, taxes, insurance, general administration, and capital charges. Replacement part costs, such as the cost of replacement bags for a baghouse, were included where applicable, while raw material costs were estimated based upon the unit cost and annual consumption. With the exception of overhead, indirect operating costs were calculated as a percentage of the total capital costs. The indirect capital costs were based on the capital recovery factor (CRF) defined as:

$$CRF = \frac{i(1+i)^n}{(1+i)^n - 1}$$

where *i* is the annual interest rate and *n* is the equipment life in years. The equipment life is based on the normal life of the control equipment and varies on an equipment type basis. The same interest applies to all control equipment cost calculations. For this analysis, an interest rate of 7% was used based on information provided in the most recent OAQPS Control Cost Manual.[30]

Note that all economic calculations are based on May, 2011 dollars. Detailed cost analyses calculations for economic analyses presented within this BACT analysis are presented in Appendix D.

5.4.3 SELECTED BACT SUMMARY

Table 5-1 below lists the selected best available control technology per emission unit and pollutant, the corresponding emission or operating limits, and the method that will be used to determine compliance with the specified limit.

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[30] U.S. EPA, *OAQPS Control Cost Manual*, 6th edition, Section 2, Chapter 1, page 1-52. http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf

TABLE 5-1. SELECTED BACT SUMMARY

Unit	Pollutant	Selected BACT	Emission/ Operating Limit	Compliance Method
Ceramic Kiln	NO_X	Catalytic Baghouse System	36.3 lb/hr	Method 7 or 7E
	SO_2	Catalytic Baghouse System	11.64 lb/hr	Method 6 or 6C
	CO	Good Combustion Practices	51.36 lb/hr	Method 10
	PM/PM_{10} + CPM[1]	Catalytic Baghouse System	8.53 lb/hr	Method 201/201A, 202
	$PM_{2.5}$ + CPM[1]	Catalytic Baghouse System	6.98 lb/hr	Method 201/201A, 202
	VOC	Good Combustion Practices	0.54 lb/hr	Method 25A
Pelletizer	NO_X	Good Design/Combustion Practices, Low NO_X burners	2.25 lb/hr	Method 7 or 7E
	SO_2	Burning Clean Fuels (Natural Gas/Propane)	None	Type/amount fuel records
	CO	Good Combustion Practices	13.73 lb/hr	Method 10
	PM/PM_{10} (filterable)	Baghouse	0.01 gr/dscf	Method 201/201A, 202
	$PM_{2.5}$ (filterable)	Baghouse	0.006 gr/dscf	Method 201/201A, 202
	VOC	Good Combustion Practices	11.78 lb/hr	Kiln Feed Mass Balance/ MSDS
Boiler	NO_X	Good Design/Combustion Practices, Low NO_X burners	None	Type/amount fuel records
	SO_2	Burning Clean Fuels (Natural Gas/Propane)	None	Type/amount fuel records
	CO	Good Combustion Practices	None	Type/amount fuel records
	$PM/PM_{10}/PM_{2.5}$	Burning Clean Fuels (Natural Gas/Propane)	None	Type/amount fuel records
	VOC	Good Combustion Practices	None	Type/amount fuel records
Emergency Generator	NO_X	NSPS Subpart IIII	4 g/kW-hr	Vendor Guarantee
	SO_2	Burning Clean Fuels (Natural Gas/Propane)	15 ppm sulfur content	Type/amount fuel records
	CO	NSPS Subpart IIII	3.5 g/kW-hr	Vendor Guarantee
	$PM/PM_{10}/PM_{2.5}$	Burning Clean Fuels (Natural Gas/Propane)	100 hours/yr	Type/amount fuel records
	VOC	Burning Clean Fuels (Natural Gas/Propane)	100 hours/yr	Type/amount fuel records
Material Handling	$PM/PM_{10}/PM_{2.5}$	Baghouses on point sources	0.005 gr/dscf	Vendor Guarantee

1. Condensable Particulate Matter

5.5 CALCINING KILN - NO_X BACT

5.5.1 BACKGROUND ON POLLUTANT FORMATION

The kilns are direct fired and combust natural gas with propane as a backup. NO_X emissions from calcining kilns are primarily due to thermal NO_X generation as well as some NO_X formation from nitrogen content of the clay materials, as well as some amount of NO_X from fuel combustion (i.e. natural gas). NO_X formed in the high-temperature, post-flame region of the combustion equipment is "thermal NO_X." Temperature is the most important factor, and at higher flame temperatures that are typical in the kiln burning zone, thermal NO_X formation increases exponentially. Temperatures within the kiln system can exceed 3,000 ^oF.

5.5.2 IDENTIFICATION OF POTENTIAL CONTROL TECHNIQUES (STEP 1)

Candidate control options identified from the RBLC search and the literature review include those classified as pollution reduction techniques. NO_X reduction options include:

- Catalytic Baghouse System (for multi-pollutant control)
- Selective Non-Catalytic Reduction (SNCR)
- Selective Catalytic Reduction (SCR)
- Regenerative Selective Catalytic Reduction (RSCR)
- Good Design and Operating Practices such as low NO_X burners/combustion control

These control technologies are briefly discussed in the following sections. [31]

5.5.2.1 CATALYTIC BAGHOUSE SYSTEM

The Catalytic Baghouse System incorporates catalyst filter for NO_X removal where nanobits of SCR catalyst are embedded in the walls of the filter elements. Urea or ammonia is injected upstream of the filters and the catalyst embedded in the filters converts NO_X with a high removal efficiency (up to 95% possible based on vendor data) at lower temperatures (350 to 400 ºF). Such systems can be used in streams with high particulate loading since the catalyst will not be plugged by the particulate due to removal of particulate at the same time as removal of NO_X.

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[31] Documentation reviewed in recent permitting action for the Carbo Ceramics, Inc. Toomsboro and McIntyre facilities (Application No. 18293, 18304) revealed review and discussions regarding water scrubbing for control of NOx emissions. Review of permitting documentation for these facilities revealed that use of the control technology, and information regarding its use, was based on investigations of its use at their particular facilities through consultation with a vendor, and studies undertaken on Carbo's existing facility operations, which did not yield reported results of 90% NOx control with this technology as reported in application documentation (letter dated 11/30/09 from Carbo Ceramics, Inc. to F. Allen Barnes, GA EPD indicating 14-50% NOx control). Therefore, with a lack of information regarding its effective use on similar units, and the fact that this technology was determined infeasible and cost ineffective for the Carbo Ceramics, Inc. facilities it has not been addressed within this application.

5.5.2.2 SELECTIVE NON-CATALYTIC REDUCTION

SNCR is an exhaust gas treatment process in which urea or ammonia is injected into the exhaust gas. The effectiveness of SNCR systems depends on several factors, including CO and SO_2 flue gas concentrations, flue gas temperature, residence time, and reagent and flue gas mixing. If high CO concentrations are present, then the reagent efficiency is decreased, and if high SO_2 concentrations are present, then the temperature for optimal performance is increased. Per SNCR vendor documentation, high temperatures, normally between 1,550 and 2,000°F, are necessary to promote the reaction between urea or ammonia (NH_3) and NO_X to form N_2 and water.

Outside of the design temperature window, the emissions are adversely affected. If the temperatures are too high, then the reagent may be oxidized, causing additional NO_X emissions. If the temperatures are too low, then the reaction between the reagent and NO_X is slowed, and emissions of the reagent will be present. A sufficient residence time and reagent mixing time are also necessary to ensure maximum NO_X reductions are achieved and no excess emissions of the reagent are present.[32] Typical removal efficiencies for SNCR applied in conjunction with low NO_X burners range from 65 to 75 percent.[33]

5.5.2.3 SELECTIVE CATALYTIC REDUCTION

Selective catalytic reduction (SCR) is an exhaust gas treatment process in which ammonia or urea is injected into the exhaust gas upstream of a catalyst. The ammonia or urea reacts to form nitrogen (N_2) and water on the surface of the catalyst, which typically has a temperature between 450 and 850° F. When operated within the optimum temperature range, the reaction can result in removal efficiencies between 70 and 90 percent.[34]

In the SCR process, urea or ammonia, stored either as an anhydrous ammonia or aqueous solution, is injected into the exhaust upstream of the catalyst. The exhaust/ammonia (or urea) mixture passes over the catalyst, which lowers the activation energy of the NO decomposition reaction, therefore, lowering the temperature necessary to carry out the reaction.

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[32] Kitto, J.B. *Air Pollution Control For Industrial Boiler Systems.* Barberton, OH: Babcock & Wilcox. November 1996. http://www.babcock.com/library/pdf/BR-1624.pdf

[33] Per U.S. EPA Clean Air Technology Center, Air Pollution Control Technology Fact Sheet for SNCR. http://www.epa.gov/ttn/catc/dir1/fsncr.pdf.

[34] U.S. EPA, Office of Air Quality Planning and Standards. *OAQPS Control Cost Manual Section 4-2 Chapter 2,* 6th edition. EPA 452/B-02-001. Research Triangle Park, NC. January 2002.

5.5.2.4 REGENERATIVE SELECTIVE CATALYTIC REDUCTION (RSCR)

On the cold side of the exhaust, there is a relatively limited amount of particulates and chemicals present in the flue gas, which limits the damage and degradation of the catalysts used in the system. However, the flue gas temperature is much less than the temperature range required for the successful reaction between the ammonia or urea injections with the NO_X of the flue gas. For this reason, the flue gas is temporarily reheated to a temperature in which NO_X successfully reacts with the ammonia or urea injections.

To minimize fuel consumption, the heating of the flue gas is accomplished using the "regenerative" heating technology, in a system analogous to a regenerative thermal oxidizer (RTO) as might be used to control an organics stream.[35] In the regenerative selective catalytic reduction (RSCR) configuration, the reagent is first introduced upstream of the RSCR unit. The flue gas/reagent mixture (previously cleaned of particulate matter) then enters one end of the system, where the flue gas mixture travels up through the (hot) ceramic heat retention canister to be reheated. The flue gas mixture then flows through the catalyst section, where the ammonia reacts with the NO_X to form nitrogen and water. After the catalyst, the flue gas flows through a "retention" chamber, where a burner reheats the flue gas slightly. From this chamber, the flue gas then flows through the (cold) second canister and is used to heat this canister's ceramic heat retention block. Once this cycle is complete, the air flow is diverted, so that the second canister is the inlet for the "cold" flue gas, and the first canister is the outlet for the cleaned flue gas. The RSCR approach minimizes the supplemental fuel required to reheat the cold exhaust gas. A control efficiency of greater than 80 percent could be expected from a control device such as the RSCR.[36]

5.5.2.5 GOOD DESIGN AND OPERATING PRACTICES

NO_X formation can be most cost-effectively minimized by proper operation and design practices. Operators can control the localized peak combustion temperature and combustion stoichiometry to minimize NO_X formation while achieving efficient fuel combustion. NO_X emissions are reduced by limiting the amount of excess air, but other pollutant emissions are limited by complete combustion. Incomplete combustion in the kiln could contribute to excess amounts of CO emissions. Use of Low NO_X burners is a typical common design practice at this time for design minimization of combustion formed NO_X emissions.

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[35] In contrast, a traditional cold-side SCR would use a Ljungstrom-style air heater to reheat the flue gas at a much greater energy penalty.

[36] http://www.babcockpower.com/pdf/bpe-04.pdf and http://www.oneonta.ny.us/pdf/RSCROvrw.pdf

5.5.3 ELIMINATION OF TECHNICALLY INFEASIBLE CONTROL OPTIONS (STEP 2)

After the identification of control options, the second step in the BACT assessment is to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that would prohibit the implementation of the control or if the highest control efficiency of the option would result in an emission level that is higher than any applicable regulatory limits. All previously identified control technologies are technically feasible, with the exception of the RSCR system.

The Carbo Ceramics, Inc. Toomsboro Georgia facility conducted extensive research regarding the use of RSCR technology for the control of NO_X emissions from the facility kilns, as well as other facility emission units.[37] Documentation submitted by Carbo Ceramics, Inc. indicated concerns with application of the RSCR technology as it was still considered experimental for control of NO_X emissions in similar applications, and raised concerns regarding fouling and plugging of the system catalyst. Additional research conducted could find no instances of the application of RSCR technology on a comparable kiln system as to be installed at the PyraMax facility.

5.5.4 RANK OF REMAINING CONTROL TECHNOLOGIES (STEP 3)

The third of the five steps in the top-down BACT assessment procedure is to rank technically feasible control technologies by control effectiveness. The remaining control technologies are presented in Table 5-2.

TABLE 5-2. REMAINING NO_X CONTROL TECHNOLOGIES

Rank	Control Technology	Potential Control Efficiency (%)
1	Catalytic Baghouse System	up to 95%
2	SCR	70-90%
4	SNCR	65-75%
5	Good Combustion Practices	Base Case

5.5.5 EVALUATION OF MOST STRINGENT CONTROLS (STEP 4)

The fourth of the five steps in the top-down BACT assessment procedure is to evaluate the most effective control and document the results.

The highest ranked technology, the Catalytic Baghouse system, achieves NO_X control in the presence of a catalyst by reacting ammonia and NO_X to form nitrogen and water. This system, based on vendor data, has the potential to achieve a control efficiency of 95% when operated in the specified temperature range. However, what is important to note is

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[37] Application No. 18293, Letter Dated February 9, 2009 from Carbo Ceramics, Inc. to Mr. Jac Capp of the Georgia EPD

that no reference could be found of such a system ever being installed for control of NO_X emissions on a ceramic proppant kiln.

No significant environmental impacts are expected from the operation of the system. Additional heat to reheat the flue gas is not required since temperatures as low as 350 ºF are sufficient for the required control thereby reducing energy demand. Also, there are no significant waste material or waste products anticipated related to control of NO_X emissions from the kilns.

As such, PyraMax has determined that the Catalytic Baghouse system is BACT since it has both the potential to achieve a high reduction in NO_X emissions, and will also effectively serve in control of both $PM/PM_{10}/PM_{2.5}$ and SO_2 emissions as described further within the BACT analysis. The system will not have projected prohibitive environmental or energy impacts. Since this system is part of an integrated baghouse system, the historic concerns regarding fouling and plugging associated with control of NO_X for SCR systems should not be a concern, as the specific NO_X catalyst is embedded within the filter bags of the system themselves.

Vendor information supplied for the Catalytic Baghouse system has indicated that it will be a cost effective control technology with control costs of well under $10,000/ton of pollutant controlled. Control technologies ranked lower than the Catalytic Baghouse system were not further evaluated.

5.5.6 SELECTION OF BACT (STEP 5)

Based on the previous analyses, PyraMax has determined that the Catalytic Baghouse system is the appropriate BACT control technology for the proposed kiln system, which includes an integral kiln cooler. The integral kiln cooler is not a source of combustion related emissions. Low NO_X burners will also be used within the kiln system for minimization of combustion related NO_X emissions.

As seen from Table D-1, NO_X emission rates for kiln systems researched vary based on a few major factors. Primarily, the amount of NO_X emissions is inversely related to the amount of CO emissions. This is due to the basic principles of NO_X and CO formation in combustion. In general, incomplete combustion leads to increased CO formation, while any amount of excess oxygen, which is needed for complete combustion, allows for the fuel-bound nitrogen to react with the oxygen to form fuel NO_X.

In reviewing Table D-1, a number of the most stringent limits are for kilns employing good combustion techniques with low NO_X burners. In addition, coal fired kilns employed SNCRs. Any natural gas kilns identified employed SCRs, which are similar to the Catalytic Baghouse system with the exception of the operating temperature at which conversion of NO_X is observed. A review of possible similar sources from the RBLC database indicated a wide variety of emission limits established for BACT, with some being heat input limit based (lb/MMBtu), material input based (lb/ton material processed), and weight based per mass of emissions (lb/hr, ton/yr). As such, it is difficult to make direct comparisons to many of the RBLC and permit information documentation found for the sources identified.

However, there are a limited amount of facilities conducting the same type of operations and producing the same products as planned by the PyraMax facilities. The most comparable facilities would be the Carbo Ceramics, Inc. Toomsboro and McIntyre facilities located in Georgia. These sources are currently uncontrolled for NO_X emissions, with emission limits from each kiln at the Toomsboro facility limited to 121 lb/hr, and at the McIntyre facility to 82 lb/hr.

Uncontrolled emission estimates for NO_X emissions are provided in Appendix C. Based on an uncontrolled NO_X emission rate estimate of 7.8 lb uncontrolled NO_X per ton material processed, and an estimated control efficiency of 80%, BACT is proposed as an emission limit of 36.3 lb/hr, with compliance demonstrated per period stack testing per EPA Method 7 or 7E, or other methodologies as may be approved by the Division.[38] The selected BACT control technology is use of a Catalytic Baghouse system.

5.6 CALCINING KILN – SO_2 BACT

5.6.1 BACKGROUND ON POLLUTANT FORMATION

SO_2 emissions are mostly attributed to the oxidation of the naturally occurring sulfur in the clay at high temperatures in the kiln. Minimal quantities of SO_2 also result from fuel combustion. Fuel based SO_2 emissions almost entirely depend upon the sulfur content of the fuel and are not dependent upon kiln properties. Since the fuel fired is natural gas (or propane as a backup), almost all of the sulfur released is in the form of SO_2 and resultant from the sulfur content of the clay materials processed. Based on a mass balance of material sulfur content, PyraMax calculated kiln uncontrolled SO_2 emissions.[39]

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[38] Uncontrolled NOx emissions based on an engineering estimate from similar kiln designs, with an applied safety factor. Although vendor documentation for the Catalytic Baghouse system has indicated the potential for up to a 95% removal of NOx emissions, no documentation was found regarding that control technology's implementation at a similar source to the PyraMax facility. Therefore, due to the uncertainty in the control technology effectiveness in such an application, a lower control efficiency of 80% has been selected for derivation of proposed emission limits. Documentation reviewed regarding the Carbo Ceramics, Inc. Toomsboro permit revealed a regimen of testing required (weekly/quarterly) for demonstration of compliance with facility NOx emission limits. At this time, it is unclear if such regimented testing would be required for PyraMax. PyraMax will work with EPD in establishment of a sufficient compliance demonstration schedule for demonstration of compliance with proposed emission limits.

[39] Based on email from SSOE Group to Alberici Group on May 31, 2011, based on mass balance of material sulfur content.

5.6.2 IDENTIFICATION OF POTENTIAL CONTROL TECHNIQUES (STEP 1)

Candidate control options identified from the RBLC search and the literature review include those classified as pollution reduction techniques.[40] SO_2 pollution reduction options include:

- ▲ Catalytic Baghouse System
- ▲ Wet Scrubber/Flue Gas Desulfurization (FGD)
- ▲ Dry FGD or Semi-Dry Scrubber
- ▲ Duct Sorbent Injection (DSI)

These control technologies are briefly discussed in the following sections.

5.6.2.1 CATALYTIC BAGHOUSE SYSTEM

The Catalytic Baghouse system utilizes a dry injection of sodium or calcium based sorbents such as sodium bicarbonate or trona for the control of acid gases in the flue gas stream (i.e. SO_2). Vendor documentation provided has estimated a control efficiency of 90-98 percent reduction of SO_2 emissions with use of the Catalytic Baghouse system.

5.6.2.2 WET SCRUBBER/FGD

In a FGD or wet scrubber system, a liquid alkaline sorbent is sprayed into the flue gas in a vessel to adsorb SO_2 from the flue gas. The SO_2 reacts with the alkaline liquid and is removed in solution as a liquid waste. Additional sorbent solution is added to the recirculating sorbent solution to compensate for the quantity that reacts with SO_2.[41] Typically, large quantities of liquid waste are disposed of by wastewater treatment holding ponds. Estimated control efficiencies range between 90 and 98 percent reduction.[42]

5.6.2.3 DRY FGD OR SEMI-DRY SCRUBBER

This system requires installation of a spray dryer and a baghouse. An alkaline slurry is injected by a spray dryer into the flue gas in the form of fine droplets under well controlled conditions such that the droplets will absorb SO_2 from the flue gas and then become dry particles because of the evaporation of water. The dry particles are captured by the baghouse downstream of the dryer. The

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[40] Sulfur content of clay materials can vary depending on the source of the material. Selection/research/acquisition of only low sulfur clay materials would potentially reduce the facility SO_2 emissions. However, selection of only low sulfur clay materials would limit selection of raw material resources for the facility, and limit operational flexibility of the source. Therefore, use of only low sulfur clay materials has not been considered in this assessment.

[41] U.S. EPA, CATC Fact Sheet for FGD, EPA-452/F-03-034. http://www.epa.gov/ttn/catc/dir1/ffdg.pdf

[42] Per U.S. EPA Clean Air Technology Center, Air Pollution Control Technology Fact Sheet for Wet FGD: http://www.epa.gov/ttn/catc/dir1/ffdg.pdf

captured particles are then removed from the system and disposed. The advantages of this system include a dry waste product and simpler process control.[43] Estimated control efficiencies range between 80 and 90 percent reduction.[44]

5.6.2.4 DUCT SORBENT INJECTION (DSI)

Sorbent injection systems are typically placed in between the air heater outlet and particulate control inlet, where the sorbent is injected into the flue gas either dry or damp. A humidifier can then be used to cool the flue gas through evaporation to approach the adiabatic saturation temperature of the flue gas. This creates an atmosphere that allows for this technology to be most effective. Additionally, a fabric filter is instrumental in achieving SO_2 removal due to the intimate contact between the flue gases and sorbent in the filter cake.[45] Estimated control efficiencies range between 50 and 60 percent reduction, but can be up to 90% depending on the efficiency of the system.[46] This system is effectively the same control system concept as used by the Catalytic Baghouse system.

5.6.3 ELIMINATION OF TECHNICALLY INFEASIBLE CONTROL OPTIONS (STEP 2)

After the identification of control options, the second step in the BACT assessment is to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that would prohibit the implementation of the control or if the highest control efficiency of the option would result in an emission level that is higher than any applicable regulatory limits. All previously identified control technologies are technically feasible.

5.6.4 RANK OF REMAINING CONTROL TECHNOLOGIES (STEP 3)

The third of the five steps in the top-down BACT assessment procedure is to rank technically feasible control technologies by control effectiveness. The remaining control technologies are presented in Table 5-3.

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[43] Kitto, J.B. *Air Pollution Control For Industrial Boiler Systems.* Barberton, OH: Babcock & Wilcox. November 1996. http://www.babcock.com/library/pdf/BR-1624.pdf

[44] Per U.S. EPA Clean Air Technology Center, Air Pollution Control Technology Fact Sheet for Dry FGD: http://www.epa.gov/ttn/catc/dir1/ffdg.pdf

[45] Ibid.

[46] Per U.S. EPA Clean Air Technology Center, Air Pollution Control Technology Fact Sheet for DSI: http://www.epa.gov/ttn/catc/dir1/ffdg.pdf

TABLE 5-3. REMAINING SO_2 CONTROL TECHNOLOGIES

Rank	Control Technology	Potential Control Efficiency (%)
1	Catalytic Baghouse System	90-98%
2	Wet Scrubber	90-98%
3	Dry or Semi-Dry Scrubber	80-90%
4	Sorbent Injection	50-60%

5.6.5 EVALUATION OF MOST STRINGENT CONTROLS (STEP 4)

The fourth of the five steps in the top-down BACT assessment procedure is to evaluate the most effective control and document the results.

The highest ranked control technology, the Catalytic Baghouse system, would be cost effective for control of SO_2 emissions for the PyraMax facility, with cost effectiveness values well below $10,000/ton. Also, the energy and environmental impacts associated with use of this control equipment would be minimal. Recent documentation submitted by the Carbo Ceramics, Inc. McIntyre facility indicated that the facility now recognized the use of a wet scrubber as BACT for control of SO_2 emissions, and that the control technology could be economically feasible if seeking use of higher sulfur clay materials.[47] However, use of a wet scrubber would produce an additional waste stream (wastewater) that would require treatment and disposal, significantly increasing costs.

Since the estimated removal efficiencies of both the Catalytic Baghouse system and wet scrubber are the same, use of the Catalytic Baghouse will promote removal of other pollutants (i.e. NO_X), and the Catalytic Baghouse system will produce a lesser environmental and potential economic impact than the wet scrubber system, use of the Catalytic Baghouse system is the selected BACT control technology for the proposed kiln offering the highest potential control efficiency in combination with the control of other pollutants. This technology represents a high SO_2 removal while remaining cost effective and minimizing environmental and energy impacts.

5.6.6 SELECTION OF BACT (STEP 5)

Based on the previous analyses, PyraMax has determined that the Catalytic Baghouse system is the selected BACT control technology for the proposed facility kilns for control of SO_2 emissions.

Based on a review of the RBLC entries, kilns that combust natural gas generally accept combustion of a low sulfur fuel as BACT. Entries for facility processes such as cement kilns were found with references of use of control technologies such as wet scrubbers.

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[47] Application documentation submitted May 2010 for the Carbo Ceramics, Inc. McIntyre facility. Documentation reviewed indicated the proposed wetter scrubber installation on one of the facility calciners (CLN2) “will provide the critical operational flexibility in order to utilize higher sulfur crudes, thus maximizing the ability to continue to manufacture a diverse range of products”. The estimated SO_2 control efficiency for the scrubber was indicated as 95%.

However, direct comparison of controls for such systems is difficult due to the differences in the facility processes between cement and ceramic proppant production. The most comparable sources to the PyraMax facility are the Carbo Ceramics, Inc. Toomsboro and McIntyre Georgia facilities. Both facilities, established as part of permitting action BACT emission limits of 34.25 lb/hr out of each kiln.[48]

Based on an uncontrolled emission rate estimate of 4.99 lb uncontrolled SO_2/ton processed, and a control efficiency of 90%, a BACT emission limit of 11.64 lb/hr SO_2 emissions is proposed, with compliance demonstrated through per periodic stack testing per EPA Method 6 or 6C, or other methodologies as may be approved by the Division.[49]
The selected BACT control technology is use of a Catalytic Baghouse system.

5.7 CALCINING KILN – CO BACT

5.7.1 BACKGROUND ON POLLUTANT FORMATION

CO from kilns are generated from two independent sources –by-product of incomplete combustion of the fuel, and incomplete combustion/oxidation of carbon in the clay. Conditions leading to incomplete combustion include the following: insufficient oxygen availability, poor fuel/air mixing, reduced combustion temperature, reduced combustion gas residence time, and load reduction. In addition, combustion modifications taken to reduce NO_X emissions may result in increased CO emissions.

5.7.2 IDENTIFICATION OF POTENTIAL CONTROL TECHNIQUES (STEP 1)

Candidate control options identified from the RBLC search and the literature review include those classified as pollution reduction techniques. CO reduction options include:

- Regenerative Thermal Oxidizer (RTO)
- Oxidation Catalyst
- Good combustion techniques

These control technologies are briefly discussed in the following sections.

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[48] Permit No. 3295-319-0029-V-02-1, 3295-319-0027-V-03-2

[49] Uncontrolled SO_2 emissions based on a mass balance of projected material sulfur content. Although vendor documentation for the Catalytic Baghouse system has indicated the potential for up to a 98% removal of SO_2 emissions, no documentation was found regarding that control technology's implementation at a similar source to the PyraMax facility. Therefore, due to the uncertainty in the control technology effectiveness in such an application, a lower control efficiency of 90% has been selected for derivation of proposed emission limits. Documentation reviewed regarding the Carbo Ceramics, Inc. McIntyre permit revealed that a control efficiency of 95% had been indicated for the scrubber for calciner CLN2. Permit 3295-319-0027-V-03-3 for the facility implemented permit conditions for determination of the actual removal efficiency of the facility scrubber. The SO_2 emission limits established by Permit No. 3295-319-0027-V-03-2 for the facility kilns was not changed (34.25 lb/hr). At this time, results of such site analyses for determination of scrubber removal efficiencies are unclear as documentation was not able to be located within Georgia EPD files. PyraMax will work with EPD in establishment of a sufficient compliance demonstration schedule and monitoring provisions for demonstration of compliance with proposed emission limits.

5.7.2.1 REGENERATIVE THERMAL OXIDIZER (RTO)

An RTO is typically used for volatile organic compound (VOC) control by oxidizing the VOC to CO_2. Similarly, an RTO can also be used to oxidize CO to CO_2 with a destruction efficiency of around 98%.[50] The RTO system uses a bed of ceramic material to absorb and retain heat from the combustion exhaust gas and uses this heat to preheat the incoming flue gas stream.

5.7.2.2 OXIDATION CATALYST

CO emissions resulting from natural gas combustion can be decreased via an oxidation catalyst control system. The oxidation is carried out by the following overall reaction:

$CO + \frac{1}{2}O_2 \rightarrow CO_2$

This reaction is promoted by several noble metal-enriched catalysts at high temperatures. Under optimum operating temperatures, this technology can generally achieve approximately 95% reduction efficiency for CO emissions.[51]

Oxidation efficiency also depends on exhaust flow rate and composition. Residence time required for oxidation to take place at the active sites of the catalyst may not be achieved if exhaust flow rates exceed design specifications. Also, sulfur and other compounds may foul the catalyst, leading to decreased efficiency.

Catalyst fouling occurs slowly under normal operating conditions and is accelerated by even moderate sulfur concentrations in the exhaust gas. The catalyst may be chemically washed to restore its effectiveness, but eventually irreversible degradation occurs. The catalyst replacement timeframe varies depending on type and operating conditions.

5.7.2.3 GOOD COMBUSTION TECHNIQUES

Ensuring that the temperature, oxygen availability and residence time are adequate for complete combustion minimizes CO formation. This technique includes continued operation of the kiln at the appropriate oxygen range and temperature. In addition, using raw materials containing relatively low carbon and hydrocarbons can reduce the amount of CO formed.

5.7.3 ELIMINATION OF TECHNICALLY INFEASIBLE CONTROL OPTIONS (STEP 2)

After the identification of control options, the second step in the BACT assessment is to eliminate technically infeasible options. A control option is eliminated from consideration

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[50] Based upon the OAQPS Manual, Section 3.2, Chapter 2, page 2-7.

[51] Based upon EPA's Air Pollution Control Technology Fact Sheet: http://www.epa.gov/ttn/catc/dir1/fcataly.pdf

if there are process-specific conditions that would prohibit the implementation of the control or if the highest control efficiency of the option would result in an emission level that is higher than any applicable regulatory limits. All previously identified control technologies are technically feasible. However, it should be noted that research of similar facilities could find no reference of add-on control technologies used for control of CO emissions, with the most common control technology listed as use of good combustion and good engineering practices.

5.7.4 RANK OF REMAINING CONTROL TECHNOLOGIES (STEP 3)

The third of the five steps in the top-down BACT assessment procedure is to rank technically feasible control technologies by control effectiveness. The remaining control technologies are presented in Table 5-4.

TABLE 5-4. REMAINING CO CONTROL TECHNOLOGIES

Rank	Control Technology	Potential Control Efficiency (%)
1	RTO	98%
2	Oxidation Catalyst - with reheat	95%
5	Good Combustion Practices	Base Case

5.7.5 EVALUATION OF MOST STRINGENT CONTROLS (STEP 4)

The fourth of the five steps in the top-down BACT assessment procedure is to evaluate the most effective control and document the results. This has been performed for the remaining control technologies on the basis of economic, energy, and environmental considerations, and is described below.

5.7.5.1 REGENERATIVE THERMAL OXIDIZER

The current cost of controlling CO with a RTO system is estimated at approximately $21,000 per ton of CO reduced. Energy impacts associated with use of this technology would include combustion of natural gas to reheat the flue gas, also leading to subsequent environmental impacts from use of natural gas leading to additional pollutant emissions such as NO_X emissions. Also, as mentioned above, there is no reported use of such technologies on similar sources such as the kilns to be installed at the PyraMax facility. Use of an RTO for control of CO emissions from such a source would be considered experimental. Therefore, the cost estimates provided would likely increase due to the potential for additional research and technology modifications for implementation of the technology on a source such as the kilns at the PyraMax facility.

PyraMax has determined that use of an RTO is not BACT based on the environmental, energy and economic analyses. Reference documentation regarding the cost analysis can be found in Appendix D.

5.7.5.2 OXIDATION CATALYST

PyraMax evaluated the environmental, energy, and economic impacts of the reheat required oxidation catalyst scenarios. The current cost of controlling CO with an oxidation catalyst system is estimated at approximately $14,000 per ton of CO reduced. Environmental impacts are greater for the reheat scenario as additional fuel must be combusted. This additional fuel combustion needed to raise the temperature of the flue gas to a range of 600-800 °F where optimal removal efficiencies occur would lead to additional facility emission sources of pollutants such as NO_X.[52] Energy impacts include combustion of additional natural gas to reheat the flue as well as additional fan capacity associated with pressure drop from the oxidation catalyst itself.

The oxidation catalyst must be installed downstream of the particulate control device to ensure that the catalyst is not chemically damaged. In the instance of the PyraMax facility, this would be downstream of the Catalytic Baghouse system. The Catalytic Baghouse system vendor documentation did not indicate that the system would be effective at control of CO emissions. Also, use of catalytic oxidation for control of CO emissions from such a source would be considered experimental, as research did not reveal any installation of such a control technology on similar sources. Therefore, cost estimates provided would likely increase due to the potential for additional research and technology modifications for implementation of the technology on a source such as the kilns at the PyraMax facility.

Hence, PyraMax has determined that an oxidation catalyst is not BACT based on the environmental, energy, and economic analyses. Reference documentation regarding the cost analysis can be found in Appendix D.

5.7.5.3 GOOD COMBUSTION TECHNIQUES

The only remaining technology is good design and operating practices, a logical option since a properly designed and operated burner design within the kiln can effectively minimize CO formation. This is done by good design of the kiln and effective operating engineering practices that promotes complete combustion. Good design and operating practices is considered BACT for CO for the proposed kiln.

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[52] Estimated average (600F - 800F) needed per EPA Spec Sheet http://www.epa.gov/ttn/catc/dir1/fcataly.pdf

5.7.6 SELECTION OF BACT (STEP 5)

Based on the previous analyses, PyraMax has determined that employing good combustion technique is the selected BACT control technology for the proposed kiln. There are no negative environmental and energy impacts associated with this option. In addition, the RBLC search proves that good combustion techniques are widely accepted as BACT for kilns.

The most comparable similar sources to the PyraMax facility are the Carbo Ceramics, Inc. Toomsboro and McIntyre facilities. These facilities have established BACT CO emission limits of 24.5 lb/hr CO emissions per kiln.[53]

Based on an emission rate estimate of 2.2 lb/ton material processed CO emissions, a BACT emission limit of 51.36 lb/hr CO emissions is proposed, with compliance demonstrated through per periodic stack testing per EPA Method 10, or other methodologies as may be approved by the Division.[54]. The selected BACT control technology is use of good combustion practices.

5.8 CALCINING KILN – PM/PM_{10}/$PM_{2.5}$ BACT

5.8.1 BACKGROUND ON POLLUTANT FORMATION

PM/PM_{10}/$PM_{2.5}$ emissions are generated from the calcining of the clay in the kiln as well as a minimal amount from the combustion of natural gas/propane. The kiln is a point source of particulate emissions.

5.8.2 IDENTIFICATION OF POTENTIAL CONTROL TECHNIQUES (STEP 1)

Candidate control options identified from the RBLC search and the literature review include those classified as pollution reduction techniques. Application of a control technology differs for point sources and fugitive sources. PM reduction options from point sources include:

- Baghouse
- Electrostatic Precipitator (ESP)
- Wet Scrubbing
- Venturi Scrubber

These control technologies are briefly discussed in the following sections.

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[53] Permit No. 3295-319-0029-V-02-1, 3295-319-0027-V-03-2

[54] Uncontrolled CO emissions based on emission factors for gas fired rotary kilns, AP-42, Section 11.17-6. The Carbo Ceramics, Inc. values were not selected as BACT due to the uncertainty in the ability to demonstrate compliance with those values based on historic site testing information (i.e. June 29, 2010 stack testing of Carbo Ceramics, Inc. Toomsboro facility).

5.8.2.1 BAGHOUSE

A baghouse consists of several fabric filters, typically configured in long, vertically suspended sock-like configurations. Dirty gas enters from one side, often from the outside of the bag, passing through the filter media and forming a particulate cake. The cake is removed by shaking or pulsing the fabric, which loosens the cake from the filter, allowing it to fall into a bin at the bottom of the baghouse. The air cleaning process stops once the pressure drop across the filter reaches an economically unacceptable level. Typically, the trade-off to frequent cleaning and maintaining lower pressure drops is the wear and tear on the bags produced in the cleaning process.[55] A baghouse can generally achieve approximately 99-99.9% reduction efficiency for PM emissions.[56]

5.8.2.2 ELECTROSTATIC PRECIPITATOR (ESP)

An ESP removes particles from an air stream by electrically charging the particles then passing them through a force field that causes them to migrate to an oppositely charged collector plate. After the particles are collected, the plates are knocked (“rapped”), and the accumulated particles fall into a collection hopper at the bottom of the ESP. The collection efficiency of an ESP depends on particle diameter, electrical field strength, gas flow rate, and plate dimensions. An ESP can be designed for either dry or wet applications.[57] An ESP can generally achieve approximately 99-99.9% reduction efficiency for PM emissions.[58]

5.8.2.3 WET SCRUBBING

Wet scrubbers remove PM by impacting the exhaust gas with the scrubbing solution. This technology generates wastewater and sludge disposal problems along with substantial energy requirements for pumping water and exhausting the cooled air stream out the stack. The control efficiency offered by wet scrubbing is not as high as the baghouse or ESP. A wet scrubber can generally achieve approximately 80-99% reduction efficiency for PM emissions.[59]

5.8.2.4 VENTURI SCRUBBER

Venturi scrubbers intercept dust particles using droplets of liquid (usually water). The larger, particle-enclosing water droplets are separated from the

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[55] Ibid.

[56] Based on EPA's Air Pollution Control Technology Fact Sheet: http://www.epa.gov/ttn/catc/dir1/ff-pulse.pdf

[57] Kitto, J.B. *Air Pollution Control for Industrial Boiler Systems.* Barberton, OH: Babcock & Wilcox. November 1996. http://www.babcock.com/library/pdf/BR-1624.pdf

[58] Based on EPA's Air Pollution Control Technology Fact Sheet: http://www.epa.gov/ttn/catc/dir1/fdespwpi.pdf

[59] Based on EPA's Air Pollution Control Technology Fact Sheet: http://www.epa.gov/ttn/catc/dir1/fmechcal.pdf

remaining droplets by gravity. The solid particulates are then separated from the water. The waste water must be properly treated. A Venturi Scrubber generally achieves less than 90% reduction efficiency for PM emissions.[60]

5.8.3 ELIMINATION OF TECHNICALLY INFEASIBLE CONTROL OPTIONS (STEP 2)

After the identification of control options, the second step in the BACT assessment is to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that would prohibit the implementation of the control or if the highest control efficiency of the option would result in an emission level that is higher than any applicable regulatory limits. All of the above mentioned options are technically feasible for control of PM from the kilns.

5.8.4 RANK OF REMAINING CONTROL TECHNOLOGIES (STEP 3)

The third of the five steps in the top-down BACT assessment procedure is to rank technically feasible control technologies by control effectiveness. The remaining control technologies are presented in Table 5-5.

TABLE 5-5. REMAINING PM/PM$_{10}$/PM$_{2.5}$ CONTROL TECHNOLOGIES

Rank	Control Technology	Potential Control Efficiency (%)
1	Baghouse and ESP	> 99%
2	Wet Scrubbing	< 99%
5	Venturi Scrubber	< 90%

5.8.5 EVALUATION OF MOST STRINGENT CONTROLS (STEP 4)

PyraMax has determined that using the top control technology of a baghouse control system for the kiln is BACT. A baghouse will be installed at the exhaust stream of the kiln to control PM emissions. The facility Catalytic Baghouse system selected for control of other pollutants would have the same expected performance for PM removal, if not better, than a standard baghouse system. Use of a baghouse system offers co-benefit for removal of other pollutants (i.e. acid gases) than an ESP system as it provides for additional reaction sites as unspent sorbent collects on the filter bags of the baghouse system.

5.8.6 SELECTION OF BACT (STEP 5)

A review of RBLC entries demonstrates that baghouses are widely accepted as BACT for control of PM emissions from kilns. In addition, since baghouses offer the highest control of PM emissions, PyraMax has determined that a baghouse is the appropriate BACT control technology for the proposed kiln.

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[60] Based on EPA’s Air Pollution Control Technology Fact Sheet http://www.epa.gov/ttn/catc/dir1/fventuri.pdf

The most comparable similar sources to the PyraMax facility are the Carbo Ceramics, Inc. Toomsboro and McIntyre facilities. Emission limits for PM for these facilities has been established as 0.010 gr/dscf.[61] These limits were established with demonstrate of compliance per EPA Method 5, or Method 201 or 201A in conjunction with Method 202 if necessary. Therefore, these emission limits are perceived to be indicative of filterable emissions only, and not inclusive of potential emissions.

The filterable PM/PM_{10} BACT emission limit proposed for the PyraMax facility kilns is proposed as 0.01 gr/dscf. The proposed filterable $PM_{2.5}$ emission limit is proposed as 0.006 gr/dscf. A small amount of condensable PM/PM_{10}/$PM_{2.5}$ was estimated from the facility kilns, resultant from emissions of small amounts of organic condensables and acid gases from the facility kilns.[62] This small amount of condensable emissions will be effectively controlled through control of acid gases, VOCs, etc. The total proposed PM/PM_{10} limit is proposed as 8.53 lb/hr, and the total proposed $PM_{2.5}$ limit is 6.98 lb/hr (both including condensables). Compliance will be demonstrated through period stack testing per EPA Method 201/201A and Method 202.

5.9 CALCINING KILN - VOC BACT

5.9.1 BACKGROUND ON POLLUTANT FORMATION

VOC from the kiln is generated as a result of natural gas/propane combustion. Carbon in the fuel that is not oxidized completely results in VOC formation.

5.9.2 IDENTIFICATION OF POTENTIAL CONTROL TECHNIQUES (STEP 1)

Candidate control options identified from the RBLC search and the literature review include those classified as pollution reduction techniques. VOC reduction options include:

- Regenerative Thermal Oxidizer (RTO)
- Oxidation Catalyst
- Good combustion techniques

These control technologies are briefly discussed in the following sections.

5.9.2.1 REGENERATIVE THERMAL OXIDIZER (RTO)

As described in Section 6.7.2.1, an RTO is used for VOC control by oxidizing the VOC to CO_2.

5.9.2.2 OXIDATION CATALYST

As described in Section 6.7.2.2, an oxidation catalyst can also be used to oxidize VOC to form CO_2.

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[61] Permit No. 3295-319-0029-V-02-1, 3295-319-0027-V-03-2

[62] Filterable $PM_{2.5}$ limit based on AP-42, Table 11.25-4 for flash calciner controlled by fabric filter. Condensable PM emission estimate based on AP-42, Section 11.6, Table 11-6-2 for Portland cement. Please see Appendix C for further documentation.

5.9.2.3 GOOD COMBUSTION TECHNIQUES

Ensuring that the temperature, oxygen availability and residence time are adequate for complete combustion minimizes VOC formation. This technique includes continued operation of the kiln at the appropriate oxygen range and temperature.

5.9.3 ELIMINATION OF TECHNICALLY INFEASIBLE CONTROL OPTIONS (STEP 2)

After the identification of control options, the second step in the BACT assessment is to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that would prohibit the implementation of the control or if the highest control efficiency of the option would result in an emission level that is higher than any applicable regulatory limits. All previously identified control technologies are feasible.

5.9.4 RANK OF REMAINING CONTROL TECHNOLOGIES (STEP 3)

The third of the five steps in the top-down BACT assessment procedure is to rank technically feasible control technologies by control effectiveness. The remaining control technologies are presented in Table 5-6.

TABLE 5-6. REMAINING VOC CONTROL TECHNOLOGIES

Rank	Control Technology	Potential Control Efficiency (%)
1	RTO	98%
2	Oxidation Catalyst - with reheat	95%
5	Good Combustion Practices	Base Case

5.9.5 EVALUATION OF MOST STRINGENT CONTROLS (STEP 4)

The fourth of the five steps in the top-down BACT assessment procedure is to evaluate the most effective control and document the results. This has been performed for the remaining control technologies on the basis of economic, energy, and environmental considerations, and is described below.

5.9.5.1 REGENERATIVE THERMAL OXIDIZER

The cost of using an RTO on the kiln exceeds the benefit of the VOC reduction it offers. The current cost of controlling VOC with a RTO system is estimated at more than $2,200,000 per ton of VOC reduced. This control technology is not cost effective, due primarily to the small amount of actual VOC emissions (approximately two tons per year) estimated to be emitted from the emission unit. Also, use of an RTO system would increase use of natural gas, leading to increased energy and environmental impacts due to increased emissions of pollutants such as NO_X due to the additional combustion of natural gas.

PyraMax has determined that an RTO is not BACT based on the environmental, energy and economic analyses. Control cost documentation can be found in Appendix D.

5.9.5.2 OXIDATION CATALYST

The cost of using an oxidation catalyst on the kiln exceeds the benefit of the VOC reduction it offers. The current cost of controlling VOC with a RTO system is estimated at more than $1,400,000 per ton of VOC reduced. This control technology is not cost effective, due primarily to the small amount of actual VOC emissions (approximately two tons per year) estimated to be emitted from the emission unit. Also, use of an oxidation catalyst system would increase use of natural gas, leading to increased energy and environmental impacts due to increased emissions of pollutants such as NO_X due to the additional combustion of natural gas.

Hence, PyraMax has determined that an oxidation catalyst is not BACT based on the environmental, energy, and economic analyses. Control cost documentation can be found in Appendix D.

5.9.5.3 GOOD COMBUSTION TECHNIQUES

The only remaining technology is good design and operating practices, a logical option since a properly designed and operated calcining kiln can effectively minimize VOC formation. This is done by ensuring good design of the kiln that promotes complete combustion. Good design and operating practices is considered BACT for VOC for the proposed kiln.

5.9.6 SELECTION OF BACT (STEP 5)

Based on the previous analyses, PyraMax has determined that employing good combustion technique is BACT for the proposed kiln. There are no negative environmental and energy impacts associated with this option. In addition, the RBLC search proves that good combustion techniques are widely accepted as BACT control technology for VOC emissions for kilns.

The most comparable similar sources to the PyraMax facility are the Carbo Ceramics, Inc. Toomsboro and McIntyre facilities. These facilities did not undergo BACT for VOC emissions as part of permitting actions undertaken in 2009.[63] The BACT emission limit for VOC emissions proposed for the facility kilns is 0.54 lb/hr per kiln, with compliance demonstrated per EPA Method 25A per periodic stack testing.[64]

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[63] Permit No. 3295-319-0029-V-02-1, 3295-319-0027-V-03-2

[64] Emission limit proposed based on VOC emission estimate from AP-42, Section 1.5 for propane (1 lb/1,000 gallons).

5.10 PELLETIZER - NO_X BACT

5.10.1 BACKGROUND ON POLLUTANT FORMATION

The pelletizers combust natural gas with propane as a backup. NO_X from pelletizers are primarily due to natural gas combustion. Thermal NO_X generation would be expected to be minimal since the temperature at which the pelletizers operate are significantly lower than the ceramic kilns. Literature review could find no mention of control technologies being employed for control of NO_X emissions from similar sources.

5.10.2 IDENTIFICATION OF POTENTIAL CONTROL TECHNIQUES (STEP 1)

Candidate control options identified from the RBLC search and the literature review include those classified as pollution reduction techniques. NO_X reduction options include:[65]

- ▲ Selective Non-Catalytic Reduction (SNCR)
- ▲ Selective Catalytic Reduction (SCR)
- ▲ Good Design and Operating Practices such as low NO_X burners/combustion control

These control technologies were briefly discussed in Sections 6.5.2.2 through 6.5.2.3.

5.10.3 ELIMINATION OF TECHNICALLY INFEASIBLE CONTROL OPTIONS (STEP 2)

After the identification of control options, the second step in the BACT assessment is to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that would prohibit the implementation of the control or if the highest control efficiency of the option would result in an emission level that is higher than any applicable regulatory limits. All previously identified control technologies are technically feasible.

5.10.4 RANK OF REMAINING CONTROL TECHNOLOGIES (STEP 3)

The third of the five steps in the top-down BACT assessment procedure is to rank technically feasible control technologies by control effectiveness. The remaining control technologies are presented in Table 5-7.

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[65] The catalytic baghouse system determined for use for the facility kilns for multi-pollutant control was not evaluated for emission units outside of the kilns. The system would not be cost effective for control of pollutants such as NOx, SO_2, etc. from other facility sources due to the low level of anticipated emissions of those pollutants from those sources.

TABLE 5-7. REMAINING NO_X CONTROL TECHNOLOGIES

Rank	Control Technology	Potential Control Efficiency (%)
1	SCR	70-90%
2	SNCR	65-75%
3	Good Combustion Practices	Base Case

5.10.5 EVALUATION OF MOST STRINGENT CONTROLS (STEP 4)

The fourth of the five steps in the top-down BACT assessment procedure is to evaluate the most effective control and document the results. This has been performed for the remaining control technologies on the basis of economic, energy, and environmental considerations, and is described below.

5.10.5.1 SELECTIVE CATALYTIC REDUCTION (SCR)

A tail end SCR works by reheating the flue gas to the necessary temperatures for the ammonia and NO_X to react to form nitrogen and water. Tail end SCR control technology has been demonstrated for various industries. The efficiency of this system on boilers has successfully been determined at up to 90% NO_X.

PyraMax evaluated the environmental, energy, and economic impacts of using a tail end SCR. Energy and environmental impacts associated with use of an SCR system would involve use of ammonia (leading to increased toxic emissions), as well as additional energy impacts needed for possible gas stream heating and pressure drop considerations. Total NO_X emissions from the facility pelletizers are estimated at less than 10 ton/yr. The estimated cost effectiveness for such a control technology for the pelletizers would be greater than $20,000 per ton. Refer to detailed calculations included in Appendix D for more information regarding the economic analysis.

PyraMax has determined that an SCR system is not BACT based on the environmental, energy, and economic analyses.

5.10.5.2 SNCR

SNCR has not been utilized on any pelletizers according to RBLC entries. SNCR systems are generally thought to have a NO_X reduction efficiency of 65 to 75%.

PyraMax evaluated the environmental, energy, and economic impacts of using a SNCR. The estimated cost effectiveness of an SNCR system would be greater than $20,000 per ton. This system would not be considered cost effective. Refer to detailed calculations included in Appendix D for more information regarding the economic analysis. Additional energy and environmental impacts with use of this system would be expected with increased ammonia emissions, and equipment needed for the ammonia injection systems.

PyraMax has determined that a SNCR is not BACT based on the environmental, energy, and economic analysis.

5.10.5.3 GOOD DESIGN AND OPERATING PRACTICES

Since good design and operation is not an exhaust stream control technique, no adverse environmental, energy or economic impacts are associated with this technique. Hence, PyraMax has determined that good design, operating practices, and combustion controls is BACT for the pelletizers. The facility pelletizers will utilize Low NO_X burners to minimize combustion related NO_X emissions.

5.10.6 SELECTION OF BACT (STEP 5)

Based on the previous analyses, PyraMax has determined that good design and operating practice is BACT for the proposed pelletizer, with use of low NO_X burners as the selected control technology for control of NO_X emissions.

The most comparable similar source identified is the pelletizer units at the Carbo Ceramics, Inc. Toomsboro facility. That facility has established emission limits for each spray dryer of 8.3 lbs/hr of NO_X emissions.[66] The proposed emission limit for the PyraMax facility emission units is 2.25 lb/hr, with compliance demonstrated per period stack testing with EPA Method 7 or 7E.[67]

5.11 PELLETIZER – SO_2 BACT

5.11.1 BACKGROUND ON POLLUTANT FORMATION

SO_2 emissions result from the oxidation of sulfur in the fuel during the combustion process and by oxidation of the naturally occurring sulfur in the clay in the pelletizers, which from the pelletizers is presumed to be minimal. Fuel based SO_2 emissions almost entirely depend upon the sulfur content of the fuel and are not dependent upon pelletizer properties. Since the fuel fired is natural gas, almost all of the sulfur released is in the form of SO_2. Literature review could find no mention of control technologies being employed for control of SO_2 emissions from similar sources.

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[66] Permit No. 3295-319-0029-V-02-1

[67] Emission limit for pelletizers proposed based on vendor guarantee information for low NOx burner systems for the pelletizer of 0.03 lb/MMBtu.

5.11.2 IDENTIFICATION OF POTENTIAL CONTROL TECHNIQUES (STEP 1)

Candidate control options identified from the RBLC search and the literature review include those classified as pollution reduction techniques. SO_2 reduction options include:

- Wet Scrubber
- Dry or Semi-Dry Scrubber
- Sorbent Injection

These control technologies are briefly discussed in the following sections.

5.11.2.1 WET SCRUBBER

As described in Section 6.6.2.2, a wet scrubber system uses a liquid alkaline sorbent spray to adsorb SO_2 from the flue gas.

5.11.2.2 DRY OR SEMI-DRY SCRUBBER

As described in Section 6.6.2.3, this system requires installation of a spray dryer and a baghouse.

5.11.2.3 SORBENT INJECTION

As described in Section 6.6.2.4, sorbent injection systems involve injecting a sorbent into the flue gas either dry or damp. A fabric filter is then used to remove the SO_2 in the filter cake.

5.11.3 ELIMINATION OF TECHNICALLY INFEASIBLE CONTROL OPTIONS (STEP 2)

After the identification of control options, the second step in the BACT assessment is to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that would prohibit the implementation of the control or if the highest control efficiency of the option would result in an emission level that is higher than any applicable regulatory limits. All previously identified control technologies are technically feasible.

5.11.4 RANK OF REMAINING CONTROL TECHNOLOGIES (STEP 3)

The third of the five steps in the top-down BACT assessment procedure is to rank technically feasible control technologies by control effectiveness. The remaining control technologies are presented in Table 5-8.

TABLE 5-8. REMAINING SO_2 CONTROL TECHNOLOGIES

Rank	Control Technology	Potential Control Efficiency (%)
1	Wet Scrubber	90-98%
2	Dry or Semi-Dry Scrubber	80-90%
3	Sorbent Injection	50-60%

5.11.5 EVALUATION OF MOST STRINGENT CONTROLS (STEP 4)

The fourth of the five steps in the top-down BACT assessment procedure is to evaluate the most effective control and document the results. This has been performed for the remaining control technologies on the basis of economic, energy, and environmental considerations, and is described below.

5.11.5.1 SORBENT INJECTION

As described earlier, the sorbent injection system uses dry calcium or sodium-based sorbent in conjunction with a baghouse.

Uncontrolled emissions of SO_2 emissions from the pelletizers are resultant from combustion of natural gas/propane, and are estimated at approximately 0.2 tpy. Assuming complete removal of SO_2 emissions, the annualized control cost for sorbent injection would only need to be $2,000 to exceed a cost effectiveness of $10,000 per ton. As the annualized operating costs associated with such a unit would likely exceed such a figure by $2,000 alone, sorbent injection would not be considered economically feasible for control of SO_2 emissions due to the very small amount of SO_2 emissions estimated from the facility pelletizers. There would also be associated energy impacts related to operation of the sorbent injection equipment, and environmental impacts related to the disposal of any additional spent sorbent collected in the system baghouse.

Based on the environmental, energy, and economic analyses, PyraMax has determined that sorbent injection is not BACT for the proposed pelletizers due to the minimal amount of SO_2 generated as part of the process.

5.11.5.2 WET SCRUBBER

As discussed earlier, wet scrubber systems are anticipated to reduce SO_2 outlet emissions from the proposed pelletizers by 90%. The capital and overall costs of a wet scrubber on a pelletizer are expected to be quite high relative to other sulfur control options.

Uncontrolled emissions of SO_2 emissions from the pelletizers are resultant from combustion of natural gas/propane, and are estimated at approximately

0.2 tpy. As with the sorbent injection system, assuming complete removal of SO_2 emissions, the annualized control cost for a wet scrubber would only need to be $2,000 to exceed a cost effectiveness of $10,000 per ton. As the annualized operating costs associated with such a unit would likely exceed such a figure by $2,000 alone, use of a wet scrubber would not be considered economically feasible for control of SO_2 emissions due to the very small amount of SO_2 emissions estimated from the facility pelletizers. There would also be associated energy impacts related to operation of the scrubber systems (pump equipment), and environmental impacts related to the disposal and treatment of any associated wastewater generated by the wet scrubber system.

Based on the environmental, energy, and economic analyses, PyraMax determined that a wet scrubber is not BACT for reducing SO_2 emissions from the proposed pelletizers.

5.11.5.3 DRY OR SEMI-DRY SCRUBBER

A spray dryer using alkaline slurry in combination with a baghouse is expected to achieve a control of 80% for the proposed pelletizers.

As with the sorbent injection system, assuming complete removal of SO_2 emissions, the annualized control cost for a dry scrubber system would only need to be $2,000 to exceed a cost effectiveness of $10,000 per ton. There would also be associated energy impacts related to operation of the dry scrubber systems (fan equipment), and environmental impacts related to the disposal of any additional sorbent materials collected by the system.

Based on the environmental, energy, and economic analyses, PyraMax has determined a dry scrubber system is not BACT for the proposed pelletizers due to the minimal amount of SO_2 generated as part of the process.

5.11.6 SELECTION OF BACT (STEP 5)

Based on the previous analyses, PyraMax has determined that BACT for the proposed pelletizers for SO_2 emissions is use of natural gas/propane to minimize combustion related SO_2 emissions. The proposed compliance demonstration is maintenance of facility records regarding the type and amount of fuel combusted in the pelletizers.

5.12 PELLETIZER – CO BACT

5.12.1 BACKGROUND ON POLLUTANT FORMATION

CO from the pelletizers are almost entirely from the incomplete combustion of carbon in the fuel. Conditions leading to incomplete combustion include the following: insufficient oxygen availability, poor fuel/air mixing, reduced combustion temperature, reduced combustion gas residence time, and load reduction. In addition, combustion modifications taken to reduce NO_X emissions may result in increased CO emissions. Literature review could find no mention of control technologies being employed for control of CO emissions from similar sources.

5.12.2 IDENTIFICATION OF POTENTIAL CONTROL TECHNIQUES (STEP 1)

Candidate control options identified from the RBLC search and the literature review include those classified as pollution reduction techniques. CO reduction options include:

- ▲ Regenerative Thermal Oxidizer (RTO)
- ▲ Oxidation Catalyst
- ▲ Good combustion techniques

Each of these control technologies were discussed in Sections 6.7.2.1 through 6.7.2.2.

5.12.3 ELIMINATION OF TECHNICALLY INFEASIBLE CONTROL OPTIONS (STEP 2)

After the identification of control options, the second step in the BACT assessment is to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that would prohibit the implementation of the control or if the highest control efficiency of the option would result in an emission level that is higher than any applicable regulatory limits. All previously identified control technologies are technically feasible.

5.12.4 RANK OF REMAINING CONTROL TECHNOLOGIES (STEP 3)

The third of the five steps in the top-down BACT assessment procedure is to rank technically feasible control technologies by control effectiveness. The remaining control technologies are presented in Table 5-9.

TABLE 5-9. REMAINING CO CONTROL TECHNOLOGIES

Rank	Control Technology	Potential Control Efficiency (%)
1	RTO	98%
2	Oxidation Catalyst - with reheat	95%
5	Good Combustion Practices	Base Case

5.12.5 EVALUATION OF MOST STRINGENT CONTROLS (STEP 4)

The fourth of the five steps in the top-down BACT assessment procedure is to evaluate the most effective control and document the results. This has been performed for the remaining control technologies on the basis of economic, energy, and environmental considerations.

5.12.5.1 REGENERATIVE THERMAL OXIDIZER

The cost of using an RTO on the pelletizers exceeds the benefit of the CO reduction it offers. The current cost of controlling CO with a RTO system is estimated at approximately $200,000 per ton of CO reduced. Energy and environmental related impacts would involve the increased use of natural gas, leading to emissions of additional pollutants such as NO_X.

PyraMax has determined that an RTO is not BACT for the pelletizers based on the environmental, energy and economic analyses. Detailed cost calculations can be found in Appendix D.

5.12.5.2 OXIDATION CATALYST

The oxidation catalyst must be installed downstream of the particulate control device to ensure that the catalyst is not chemically damaged. However, significant auxiliary fuel input will be required to raise the temperature of the flue gas.

The cost of using an oxidation catalyst on the pelletizers exceeds the benefit of the CO reduction it offers. The current cost of controlling CO with an oxidation catalyst system is estimated at approximately $145,000 per ton of CO reduced. Energy related impacts would involve the potential energy requirements to raise the exhaust gas stream temperature to a sufficient level to promote effective CO reduction.

PyraMax has determined that an oxidation catalyst system is not BACT for the pelletizers based on the environmental, energy and economic analyses. Detailed cost calculations can be found in Appendix D.

5.12.5.3 GOOD COMBUSTION TECHNIQUES

The only remaining technology is good design and operating practices, a logical option since a properly designed and operated pelletizer can effectively minimize CO formation. This is done by ensuring a good design of the pelletizer that promotes complete combustion. Good design and operating practices (good combustion controls) is considered BACT for CO for the proposed pelletizers.

5.12.6 SELECTION OF BACT (STEP 5)

Based on the previous analyses, PyraMax has determined that employing good combustion technique and use of good combustion controls is BACT for CO for the proposed pelletizers. There are no negative environmental and energy impacts associated with this option. In addition, the RBLC search proves that good combustion techniques are widely accepted as BACT for combustion units for CO emissions.

The most comparable similar source identified is the spray dryer units at the Carbo Ceramics, Inc. Toomsboro facility. That facility has established emission limits for each spray dryer of 16.6 lbs/hr of CO emissions.[68] The proposed emission limit for the PyraMax facility emission units is 13.73 lb/hr, with compliance demonstrated per period stack testing with EPA Method 10.

5.13 PELLETIZER – PM/PM$_{10}$/PM$_{2.5}$ BACT

5.13.1 BACKGROUND ON POLLUTANT FORMATION

PM/PM$_{10}$/PM$_{2.5}$ emissions from the pelletizer are generated from entrainment of raw material in the exhaust stream as well as a minimal amount from the combustion of natural gas. The pelletizers are point sources of particulate emissions.

5.13.2 IDENTIFICATION OF POTENTIAL CONTROL TECHNIQUES (STEP 1)

Candidate control options identified from the RBLC search and the literature review include those classified as pollution reduction techniques. Application of a control technology differs for point sources and fugitive sources. PM reduction options from point sources include:

- Baghouse
- Electrostatic Precipitator (ESP)
- Wet Scrubbing
- Venturi Scrubber

These control technologies are briefly discussed in Sections 6.8.2.1 through 6.8.2.4.

5.13.3 ELIMINATION OF TECHNICALLY INFEASIBLE CONTROL OPTIONS (STEP 2)

After the identification of control options, the second step in the BACT assessment is to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that would prohibit the implementation of the control or if the highest control efficiency of the option would result in an emission level that is higher than any applicable regulatory limits. All of the above mentioned options are technically feasible for control of PM from the pelletizers.

5.13.4 RANK OF REMAINING CONTROL TECHNOLOGIES (STEP 3)

The third of the five steps in the top-down BACT assessment procedure is to rank technically feasible control technologies by control effectiveness. The remaining control technologies are presented in Table 5-10.

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[68] Permit No. 3295-319-0029-V-02-1

TABLE 5-10. REMAINING PM/PM_{10}/$PM_{2.5}$ CONTROL TECHNOLOGIES

Rank	Control Technology	Potential Control Efficiency (%)
1	Baghouse and ESP	> 99%
2	Wet Scrubbing	< 99%
5	Venturi Scrubber	< 90%

5.13.5 EVALUATION OF MOST STRINGENT CONTROLS (STEP 4)

PyraMax has determined that using the top control technology of a fabric filter baghouse for the pelletizer is BACT. It is not anticipated that an ESP system would have improved PM control efficiency over that of a baghouse. Also, use of a fabric filter baghouse system can have co-benefit when considering control of other pollutants (i.e. condensable emissions). Therefore, a baghouse system will be installed at the exhaust stream of the pelletizer to control PM emissions.

5.13.6 SELECTION OF BACT (STEP 5)

Since baghouses offer the highest control of PM emissions and are widely accepted as BACT for control of PM emissions from point sources, PyraMax has determined that a baghouse is the appropriate BACT control technology for the proposed pelletizers.

The most comparable similar source identified is the spray dryer units at the Carbo Ceramics, Inc. Toomsboro facility. That facility has established emission limits for each spray dryer for PM/PM_{10} of 0.020 gr/dscf, not to exceed 4.54 lbs/hr, with compliance demonstrated per EPA Method 5 or Method 201 or 201A in conjunction with Method 202 if necessary.[69] Therefore, this limit is considered to represent only filterable PM only (not condensables). The proposed Total/Filterable PM/PM_{10} emission limit for the PyraMax facility emission units is 0.01 gr/dscf, with compliance demonstrated per period stack testing with EPA Method 201/201A, and 202 if deemed necessary. The proposed Total/Filterable $PM_{2.5}$ emission limit for the PyraMax facility emission units is 0.006 gr/dscf, with compliance demonstrated per period stack testing with EPA Method 201/201A, and 202 if deemed necessary.[70]

5.14 PELLETIZER - VOC BACT

5.14.1 BACKGROUND ON POLLUTANT FORMATION

VOC from the pelletizer is generated as a result of natural gas combustion. Carbon in the fuel that is not oxidized completely results in VOC formation. The process also involves

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[69] Permit No. 3295-319-0029-V-02-1

[70] Condensable PM emissions from the facility spray pelletizers is estimated to be negligible.

the addition of a material to the clay mixture process which contains a small amount of methanol and methyl acetate that is estimated to be emitted from the pelletizer process.[71]

5.14.2 IDENTIFICATION OF POTENTIAL CONTROL TECHNIQUES (STEP 1)

Candidate control options identified from the RBLC search and the literature review include those classified as pollution reduction techniques. VOC reduction options include:

- ▲ Regenerative Thermal Oxidizer (RTO)
- ▲ Oxidation Catalyst
- ▲ Good combustion techniques

These control technologies were briefly discussed in the Sections 6.7.2.1 through 6.7.2.2.

5.14.3 ELIMINATION OF TECHNICALLY INFEASIBLE CONTROL OPTIONS (STEP 2)

After the identification of control options, the second step in the BACT assessment is to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that would prohibit the implementation of the control or if the highest control efficiency of the option would result in an emission level that is higher than any applicable regulatory limits. All previously identified control technologies are technically feasible.

5.14.4 RANK OF REMAINING CONTROL TECHNOLOGIES (STEP 3)

The third of the five steps in the top-down BACT assessment procedure is to rank technically feasible control technologies by control effectiveness. The remaining control technologies are presented in Table 5-11.

TABLE 5-11. REMAINING VOC CONTROL TECHNOLOGIES

Rank	Control Technology	Potential Control Efficiency (%)
1	RTO	98%
2	Oxidation Catalyst - with reheat	95%
5	Good Combustion Practices	Base Case

5.14.5 EVALUATION OF MOST STRINGENT CONTROLS (STEP 4)

The fourth of the five steps in the top-down BACT assessment procedure is to evaluate the most effective control and document the results. This has been performed for the remaining control technologies on the basis of economic, energy, and environmental considerations, and is described below.

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[71] See the calculations in Appendix C for further emission estimation of these VOC compounds.

5.14.5.1 REGENERATIVE THERMAL OXIDIZER

The cost of using an RTO on the pelletizer exceeds the benefit of the VOC reduction it offers. The current cost of controlling VOC with an RTO system is estimated at approximately $60,000 per ton of VOC reduced. Energy and environmental impacts involving increased use of natural gas and emissions from use of that natural gas (i.e. NO_X emissions) would result.

PyraMax has determined that use of an RTO system is not BACT for control of VOC emissions based on the environmental, energy and economic analyses. Detailed cost calculations can be found in Appendix D.

5.14.5.2 OXIDATION CATALYST

The oxidation catalyst must be installed downstream of the particulate control device to ensure that the catalyst is not chemically damaged. However, significant auxiliary fuel input will be required to raise the temperature of the flue gas.

The cost of using an oxidation catalyst on the pelletizer exceeds the benefit of the VOC reduction it offers. The current cost of controlling VOC with an oxidation catalyst system is estimated at approximately $60,000 per ton of VOC reduced. Energy related impacts would involve the potential energy requirements to raise the exhaust gas stream temperature to a sufficient level to promote effective VOC reduction.

Hence, PyraMax has determined that an oxidation catalyst is not BACT based on the environmental, energy, and economic analyses. Detailed cost calculations can be found in Appendix D.

5.14.5.3 GOOD COMBUSTION TECHNIQUES

The only remaining technology is good design and operating practices (good combustion controls), a logical option since a properly designed and operated kiln combustion system can effectively minimize VOC formation. This is done by ensuring good design of the kiln that promotes complete combustion. Good design and operating practices is considered BACT for VOC for the proposed kiln. VOC emissions resultant from use of the additive materials are due to an impurity present within the material that is common to the raw material itself, and cannot be inherently avoided.

5.14.6 SELECTION OF BACT (STEP 5)

Based on the previous analyses, PyraMax has determined that employing good combustion technique (good combustion controls) is BACT for the proposed pelletizers. There are no negative environmental and energy impacts associated with this option. In addition, the RBLC search proves that good combustion techniques are widely accepted as BACT for similar equipment.

BACT is proposed as use of good combustion controls. An emission limit for the PyraMax facility emission units is proposed as 11.78 lb/hr, with compliance demonstrated per a mass balance based on kiln feed and VOC containing additive input records and MSDS information.

5.15 BOILER - NO_X BACT

5.15.1 BACKGROUND ON POLLUTANT FORMATION

The boilers combust natural gas with propane used as a backup. NO_X from the boilers are primarily due to thermal NO_X generation. NO_X formed in the high-temperature, post-flame region of the combustion equipment is "thermal NO_X." NO_X can also be formed as a result of fuel NO_X. "Fuel NO_X" forms when fuels containing nitrogen are burned. When these fuels are burned, the nitrogen bonds break and some of the resulting free nitrogen oxidizes to form NO_X. With excess air, the degree of fuel NO_X formation is primarily a function of the nitrogen content of the fuel. Therefore, since natural gas contains little or no fuel bound nitrogen, fuel NO_X is not a major contributor to NO_X emissions from natural gas-fired boilers.

5.15.2 IDENTIFICATION OF POTENTIAL CONTROL TECHNIQUES (STEP 1)

Candidate control options identified from the RBLC search and the literature review include those classified as pollution reduction techniques. NO_X reduction options include:

- ▲ Selective Non-Catalytic Reduction (SNCR)
- ▲ Selective Catalytic Reduction (SCR)
- ▲ Regenerative Selective Catalytic Reduction (RSCR)
- ▲ Good Design and Operating Practices such as low NO_X burners/combustion control

These control technologies were briefly discussed in Sections 6.5.2.2, 6.5.2.3, and 6.5.2.4.

5.15.3 ELIMINATION OF TECHNICALLY INFEASIBLE CONTROL OPTIONS (STEP 2)

After the identification of control options, the second step in the BACT assessment is to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that would prohibit the implementation of the control or if the highest control efficiency of the option would result in an emission level that is higher than any applicable regulatory limits. All previously identified control technologies are technically feasible for control of NO_X emissions from the facility natural gas boiler.

5.15.4 RANK OF REMAINING CONTROL TECHNOLOGIES (STEP 3)

The third of the five steps in the top-down BACT assessment procedure is to rank technically feasible control technologies by control effectiveness. The remaining control technologies are presented in Table 5-12.

TABLE 5-12. REMAINING NO_X CONTROL TECHNOLOGIES

Rank	Control Technology	Potential Control Efficiency (%)
1	SCR	70-90%
2	SNCR	65-75%
3	Good Combustion Practices	Base Case

5.15.5 EVALUATION OF MOST STRINGENT CONTROLS (STEP 4)

The fourth of the five steps in the top-down BACT assessment procedure is to evaluate the most effective control and document the results. This has been performed for the remaining control technologies on the basis of economic, energy, and environmental considerations, and is described below.

5.15.5.1 TAIL END SCR/RSCR

As described earlier, a SCR or RSCR works by reheating the flue gas to the necessary temperatures for the ammonia and NO_X to react to form nitrogen and water.

The cost of using an SCR system to control NO_X emissions for the facility natural gas boilers exceeds the benefit of the reduction it offers. The current cost of controlling NO_X with an SCR system is conservatively estimated at approximately $13,000 per ton of NO_X reduced. Energy and environmental related impacts would involve the increased use of natural gas, leading to emissions of additional pollutants such as NO_X, as well as additional toxic emissions resultant from the use of ammonia.

PyraMax has determined that an SCR/RSCR system is not BACT based on the environmental, energy, and economic analyses. Detailed cost calculations can be found in Appendix D.

5.15.5.2 SNCR

SNCR has not been utilized on any boilers under 100 MMBtu/hr according to RBLC entries. SNCR systems are generally thought to have a NO_X reduction efficiency of 65 to 75%.

PyraMax evaluated the environmental, energy, and economic impacts of using an SNCR. The cost of using an SNCR system to control NO_X emissions for the facility natural gas boilers exceeds the benefit of the reduction it offers. The current cost of controlling NO_X with an SNCR system is conservatively estimated at approximately $15,000 per ton of NO_X reduced. Environmental related impacts would involve the increased use of natural gas, leading to emissions of additional pollutants such as NO_X, as well as additional toxic emissions resultant from the use of ammonia.

PyraMax has determined that a SNCR is not BACT based on the low NO_X control the technology offers. Detailed cost calculations can be found in Appendix D.

5.15.5.3 GOOD DESIGN AND OPERATING PRACTICES

Since good design and operation is not an exhaust stream control technique, no adverse environmental, energy or economic impacts are associated with this technique. Good design includes low NO_X burners and proper operation of the boilers to reduce NO_X formation. As such, PyraMax has determined that good design and operating practices and use of low NO_X burners is BACT for the boilers for NO_X emissions.

5.15.6 SELECTION OF BACT (STEP 5)

Based on the previous analyses, PyraMax has determined that good design and operating practice is BACT for the proposed boilers, involving use of low NO_X burners.

Therefore, BACT is proposed as the use of low NO_X burners in conjunction with use of natural gas fuel and propane as a backup fuel. Compliance will be demonstrated through maintenance of facility fuel usage records.

5.16 BOILER – SO_2 BACT

5.16.1 BACKGROUND ON POLLUTANT FORMATION

SO_2 emissions result from the oxidation of sulfur in the fuel during the combustion process. Fuel based SO_2 emissions almost entirely depend upon the sulfur content of the fuel and are not dependent upon boiler properties. Since the fuel fired is natural gas with propane as a backup, almost all of the sulfur released is in the form of SO_2. Also, SO_2 emissions from the boiler are minimal (< 0.1 tpy) based on the sulfur content of natural gas/propane.

5.16.2 IDENTIFICATION OF POTENTIAL CONTROL TECHNIQUES (STEP 1)

Candidate control options identified from the RBLC search and the literature review include those classified as pollution reduction techniques. SO_2 reduction options include:

- Wet Scrubber
- Dry or Semi-Dry Scrubber
- Sorbent Injection

These control technologies were briefly discussed in Sections 6.6.2.1 through 6.6.2.3

5.16.3 ELIMINATION OF TECHNICALLY INFEASIBLE CONTROL OPTIONS (STEP 2)

After the identification of control options, the second step in the BACT assessment is to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that would prohibit the implementation of the control or if the highest control efficiency of the option would result in an emission level that is higher than any applicable regulatory limits. All previously identified control technologies are technically feasible.

5.16.4 RANK OF REMAINING CONTROL TECHNOLOGIES (STEP 3)

The third of the five steps in the top-down BACT assessment procedure is to rank technically feasible control technologies by control effectiveness. The remaining control technologies are presented in Table 5-13.

TABLE 5-13. REMAINING SO_2 CONTROL TECHNOLOGIES

Rank	Control Technology	Potential Control Efficiency (%)
1	Wet Scrubber	90-98%
2	Dry or Semi-Dry Scrubber	80-90%
3	Sorbent Injection	50-60%

5.16.5 EVALUATION OF MOST STRINGENT CONTROLS (STEP 4)

The fourth of the five steps in the top-down BACT assessment procedure is to evaluate the most effective control and document the results. This has been performed for the remaining control technologies on the basis of economic, energy, and environmental considerations, and is described below.

5.16.5.1 SORBENT INJECTION

As described earlier, the sorbent injection system uses dry calcium or sodium-based sorbent in conjunction with a baghouse.

Uncontrolled emissions of SO_2 emissions from the boilers are resultant from combustion of natural gas/propane, and are estimated at approximately 0.03 tpy. Assuming complete removal of SO_2 emissions, the annualized control cost for sorbent injection would only need to be $300 to exceed a cost effectiveness of $10,000 per ton. As the annualized operating costs associated with such a unit would likely exceed such a figure by $300 alone, sorbent injection would not be considered economically feasible for control of SO_2 emissions due to the very small amount of SO_2 emissions estimated from the boilers. There would also be associated energy impacts related to operation of the sorbent injection equipment.

Based on the environmental, energy, and economic analyses, PyraMax has determined that sorbent injection is not BACT for the boilers due to the minimal amount of SO_2 generated as part of the process.

5.16.5.2 WET SCRUBBER

As discussed earlier, wet scrubber systems are anticipated to reduce SO_2 outlet emissions from the proposed pelletizers by 90%. The capital and overall costs of a wet scrubber on a pelletizer are expected to be quite high relative to other sulfur control options.

Uncontrolled emissions of SO_2 emissions from the boilers are resultant from combustion of natural gas/propane, and are estimated at approximately 0.03 tpy. Assuming complete removal of SO_2 emissions, the annualized control cost for a wet scrubber would only need to be \$300 to exceed a cost effectiveness of \$10,000 per ton. As the annualized operating costs associated with such a unit would likely exceed such a figure by \$300 alone, use of a wet scrubber would not be considered economically feasible for control of SO_2 emissions due to the very small amount of SO_2 emissions estimated from the boilers. There would also be associated energy impacts related to operation of the wet scrubber equipment (system pumps), as well as environmental impacts associated with wastewater treatment and disposal.

Based on the environmental, energy, and economic analyses, PyraMax determined that a wet scrubber is not BACT for reducing SO_2 emissions from the proposed boilers.

5.16.5.3 DRY OR SEMI-DRY SCRUBBER

Uncontrolled emissions of SO_2 emissions from the boilers are resultant from combustion of natural gas/propane, and are estimated at approximately 0.03 tpy. Assuming complete removal of SO_2 emissions, the annualized control cost for a dry scrubber would only need to be \$300 to exceed a cost effectiveness of \$10,000 per ton. As the annualized operating costs associated with such a unit would likely exceed such a figure by \$300 alone, use of a dry scrubber would not be considered economically feasible for control of SO_2 emissions due to the very small amount of SO_2 emissions estimated from the boilers. There would also be associated energy impacts related to operation of the equipment (system pressure drop).

Based on the environmental, energy, and economic analyses, PyraMax determined that a dry scrubber is not BACT for reducing SO_2 emissions from the proposed boilers.

5.16.6 SELECTION OF BACT (STEP 5)

Based on the previous analyses, PyraMax has determined that none of the systems are BACT for the proposed boilers. Usage of natural gas (with propane as a backup) in the boiler can be considered as the best option for control of SO_2 since the fuel has the least amount of sulfur in it as compared to fuel oil or coal. Hence, firing natural gas or propane in the boilers is BACT for SO_2. Compliance will be demonstrated through maintenance of facility fuel usage records.

5.17 BOILER – CO BACT

5.17.1 BACKGROUND ON POLLUTANT FORMATION

CO emissions from the boilers are entirely from the incomplete combustion of carbon in the fuel. Conditions leading to incomplete combustion include the following: insufficient oxygen availability, poor fuel/air mixing, reduced combustion temperature, reduced combustion gas residence time, and load reduction. In addition, combustion modifications taken to reduce NO_X emissions may result in increased CO emissions.

5.17.2 IDENTIFICATION OF POTENTIAL CONTROL TECHNIQUES (STEP 1)

Candidate control options identified from the RBLC search and the literature review include those classified as pollution reduction techniques. CO reduction options include:

- Regenerative Thermal Oxidizer (RTO)
- Oxidation Catalyst
- Good combustion techniques

These control technologies were briefly discussed in Sections 6.7.2.1 and 6.7.2.2.

5.17.3 ELIMINATION OF TECHNICALLY INFEASIBLE CONTROL OPTIONS (STEP 2)

After the identification of control options, the second step in the BACT assessment is to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that would prohibit the implementation of the control or if the highest control efficiency of the option would result in an emission level that is higher than any applicable regulatory limits. All previously identified control technologies are technically feasible.

5.17.4 RANK OF REMAINING CONTROL TECHNOLOGIES (STEP 3)

The third of the five steps in the top-down BACT assessment procedure is to rank technically feasible control technologies by control effectiveness. The remaining control technologies are presented in Table 5-14.

TABLE 5-14. REMAINING CO CONTROL TECHNOLOGIES

Rank	Control Technology	Potential Control Efficiency (%)
1	RTO	98%
2	Oxidation Catalyst - with reheat	95%
5	Good Combustion Practices	Base Case

5.17.5 EVALUATION OF MOST STRINGENT CONTROLS (STEP 4)

The fourth of the five steps in the top-down BACT assessment procedure is to evaluate the most effective control and document the results. This has been performed for the remaining control technologies on the basis of economic, energy, and environmental considerations, and is described below.

5.17.5.1 REGENERATIVE THERMAL OXIDIZER

The cost of using an RTO on the boilers exceeds the benefit of the CO reduction it offers. The current cost of controlling CO with a RTO system is estimated at approximately $250,000 per ton of CO reduced. There would also be associated energy and environmental impacts resultant from use of the natural gas, including additional pollutant emissions such as NO_X emissions from natural gas combustion.

PyraMax has determined that an RTO is not BACT for the boilers based on the environmental, energy and economic analyses. Detailed cost calculations can be found in Appendix D.

5.17.5.2 OXIDATION CATALYST

The oxidation catalyst must be installed downstream of the particulate control device to ensure that the catalyst is not chemically damaged. However, significant auxiliary fuel input will be required to raise the temperature of the flue gas.

The cost of using an oxidation catalyst on the boilers exceeds the benefit of the CO reduction it offers. The current cost of controlling CO with an oxidation catalyst system is estimated at approximately $144,000 per ton of CO reduced. There would also be associated energy and environmental impacts resultant from use of the natural gas for the reheat process, including additional pollutant emissions such as NO_X emissions from natural gas combustion.

Hence, PyraMax has determined that an oxidation catalyst is not BACT for the boilers based on the environmental, energy, and economic analyses. Detailed cost calculations can be found in Appendix D.

5.17.5.3 GOOD COMBUSTION TECHNIQUES

The only remaining technology is good design and operating practices (good combustion practices), a logical option since a properly designed and operated boiler can effectively minimize CO formation. This is done by ensuring a good design of the boiler that promotes complete combustion. Good design and operating practices is considered BACT for CO for the boilers.

5.17.6 SELECTION OF BACT (STEP 5)

Based on the previous analyses, PyraMax has determined that employing good combustion technique is BACT for the proposed boilers. There are no negative environmental and energy impacts associated with this option. In addition, the RBLC entries prove that good combustion techniques are widely accepted as BACT for boilers. Compliance will be demonstrated through maintenance of facility fuel usage records.

5.18 BOILER – PM/PM_{10}/$PM_{2.5}$ BACT

5.18.1 BACKGROUND ON POLLUTANT FORMATION

PM/PM_{10}/$PM_{2.5}$ emissions from the boiler are primarily generated from the combustion of natural gas. The boilers are point sources of particulate emissions.

5.18.2 IDENTIFICATION OF POTENTIAL CONTROL TECHNIQUES (STEP 1)

Candidate control options identified from the RBLC search and the literature review include those classified as pollution reduction techniques. Application of a control technology differs for point sources and fugitive sources. PM reduction options from point sources include:

- Baghouse
- Electrostatic Precipitator (ESP)
- Wet Scrubbing
- Venturi Scrubber

These control technologies were briefly discussed in Sections 6.8.2.1 through 6.8.2.4.

5.18.3 ELIMINATION OF TECHNICALLY INFEASIBLE CONTROL OPTIONS (STEP 2)

After the identification of control options, the second step in the BACT assessment is to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that would prohibit the implementation of the control or if the highest control efficiency of the option would result in an emission level that is higher than any applicable regulatory limits. All of the above mentioned options are technically feasible for control of PM from the boilers.

5.18.4 RANK OF REMAINING CONTROL TECHNOLOGIES (STEP 3)

The third of the five steps in the top-down BACT assessment procedure is to rank technically feasible control technologies by control effectiveness. The remaining control technologies are presented in Table 5-15.

TABLE 5-15. REMAINING PM/PM_{10}/$PM_{2.5}$ CONTROL TECHNOLOGIES

Rank	Control Technology	Potential Control Efficiency (%)
1	Baghouse and ESP	> 99%
2	Wet Scrubbing	< 99%
5	Venturi Scrubber	< 90%

5.18.5 EVALUATION OF MOST STRINGENT CONTROLS (STEP 4)

PyraMax has determined that using any of the control technologies discussed above do not result in cost effective control. The cost of installing and operating these technologies far exceeds the benefit it offers in control due to the low concentration PM stream generated from combustion of natural gas. Costs for control of PM emissions would easily exceed $500,000 per ton. As such, PyraMax has determined that exclusively burning natural gas or propane is BACT for the boilers.

5.18.6 SELECTION OF BACT (STEP 5)

As discussed above, PyraMax has determined that combusting relatively clean fuels such as natural gas or propane that do not result in high particulate emissions can be considered BACT for the proposed boilers. Compliance will be demonstrated through maintenance of facility fuel usage records.

5.19 BOILER - VOC BACT

5.19.1 BACKGROUND ON POLLUTANT FORMATION

VOC from the boilers are generated as a result of natural gas combustion. Carbon in the fuel that is not oxidized completely results in VOC formation.

5.19.2 IDENTIFICATION OF POTENTIAL CONTROL TECHNIQUES (STEP 1)

Candidate control options identified from the RBLC search and the literature review include those classified as pollution reduction techniques. VOC reduction options include:

- Regenerative Thermal Oxidizer (RTO)
- Oxidation Catalyst
- Good combustion techniques

These control technologies were briefly discussed in the Sections 6.7.2.1 and 6.7.2.2.

5.19.3 ELIMINATION OF TECHNICALLY INFEASIBLE CONTROL OPTIONS (STEP 2)

After the identification of control options, the second step in the BACT assessment is to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that would prohibit the implementation of the control or if the highest control efficiency of the option would result in an emission level that is higher than any applicable regulatory limits. All previously identified control technologies are feasible.

5.19.4 RANK OF REMAINING CONTROL TECHNOLOGIES (STEP 3)

The third of the five steps in the top-down BACT assessment procedure is to rank technically feasible control technologies by control effectiveness. The remaining control technologies are presented in Table 5-16.

TABLE 5-16. REMAINING VOC CONTROL TECHNOLOGIES

Rank	Control Technology	Potential Control Efficiency (%)
1	RTO	98%
2	Oxidation Catalyst - with reheat	95%
5	Good Combustion Practices	Base Case

5.19.5 EVALUATION OF MOST STRINGENT CONTROLS (STEP 4)

The fourth of the five steps in the top-down BACT assessment procedure is to evaluate the most effective control and document the results. PyraMax has determined that using any of the control technologies discussed above do not result in cost effective control. The cost of installing and operating these technologies far exceeds the benefit it offers in control due to the low concentration VOC stream generated from combustion of natural gas or propane. Costs for control of VOC emissions would easily exceed $1,000,000 per ton for these pollutants.

The only remaining technology is good design and operating practices (good combustion practices), a logical option since a properly designed and operated ceramic kiln can effectively minimize VOC formation. This is done by ensuring lower carbon content of the clay and good design of the kiln that promotes complete combustion. Good design and operating practices is considered BACT for VOC for the proposed kiln.

5.19.6 SELECTION OF BACT (STEP 5)

Based on the previous analyses, PyraMax has determined that employing good combustion technique is BACT for the proposed boilers. There are no negative environmental and energy impacts associated with this option. In addition, the RBLC search proves that good combustion techniques are widely accepted as BACT for boilers. Compliance will be demonstrated through maintenance of facility fuel usage records.

5.20 EMERGENCY GENERATOR - NO_X BACT

5.20.1 BACKGROUND ON POLLUTANT FORMATION

There are two generators to be installed, each rated at 670 hp. The generators are proposed to be diesel fired conforming to all requirements of NSPS Subpart IIII. NO_X from the generators are primarily due to thermal NO_X generation. NO_X formed in the high-temperature, post-flame region of the combustion equipment is "thermal NO_X." NO_X can also be formed as a result of fuel NO_X. "Fuel NO_X" forms when fuels containing nitrogen are burned. When these fuels are burned, the nitrogen bonds break and some of the resulting free nitrogen oxidizes to form NO_X. With excess air, the degree of fuel NO_X formation is primarily a function of the nitrogen content of the fuel.

5.20.2 IDENTIFICATION OF POTENTIAL CONTROL TECHNIQUES (STEP 1)

Candidate control options identified from the RBLC search and the literature review include those classified as pollution reduction techniques. NO_X reduction options include:

- Selective Non-Catalytic Reduction (SNCR)
- Selective Catalytic Reduction (SCR)
- Combustion Design Control

These control technologies were briefly discussed in Sections 6.5.2.2 through 6.5.2.4.

5.20.3 ELIMINATION OF TECHNICALLY INFEASIBLE CONTROL OPTIONS (STEP 2)

After the identification of control options, the second step in the BACT assessment is to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that would prohibit the implementation of the control or if the highest control efficiency of the option would result in an emission level that is higher than any applicable regulatory limits.

Applying SNCR to the generators at the facility may be challenging from an operations standpoint due to the varying conditions of the exhaust. The NO_X emission rate from the generators will vary during startup and depend upon the operating conditions of the engine. Under these conditions, an SNCR unit would not be capable of achieving steady-state operation and would pose adverse environmental impacts due to ammonia slip or urea release. Despite the technical concerns associated with operating a SNCR system, PyraMax considers SNCR to be a technically feasible control option.

Add-on controls such as SCR systems require fairly constant exhaust gas temperatures, and operation outside of the ideal range can result in increased emissions of NO_X and NH_3 due to ammonia slip. SCR may be difficult to use for sources that operate for short periods of time and that experience frequent starts/stops since it can take time for the exhaust stream to reach the required operating temperature range. Despite the technical concerns associated with operating a SCR system to reduce NO_X emissions from the generators, PyraMax considers SCR to be a technically feasible control option.

Combustion design controls are a technically feasible option for reducing NO_X emissions from compression ignition, internal combustion engine (CI ICE) .

5.20.4 RANK OF REMAINING CONTROL TECHNOLOGIES (STEP 3)

The third of the five steps in the top-down BACT assessment procedure is to rank technically feasible control technologies by control effectiveness. The remaining control technologies are presented in Table 5-17.

TABLE 5-17. REMAINING NO_X CONTROL TECHNOLOGIES

Rank	Control Technology	Potential Control Efficiency (%)
1	SCR	70-90%
2	SNCR	65-75%
3	Good Combustion Practices	Base Case

5.20.5 EVALUATION OF MOST STRINGENT CONTROLS (STEP 4)

The fourth of the five steps in the top-down BACT assessment procedure is to evaluate the most effective control and document the results. This has been performed for the remaining control technologies on the basis of economic, energy, and environmental considerations, and is described below.

As previously stated, EPA determined in the development of NSPS Subpart IIII that add-on controls are economically infeasible for emergency ICE. Based on EPA's economic analysis, PyraMax has determined that SCR and SNCR are not BACT for NO_X emissions from the generators.

With all add-on NO_X control options eliminated, combustion design controls, the top and only remaining available and technically feasible NO_X control option, will be applied to achieve compliance with the proposed BACT limits.

5.20.6 SELECTION OF BACT (STEP 5)

PyraMax proposes a combined BACT emission limit for NO_X and non-methane hydrocarbon (NMHC) for the generator equal to that of the applicable NSPS Subpart IIII standard, or 4 g/kW-hr.

To comply with the proposed BACT limits, PyraMax will purchase generators certified by the manufacturer to meet these emissions levels. Operation of the generators for the purposes of maintenance checks and readiness testing will be limited to 100 hours per year and the total annual hours of operation including emergency use will also be limited to 100 hours per year. Based on review of the RBLC database, PyraMax believes that the proposed NO_X and NMHC BACT limits are consistent with the most stringent limits in the RBLC for comparable generators.

5.21 EMERGENCY GENERATOR – SO_2 BACT

5.21.1 BACKGROUND ON POLLUTANT FORMATION

SO_2 emissions result from the oxidation of sulfur in the fuel during the combustion process. Fuel based SO_2 emissions almost entirely depend upon the sulfur content of the fuel and are not dependent upon boiler properties. Due to requirements under NSPS Subpart IIII, the sulfur content in the fuel fired cannot exceed 15 ppm.

5.21.2 IDENTIFICATION OF POTENTIAL CONTROL TECHNIQUES (STEP 1)

Candidate control options identified from the RBLC search and the literature review include those classified as pollution reduction techniques. SO_2 reduction options include:

- ▲ Wet Scrubber
- ▲ Dry or Semi-Dry Scrubber
- ▲ Sorbent Injection

These control technologies were briefly discussed in Sections 6.6.2.1 through 6.6.2.3.

5.21.3 ELIMINATION OF TECHNICALLY INFEASIBLE CONTROL OPTIONS (STEP 2)

After the identification of control options, the second step in the BACT assessment is to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that would prohibit the implementation of the control or if the highest control efficiency of the option would result in an emission level that is higher than any applicable regulatory limits.

All three add-on controls described above require fairly constant exhaust gas temperatures, and operation outside of the ideal range will not result in effectively controlled SO_2 emissions. They may be difficult to use for sources that operate for short periods of time and that experience frequent starts/stops since it can take time for the exhaust stream to reach the required operating temperature range. Despite the technical concerns associated with operating these systems to reduce SO_2 emissions from the generators, PyraMax considers them to be technically feasible control options.

5.21.4 RANK OF REMAINING CONTROL TECHNOLOGIES (STEP 3)

The third of the five steps in the top-down BACT assessment procedure is to rank technically feasible control technologies by control effectiveness. The remaining control technologies are presented in Table 5-18.

TABLE 5-18. REMAINING SO_2 CONTROL TECHNOLOGIES

Rank	Control Technology	Potential Control Efficiency (%)
1	Wet Scrubber	90-98%
2	Dry or Semi-Dry Scrubber	80-90%
3	Sorbent Injection	50-60%

5.21.5 EVALUATION OF MOST STRINGENT CONTROLS (STEP 4)

The fourth of the five steps in the top-down BACT assessment procedure is to evaluate the most effective control and document the results. This has been performed for the remaining control technologies on the basis of economic, energy, and environmental considerations, and is described below.

As previously stated, EPA determined in the development of NSPS Subpart IIII that add-on controls are economically infeasible for emergency ICE. Based on EPA's economic analysis, PyraMax has determined that none of the above control technologies are BACT for SO_2 emissions from the generators.

With all add-on SO_2 control options eliminated, using ultra low sulfur diesel with sulfur content of 15 ppm is considered BACT for SO_2.

5.21.6 SELECTION OF BACT (STEP 5)

Based on the previous analyses, PyraMax has determined that none of the systems are BACT for the proposed generators. Since SO_2 is only generated from the sulfur content of the fuel, limiting sulfur to 15 ppm will limit SO_2 emissions from the generators.

In addition, operation of the generators for the purposes of maintenance checks and readiness testing will be limited to 100 hours per year and the total annual hours of operation including emergency use will also be limited to 100 hours per year. Compliance can be demonstrated through fuel certification records of fuel type obtained.

5.22 EMERGENCY GENERATOR – CO BACT

5.22.1 BACKGROUND ON POLLUTANT FORMATION

CO from the generators are entirely from the incomplete combustion of carbon in the fuel. Conditions leading to incomplete combustion include the following: insufficient oxygen availability, poor fuel/air mixing, reduced combustion temperature, reduced combustion gas residence time, and load reduction. In addition, combustion modifications taken to reduce NO_X emissions may result in increased CO emissions.

5.22.2 IDENTIFICATION OF POTENTIAL CONTROL TECHNIQUES (STEP 1)

Candidate control options identified from the RBLC search and the literature review include those classified as pollution reduction techniques. CO reduction options include:

- Regenerative Thermal Oxidizer (RTO)
- Oxidation Catalyst
- Good combustion techniques

These control technologies were briefly discussed in Sections 6.7.2.1 through 6.7.2.2.

5.22.3 ELIMINATION OF TECHNICALLY INFEASIBLE CONTROL OPTIONS (STEP 2)

Although thermal or catalytic oxidation are technically feasible, these technologies may not provide consistent CO control efficiencies and may be difficult to operate when used to reduce CO emissions from sources that operate for short periods of time and that experience frequent starts/stops. Since it can take time for the exhaust stream to reach the required operating temperature range for efficient oxidation, the CO control efficiency of thermal or catalytic oxidation for a generator is lower than for a unit that runs at steady-state. Except for emergencies, the generator will normally only be operated for readiness testing.

Good combustion design controls are a technically feasible control option for reducing CO emissions from ICEs.

5.22.4 RANK OF REMAINING CONTROL TECHNOLOGIES (STEP 3)

The third of the five steps in the top-down BACT assessment procedure is to rank technically feasible control technologies by control effectiveness. The remaining control technologies are presented in Table 5-19.

TABLE 5-19. REMAINING CO CONTROL TECHNOLOGIES

Rank	Control Technology	Potential Control Efficiency (%)
1	RTO	98%
2	Oxidation Catalyst - with reheat	95%
5	Good Combustion Practices	Base Case

5.22.5 EVALUATION OF MOST STRINGENT CONTROLS (STEP 4)

The fourth of the five steps in the top-down BACT assessment procedure is to evaluate the most effective control and document the results.

As previously stated, EPA determined in the development of NSPS Subpart IIII that add-on controls are economically infeasible for emergency ICE. Based on EPA's economic analysis, PyraMax has determined that the top and only remaining available and technically feasible CO control option, combustion design controls, will be applied to achieve compliance with the proposed BACT limit.

5.22.6 SELECTION OF BACT (STEP 5)

PyraMax proposes CO BACT emission limits for the generators equal to that of the applicable NSPS Subpart IIII standard, or 3.5 g /kW-hr.[72]

To comply with the proposed BACT limit, PyraMax will purchase an ICE certified by the manufacturer to meet this emission level. Operation of the ICE for the purposes of maintenance checks and readiness testing (per recommendations from the government, manufacturer/vendor, or insurance) will be limited to 100 hours per year. Based on review of the RBLC database, PyraMax believes that the proposed CO BACT limits are consistent with the most stringent limits shown in the RBLC for comparable generators.

5.23 BOILER – PM/PM_{10}/$PM_{2.5}$ BACT

5.23.1 BACKGROUND ON POLLUTANT FORMATION

PM/PM_{10}/$PM_{2.5}$ emissions from the emergency generator are primarily generated from the combustion of fuel oil. The emissions from this source as limited per NSPS Subpart IIII. The generator is a point source of particulate emissions.

5.23.2 IDENTIFICATION OF POTENTIAL CONTROL TECHNIQUES (STEP 1)

Candidate control options identified from the RBLC search and the literature review include those classified as pollution reduction techniques. Application of a control technology differs for point sources and fugitive sources. PM reduction options from point sources include:

- Baghouse
- Electrostatic Precipitator (ESP)
- Wet Scrubbing

These control technologies were briefly discussed in Sections 6.8.2.1 through 6.8.2.3.

5.23.3 ELIMINATION OF TECHNICALLY INFEASIBLE CONTROL OPTIONS (STEP 2)

After the identification of control options, the second step in the BACT assessment is to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that would prohibit the implementation of the control or if the highest control efficiency of the option would result in an emission level that is higher than any applicable regulatory limits.

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[72] Pursuant to §60.4205(c), the fire pump engines (which have a displacement less than 30 liters per cylinder) are subject to the emission limits from Table 4 of Subpart IIII.

EPA determined in the development of NSPS Subpart IIII that add-on controls are economically infeasible for emergency ICE. However, all of the above mentioned options are technically feasible for control of PM from the generator.

5.23.4 RANK OF REMAINING CONTROL TECHNOLOGIES (STEP 3)

The third of the five steps in the top-down BACT assessment procedure is to rank technically feasible control technologies by control effectiveness. The remaining control technologies are presented in Table 5-20.

TABLE 5-20. REMAINING PM/PM_{10}/$PM_{2.5}$ CONTROL TECHNOLOGIES

Rank	Control Technology	Potential Control Efficiency (%)
1	Baghouse and ESP	> 99%
2	Wet Scrubbing	< 99%

5.23.5 EVALUATION OF MOST STRINGENT CONTROLS (STEP 4)

PyraMax has determined that using any of the control technologies discussed above do not result in cost effective control as discussed by EPA. The cost of installing and operating these technologies far exceeds the benefit it offers in control due to the intermittent operation of the source. Limiting the generator to operating a maximum of 100 hours per year and the use of only low sulfur diesel is considered BACT for the generators.

5.23.6 SELECTION OF BACT (STEP 5)

As discussed above, PyraMax has determined that combusting only ultra low sulfur diesel for a maximum of 100 hours per year is BACT for the proposed generators.

5.24 EMERGENCY GENERATOR - VOC BACT

5.24.1 BACKGROUND ON POLLUTANT FORMATION

VOC from the generator is generated as a result of diesel combustion. Carbon in the fuel that is not oxidized completely results in VOC formation.

5.24.2 IDENTIFICATION OF POTENTIAL CONTROL TECHNIQUES (STEP 1)

Candidate control options identified from the RBLC search and the literature review include those classified as pollution reduction techniques. VOC reduction options include:

- Regenerative Thermal Oxidizer (RTO)
- Oxidation Catalyst
- Good combustion techniques

These control technologies were briefly discussed in the Sections 6.7.2.1 and 6.7.2.2.

5.24.3 ELIMINATION OF TECHNICALLY INFEASIBLE CONTROL OPTIONS (STEP 2)

After the identification of control options, the second step in the BACT assessment is to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that would prohibit the implementation of the control or if the highest control efficiency of the option would result in an emission level that is higher than any applicable regulatory limits.

Although thermal or catalytic oxidation are technically feasible, these technologies may not provide consistent VOC control efficiencies and may be difficult to operate when used to reduce VOC emissions from sources that operate for short periods of time and that experience frequent starts/stops. Since it can take time for the exhaust stream to reach the required operating temperature range for efficient oxidation, the VOC control efficiency of thermal or catalytic oxidation for a generator is lower than for a unit that runs at steady-state. Except for emergencies, the generator will normally only be operated for readiness testing.

5.24.4 RANK OF REMAINING CONTROL TECHNOLOGIES (STEP 3)

The third of the five steps in the top-down BACT assessment procedure is to rank technically feasible control technologies by control effectiveness. The remaining control technologies are presented in Table 5-21.

TABLE 5-21. REMAINING VOC CONTROL TECHNOLOGIES

Rank	Control Technology	Potential Control Efficiency (%)
1	RTO	98%
2	Oxidation Catalyst - with reheat	95%
5	Good Combustion Practices	Base Case

5.24.5 EVALUATION OF MOST STRINGENT CONTROLS (STEP 4)

The fourth of the five steps in the top-down BACT assessment procedure is to evaluate the most effective control and document the results.

As previously stated, EPA determined in the development of NSPS Subpart IIII that add-on controls are economically infeasible for emergency ICE. Based on EPA’s economic analysis, Pyramax has determined that the top and only remaining available and technically feasible CO control option, combustion design controls, will be applied to achieve compliance with the proposed BACT limit.

5.24.6 SELECTION OF BACT (STEP 5)

As discussed above, PyraMax proposes a combined BACT emission limit for NO_X and non-methane hydrocarbon (NMHC) for the generator equal to that of the applicable NSPS Subpart IIII standard, or 4 g/kW-hr.

To comply with the proposed BACT limits, PyraMax will purchase generators certified by the manufacturer to meet these emissions levels. Operation of the generators for the purposes of maintenance checks and readiness testing will be limited to 100 hours per year and the total annual hours of operation including emergency use will also be limited to 100 hours per year. Based on review of the RBLC database, PyraMax believes that the proposed NO_X and NMHC BACT limits are consistent with the most stringent limits in the RBLC for comparable generators.

5.25 MATERIAL HANDLING – $PM/PM_{10}/PM_{2.5}$ BACT

5.25.1 BACKGROUND ON POLLUTANT FORMATION

There are multiple proposed material handling sources such as bin vent filters for silos, baghouses for silo loadout operations, and potential fugitive sources such as material shredder, conveyors, etc. that result in $PM/PM_{10}/PM_{2.5}$ emissions. Handling of the clay can result in particulates that can become airborne.

5.25.2 IDENTIFICATION OF POTENTIAL CONTROL TECHNIQUES (STEP 1)

Candidate control options identified from the RBLC search and the literature review include those classified as pollution reduction techniques. Application of a control technology differs for point sources and fugitive sources. PM reduction options from point sources include:

- ▲ Baghouse
- ▲ Electrostatic Precipitator (ESP)
- ▲ Venturi Scrubber

PM reduction options from fugitive sources include:

- ▲ Water Application/Sweeping

These control technologies are briefly discussed in Sections 6.8.2.1 through 6.8.2.4. In addition, Water Application is discussed below.

5.25.2.1 WATER APPLICATION

Water spray could be used to suppress $PM/PM_{10}/PM_{2.5}$ emissions. Water sprays reduce the $PM/PM_{10}/PM_{2.5}$ emissions either by direct contact between the particles within the air and spray droplets or by binding the smaller particles to the surface of the material. However, clay can become very slick when wet and make travelling across wet surfaces dangerous. A regular schedule of sweeping the facility could also be implemented to reduce buildup of dust at the facility.

5.25.3 ELIMINATION OF TECHNICALLY INFEASIBLE CONTROL OPTIONS (STEP 2)

After the identification of control options, the second step in the BACT assessment is to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that would prohibit the implementation of the control or if the highest control efficiency of the option would result in an emission level that is higher than any applicable regulatory limits. All of the above mentioned options are technically feasible for control of PM from material handling.

5.25.4 RANK OF REMAINING CONTROL TECHNOLOGIES (STEP 3)

The third of the five steps in the top-down BACT assessment procedure is to rank technically feasible control technologies by control effectiveness. For emissions from point sources, the highest control is offered by baghouses with control efficiencies of 99% or greater. For emissions from fugitive sources, baghouses, ESPs and scrubbers are not appropriate. Hence, fugitive dust controls would offer the highest control for fugitive sources.

5.25.5 EVALUATION OF MOST STRINGENT CONTROLS (STEP 4)

PyraMax has determined that using the top control technology for each point or fugitive source is BACT. Baghouses will be installed at every point source of emissions and fugitive dust controls will be employed at every fugitive source of emissions.

5.25.6 SELECTION OF BACT (STEP 5)

Since baghouses offer the highest control of PM emissions and are widely accepted as BACT for control of PM emissions from point sources, PyraMax has determined that the baghouses are BACT for the proposed material handling equipment. Similarly, since water control cannot be employed on clay fugitive emissions due to safety concerns, other fugitive dust controls are considered BACT for control of PM emissions from fugitive sources. A PM BACT emission limit of 0.005 gr/dscf is proposed for the facility point sources from material handling and processing operations. Compliance will be demonstrated based on manufacturer guarantees for the individual pieces of equipment.

5.26 GHG BACT ASSESSMENT

Emissions increases from the proposed facility are subject to regulation under PSD and exceed the major source threshold. Therefore, a BACT analysis for GHG is being conducted on units that generate GHG. In the proposed plant, GHG are emitted from the following sources:

- Rotary kilns
- Pelletizer
- Boilers
- Emergency generators

Each of the units listed above generate GHG emissions from combustion. GHG emissions of CO_2, CH_4, and N_2O are anticipated as a result of the combustion processes. Additional sources of GHG include CO_2 emissions from sorbent injection in the control device and from carbon liberated from the raw material in the kiln; therefore, a BACT review must be conducted for each of these pollutants.[73] The following sections outline Steps 1 through 5 of the BACT analysis for CO_2, CH_4 and N_2O for the units identified.

U.S. EPA has issued several new guidance documents related to the completion of GHG BACT analyses. The following guidance documents were utilized as resources in completing the GHG BACT evaluation for the proposed project:

- ▲ *PSD and Title V Permitting Guidance For Greenhouse Gases* (hereafter referred to as General GHG Permitting Guidance)[74]
- ▲ *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Portland Cement Industry* (hereafter referred to as GHG BACT Guidance for the Portland Cement Industry)[75]
- ▲ *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Industrial, Commercial, and Institutional Boiler* (hereafter referred to as GHG BACT Guidance for Boilers)[76]

To complete the GHG BACT evaluation, PyraMax also relied on additional resources such as:

- ▲ RBLC database – Searching the newly enhanced RBLC database returned no results on permitting decisions for internal combustion engines in Process Code 17.000, gas boilers in Process Code 13.310, or kilns or pelletizers located within Process Code 90.017 (Calciners & Dryers and Mineral Processing Facilities), Process Code 90.008 (Clay and Fly Ash Sintering), and Process Code 90.009 (Clay Products including Brick & Ceramics) for GHGs.[77]

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[73] PyraMax will inject an alkaline sorbent such as sodium bicarbonate into kiln flue gas stream as part of a sorbent injection system for acid gas control. Due to the sorbent used, there will be resultant CO_2 emissions from this process. PyraMax estimated CO_2 emissions from sodium bicarbonate usage at 3,078 tpy. Since there are no substitute compounds that are non-carbonates and given the low magnitude of sorbent related CO_2 emissions relative to overall emissions, PyraMax is not considering alternatives in this BACT analysis.

[74] U.S. EPA, Office of Air and Radiation, Office of Air Quality Planning and Standards, (Research Triangle Park, NC: March 2011). http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf

[75] U.S. EPA, Office of Air and Radiation, Office of Air Quality Planning and Standards, (Research Triangle Park, NC: October 2010). http://www.epa.gov/nsr/ghgdocs/cement.pdf. Although the kaolin processing industry differs from the Portland cement industry, this document was reviewed for similarities in the processes (e.g., kiln operation).

[76] U.S. EPA, Office of Air and Radiation, Office of Air Quality Planning and Standards, (Research Triangle Park, NC: October 2010). http://www.epa.gov/nsr/ghgdocs/iciboilers.pdf.

[77] http://cfpub.epa.gov/RBLC/.

- GHG Mitigation Strategies Database – The GHG Mitigation Strategies Database did not contain any information for clay processing operations. The only comparable process industry is the Portland cement industry.[78]

5.27 ROTARY KILNS – CO_2 BACT

5.27.1 IDENTIFICATION OF POTENTIAL CO_2 CONTROL TECHNIQUES (STEP 1)

The following potential CO_2 control strategies for the rotary kilns were considered as part of this BACT analysis:

- Carbon capture and storage (CCS)
- Selection of the most efficient rotary kiln technology
- Selection of the lowest carbon fuel
- Installation of energy efficient options for the rotary kilns

5.27.1.1 CARBON CAPTURE AND STORAGE

Carbon capture and storage (CCS) involves separation and capture of CO_2 emissions from the flue gas, pressurization of the captured CO_2, transportation of the pressurized CO_2 via pipeline, and finally injection and long-term geologic storage of the captured CO_2. Several different technologies have demonstrated the potential to separate and capture CO_2. To date, some of these technologies have been demonstrated at the laboratory scale only, while others have been proven effective at the slip-stream or pilot-scale. Numerous projects are currently planned for the full-scale demonstration of CCS technologies.

According to the recently issued U.S. EPA guidance for PSD and Title V Permitting of Greenhouse Gases:

> *"For the purposes of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology that is "available" for facilities emitting CO_2 in large amounts, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO_2 streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing).[79]"*

It should be noted that the "high purity CO_2 stream emitting sectors" identified in the guidance document do not include either the clay mineral processing industry or boilers of the size and nature proposed by PyraMax.

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[78] http://ghg.ie.unc.edu:8080/GHGMDB/.

[79] US EPA, Office of Air Quality Planning and Standards, "PSD and Title V Permitting Guidance for Greenhouse Gases", March 2011, p. 32.

In addition to the U.S. EPA permitting guidance for GHG, white papers for GHG reduction options were reviewed for discussion of CCS technologies. In the GHG BACT Guidance for Boilers white paper, a brief overview of the CCS process is provided and the guidance cites the Interagency Task Force on Carbon Capture and Storage for the current development status of CCS technologies, which is further discussed in this section.[80,81]

In addition, in the GHG BACT Guidance for Portland Cement Industry white paper, CCS is identified as an available or emerging BACT option for process emission sources in the Portland cement industry.[82] However, cement production utilizes limestone as a raw material, the processing of which drives off CO_2 from the calcium carbonate ($CaCO_3$) in the limestone to form CaO (approximately 63.5% of cement) and comprise approximately 50% of the GHG emissions from the process.[83] By contrast, the carbon content of the clay raw material in the proposed process is less than 1% and CO_2 emissions from the raw material comprise approximately 10% of overall GHG emissions. Therefore, the magnitude of CO_2 emissions for the proposed process is much less than those from the Portland cement industry. As noted throughout the GHG BACT Guidance for Portland Cement Industry white paper, each CCS strategy discussed has technical feasibility concerns. As the proppant production industry is much smaller and emits much lower amounts of GHG emissions, the same technical challenges would remain.

In the aforementioned Interagency Task Force report on CCS technologies, a number of pre and post combustion CCS projects are discussed in detail; however, many of these projects are in formative stages of development and are predominantly power plant demonstration projects (and mainly slip stream projects). Capture-only technologies are technically available; however, the limiting factor is typically the lack of a geologic formation or pipeline for the carbon to be permanently sequestered.

Beyond power plant CCS demonstration projects, the report also discusses three industrial CCS projects that are being pursued under the Industrial Carbon Capture and Storage (ICCS) program for the following companies/installations:

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[80] US EPA, “Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Industrial, Commercial and Institutional Boilers,” October 2010, p. 26, http://www.epa.gov/nsr/ghgdocs/iciboilers.pdf

[81] “Report of the Interagency Task Force on Carbon Capture and Sequestration,” August 2010. http://fossil.energy.gov/programs/sequestration/ccstf/CCSTaskForceReport2010.pdf.

[82] U.S. EPA, Office of Air and Radiation, Office of Air Quality Planning and Standards, (Research Triangle Park, NC: October 2010). http://www.epa.gov/nsr/ghgdocs/cement.pdf.

[83] U.S. EPA, AP-42, Section 11.6, Portland Cement Manufacturing, January 1995. http://www.epa.gov/ttn/chief/ap42/ch11/final/c11s06.pdf.

Leucadia Energy: a methanol plant in Louisiana where 4 million tonnes per year of CO_2 will be captured and used in an enhanced oil recovery (EOR) application.

Archer Daniels Midland: an ethanol plant in Illinois where 900,000 tonnes per year of CO_2 will be captured and stored in a saline formation directly below the plant site.

Air Products: a hydrogen-production facility in Texas where 900,000 tonnes per year of CO_2 will be captured and used in an EOR application.

At present, these industrial deployments were selected for funding in June 2010 and are moving onto a demonstration phase. Therefore, they are not yet demonstrated.

5.27.1.2 SELECTION OF THE MOST EFFICIENT KILN TECHNOLOGY

There are two options available for rotary kiln technology selection: wet-process kilns, where raw materials are fed into the kiln as a mixture with higher moisture contents, and dry-process kilns, where the materials are fed as a dry powder. Although wet process kilns require additional heat input to drive off the moisture in the mixture, and, thusly, have higher CO_2 emissions from fuel combustion, they produce a higher quality clay product.[84]

5.27.1.3 SELECTION OF THE LOWEST CARBON FUEL

For GHG BACT analyses, low-carbon intensity fuel selection is the primary control option that can be considered a lower emitting process. The rotary kilns will combust natural gas as a primary fuel with propane gas as the fuel fired during periods of interrupted natural gas supply. Natural gas is the lowest emitting GHG fuel on a direct carbon basis than all other fuels.

5.27.1.4 INSTALLATION OF ENERGY EFFICIENCY OPTIONS ON THE ROTARY KILNS

Operating practices that increase energy efficiency are a potential control option for improving the fuel efficiency of the rotary kilns and therefore, providing benefit with respect to GHG emissions.

In October 2010, the U.S. EPA provided a white paper that addresses control technologies, energy efficiency measures, and fuel switching options for the Portland cement industry. Although not the same industry, there are analogous operations that may benefit from technology transfer between the industries. These options primarily focus on improved process control and management

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[84] U.S. EPA, AP-42, Section 11.25, Clay Processing, January 1995. Page 11.25-2. http://www.epa.gov/ttn/chief/ap42/ch11/final/c11s25.pdf.

systems and are expected to be part of the design of new construction.[85] The energy efficiency options listed in the GHG BACT Guidance for the Portland cement industry, that can be translated to the clay processing industry, are:

Kiln maintenance

Kiln combustion system improvements

Kiln insulation

Waste heat recovery

Additionally, the General GHG Permitting Guidance references several energy efficiency benchmarking tools. These tools contain performance benchmarking information, and may be useful in considering energy efficient technologies and processes if the information is specific and relevant to the rotary kilns. The following tools were identified:

Energy Star – Energy Performance Indicators (EPIs)[86]

DOE Industrial Technologies Program (ITP)[87]

Lawrence Berkeley National Laboratory Industrial Energy Analysis Program[88]

European Union (EU) Energy Efficiency Benchmarks[89]

Of the sources identified, none had clay processing kiln benchmarking studies. However, ITP's Process heat strategy includes waste heat recovery, improved combustion efficiency, and advanced controls as best practices to improve the overall energy efficiency.[90] These strategies are employed as part of the project.

5.27.2 ELIMINATION OF TECHNICALLY INFEASIBLE CONTROL OPTIONS (STEP 2)

5.27.2.1 CARBON CAPTURE AND STORAGE

While potentially available for certain high purity CO_2 streams, CCS is technically infeasible for the rotary kilns for the following reasons:

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[85] U.S. EPA, Office of Air and Radiation, Office of Air Quality Planning and Standards, (Research Triangle Park, NC: October 2010). http://www.epa.gov/nsr/ghgdocs/cement.pdf , p. 19.

[86] http://www.energystar.gov/index.cfm?c=in_focus.bus_cement_manuf_focus .

[87] http://www1.eere.energy.gov/industry/combustion/.

[88] http://industrial-energy.lbl.gov/.

[89] http://ec.europa.eu/environment/climat/emission/benchmarking_en.htm.

[90] http://www1.eere.energy.gov/industry/bestpractices/pdfs/35876.pdf.

Capture and Compression

CO_2 capture is achieved by separating CO_2 from emission sources where it is then recovered in a concentrated stream that can be sequestered. In a post-combustion capture scenario (such as would be necessary for the capture of CO_2 from the rotary kilns), CO_2 is exhausted in the flue gas at atmospheric pressure and a low concentration. The post-combustion CO_2 capture scenario is problematic because the low pressure and dilute concentration means a high volume of gas needs to be treated. Additional challenges stem from the impurities in the flue gas that tend to negatively affect the ability to adsorb CO_2,[91] and the compression of CO_2 would require a substantial auxiliary power load, resulting in additional fuel consumption (and additional CO_2, CH_4, and N_2O emissions) to produce steam to regenerate the solvent and compressors to compress the CO_2 for transport.[92]

Sequestration - Lack of Sequestration Sink (Geologic or Pipeline)

While capture-only technologies may be available and demonstrated on pilot scales, a remaining hurdle is the availability of a mechanism (pipeline or geologic formation) to permanently sequester the captured gas. As shown in the Interagency Report, there is no existing pipeline available in Georgia for nearby CO_2 transport. The closest existing pipeline (partially completed with proposed extensions) is located hundreds of miles away in Mississippi and Louisiana.[93]

In 2009, the U.S. Department of Energy (DOE), National Energy Technology Laboratory granted the University of South Carolina funds for geologic characterization of the South Georgia Rift basin that extends from South Carolina into Georgia for CO_2 storage. This three year research period (ending in December of 2011) will begin with a geologic storage assessment and estimate of CO_2 storage capacity. Subsequent years of study will determine regional characterization of target CO_2 storage formation and finally site-specific characterization with installation of a test hole and evaluation of leakage pathways.[94,95] Therefore, for the purposes of BACT, carbon storage in the South Georgia Basin formation or any other candidate geologic

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[91] Carbon Sequestration - CO_2 Storage, U.S. Department of Energy http://www.netl.doe.gov/technologies/carbon_seq/core_rd/co2capture.html.

[92] U.S. EPA, Office of Air and Radiation, Office of Air Quality Planning and Standards, (Research Triangle Park, NC: October 2010) , p. 37. http://www.epa.gov/nsr/ghgdocs/cement.pdf.

[93] Report of the Interagency Task Force on Carbon Capture & Storage, August 2010, Appendix B-1.

[94] http://www.dnr.sc.gov/SCO2/images/SC%20Carbon%20Sequestration%20Project%20Summary.pdf .

[95] Geologic Characterization of the South Georgia Rift Basin For Source Proximal CO_2 Storage, October 2010, http://www.netl.doe.gov/publications/proceedings/10/rcsp/presentations/Thur%20am/Brian%20Dressel/Waddell.2010%20South%20Carolina%20Partnerships%20Meeting%20Presentatio.pdf.

sequestration site is not considered to be a technically feasible option for reducing CO_2 emissions from the rotary kilns at this time. Furthermore, even if there were a geologic formation for sequestration, CCS would be economically infeasible for this project.

Based on the aforementioned technical challenges with capture, compression and storage of CO_2, CCS as a combined technology is not considered technically feasible as BACT for reducing CO_2 emissions from the rotary kilns. Accordingly, CCS is eliminated as a potential control option in this BACT assessment for CO_2 emissions due to technical infeasibility.

5.27.2.2 SELECTION OF THE MOST EFFICIENT ROTARY KILN TECHNOLOGY

Each of the kiln technologies listed in Step 1 are technically feasible.

5.27.2.3 SELECTION OF THE LOWEST CARBON FUEL

Natural gas, the lowest carbon fuel, is a technically feasible option for CO_2 control of the rotary kiln.

The clay raw material contains less than 0.5 percent by weight (wt%) carbon. Therefore, reduction in carbon content in the naturally occurring clay is anticipated to be technically infeasible as the carbon content is already much lower than other mineral processing industries (limestone, cement, etc). Furthermore, carbon dioxide generated from oxidation of the carbon in the clay accounts for 2,700 tons of CO_2 (approximately 10% of the CO_2 emissions from the kilns). Therefore, even if additional reduction in the CO_2 emissions from a lower carbon content raw material were technically feasible, the reduction would be economically infeasible due to the low level of emissions that could potentially be reduced.

5.27.2.4 INSTALLATION OF ENERGY EFFICIENCY OPTIONS ON THE ROTARY KILNS

Each of the aforementioned energy efficiency options in Step 1 is technically feasible for CO_2 control of the rotary kilns, with the exception of replacement equipment as this is a new installation.

5.27.3 RANK OF REMAINING CONTROL TECHNOLOGIES (STEP 3)

Kiln technology selection, low carbon fuel selection, and installation of energy efficient options are the remaining technically feasible control options for minimizing CO_2 emissions from the rotary kilns. It is unclear which option has a more significant impact on emissions of CO_2 from the facility.

Use of a low carbon fuel and installation of energy efficient options in conjunction with the rotary kiln selection will be evaluated further in Step 4 of the BACT analysis.

5.27.4 EVALUATION OF MOST STRINGENT CONTROLS (STEP 4)

5.27.4.1 SELECTION OF THE MOST EFFICIENT ROTARY KILN TECHNOLOGY

PyraMax is required to make a high quality product for the proppant industry. Therefore, a wet process kiln is required. However, PyraMax will utilize a pelletizer to remove moisture from the raw material feed (rather than in the kiln), as well as produce the pellets for processing in the kiln. This design will allow for a drier raw material to be fed into the rotary kiln, thus reducing kiln CO_2 emissions due to reduced fuel consumption by approximating a dry kiln design.

Although the process to produce high quality proppant requires a pelletizer (approximately 75 MMBtu/hr total heat input, fired with natural gas) to drive off moisture, the raw material processing for the proposed operation will not require grinding mills and their associated heaters.

5.27.4.2 SELECTION OF THE LOWEST CARBON FUEL

Natural gas is the lowest emitting carbon fuel that could be relied upon for the proposed operation. Propane will be used as a backup fuel.

5.27.4.3 INSTALLATION OF ENERGY EFFICIENCY OPTIONS ON THE ROTARY KILNS

No adverse energy, environmental, or economic impacts are associated with kiln selection and most energy efficient operating practices for reducing CO_2 emissions from the rotary kilns. The environmental benefits include fuel savings and reduction of GHG emissions, as well as other criteria pollutant emissions, due to the efficiency gains.

Waste heat energy from the cooler will be routed through the kiln to provide additional heating of the material feed, thus reducing fuel consumption. There is an opportunity to install a heat recovery steam generator (HRSG) at the outlet of the control device for each kiln. The HRSG would eliminate one of the natural gas fueled boilers. However, the heat recovery steam generator is not economically feasible, as the cost of the heat recovery steam generator is excessive compared to the reduction on CO_2 emissions from the elimination of the small (9.8 MMBtu/hr) natural gas boiler).

5.27.5 SELECTION OF CO_2 BACT (STEP 5)

A proposed pelletizer/rotary kiln design is the best technology fit with PyraMax's proposed project since it produces the required quality. Additionally, selection of natural gas as a primary fuel (with propane as a backup fuel) results in the lowest CO_2 emissions from combustion.

Based on the top-down process described above for control of GHG from the rotary kilns, PyraMax is proposing that the firing of natural gas as the primary fuel source and the operation of several energy efficiency options constitutes BACT for the rotary kilns. These energy efficiency options are summarized in Table 5-22.

TABLE 5-22. SUMMARY OF ENERGY EFFICIENCY OPTIONS FOR THE ROTARY KILNS

Energy Efficiency Option	Features of Rotary Kilns
Kiln maintenance	This kiln and auxiliary equipment will be maintained per the kiln manufacturer's recommendations.
Kiln process control	The kiln will have instrumentation and control devices for monitoring and controlling combustion.
Optimized combustion	Combustion air and flue gas will be adjusted as necessary to optimize combustion efficiency and minimize excess air.
Improved kiln insulation	The new rotary kilns will be insulated to manufacturer's specifications to minimize heat loss. Additionally, the kiln will install manufacturer's specified refractory materials to retain heat within the kiln.
Cooler gas heat recovery	Air from the cooler will be routed through the kiln to recover energy from the cooler flue gases.

In order to construct a GHG BACT limitation, PyraMax consulted EPA's General GHG Permitting Guidance which states:

> *EPA encourages permitting authorities to consider establishing an output-based BACT emissions limit…wherever feasible and appropriate to ensure that BACT is complied with at all levels of operation.*[96]

Based on this guidance from U.S. EPA, PyraMax is proposing an output-based BACT limitation based on the ratio of CO_2e emissions per unit of product output generated by the proposed proppant manufacturing process. Therefore, this output-based limitation will take into account the efficiency benefits of the selection of kiln technology for the proposed kilns, as well as the energy efficiency operating practices that will be utilized. PyraMax proposes a CO_2e BACT emission limit of 0.218 lb CO_2e per lb cooler product on a 12-month rolling average basis from each rotary kiln. PyraMax derived the proposed BACT emission limit on the basis of fuel throughput, sorbent injection, and carbon content of the raw material.[97]

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[96] US EPA, Office of Air Quality Planning and Standards, "PSD and Title V Permitting Guidance for Greenhouse Gases", March 2011, p 46.

[97] As summarized in Appendix C, the limit is based on CO_{2e} emissions of 7,638 lb/hr for each kiln and a cooler product rate of 35,114 lb/hr.

Compliance with the proposed BACT limit will be demonstrated based on the annual CO_2 emissions data measured by the mass balance (raw material carbon and sorbent injection) as well as published emission factors for combustion from EPA's GHG Mandatory Reporting Rule (40 CFR 98 Subpart C) and annual proppant production rate measured and recorded. CH_4 and N_2O emissions will also be calculated and included towards the CO_2e limitation and are described in more detail in the following sections. With regard to this proposed GHG limitation and the new experience related to tracking GHG, the General GHG Permitting Guidance states,

> *Thus, where there is some reasonable uncertainty regarding performance of specified energy efficiency measures, or the combination of measures, the permit can be written to acknowledge that uncertainty. As in the past, based on the particular circumstances addressed in the permitting record, the permitting authority has the discretion to set a permit limit informed by engineering estimates, or to set permit conditions that make allowance for adjustments of the BACT limits based on operational experience.*[98]

Therefore, PyraMax requests that the permit include flexibility to revise this emission limit after a nominal startup period should additional information become available regarding the effects of energy efficient options on operational performance.

5.28 ROTARY KILN - CH_4 BACT

5.28.1 IDENTIFICATION OF POTENTIAL CONTROL TECHNIQUES (STEP 1)

Available control options for minimizing CH_4 emissions from the rotary kilns include selection of a high efficiency kiln and operating practices that promote energy efficiency to reduce fuel usage.

5.28.2 ELIMINATION OF TECHNICALLY INFEASIBLE CONTROL OPTIONS (STEP 2)

Kiln selection and energy efficient operating practices are the only technically feasible control options for reducing CH_4 emissions from the rotary kilns.

5.28.3 RANK OF REMAINING CONTROL TECHNOLOGIES (STEP 3)

High efficiency kiln selection and energy efficient operating practices are evaluated in the remaining steps of the CH_4 BACT analysis for the rotary kilns. It is unclear which option has a more significant impact on emissions of CH_4 from the facility; therefore, no ranking of control options is performed.

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[98] US EPA, Office of Air Quality Planning and Standards, "PSD and Title V Permitting Guidance for Greenhouse Gases", March 2011, p 32.

5.28.4 EVALUATION OF MOST STRINGENT CONTROLS (STEP 4)

The most efficient, technically feasible control options involve selection of a high efficiency kiln and use of energy efficient practices.

5.28.5 SELECTION OF CH_4 BACT (STEP 5)

PyraMax has selected the most efficient kiln to meet the project requirements and is implementing the energy efficiency efforts as described in Section 5.27.4.3. Through these efforts to maximize the unit's efficiency, CH_4 emissions from the rotary kilns are inherently reduced and kept to a minimum.

As described in Section 5.27.5 PyraMax proposes a CO_2e BACT emission limit of 0.218 lb CO_2e/ lb cooler product on a 12-month rolling average basis from the each rotary kiln. The CH_4 portion of the proposed CO_2e BACT limit will be calculated based on the emission factor per fuel type in Table C-2 to 40 CFR 98 Subpart C and the Global Warming Potential (GWP) of 21 (the current GWP per the version of 40 CFR 98 Subpart A).

As previously stated, PyraMax is requesting flexibility with respect to compliance demonstrations with the lb CO_2e per lb cooler product in the initial operating phase of the rotary kilns.

5.29 ROTARY KILNS - N_2O BACT

5.29.1 IDENTIFICATION OF POTENTIAL CONTROL TECHNIQUES (STEP 1)

N_2O catalysts have been used in nitric/adipic acid plant applications to minimize N_2O emissions.[99] Tailgas from the nitric acid production process is routed to a reactor vessel with a N_2O catalyst followed by ammonia injection and a NO_X catalyst.

High efficiency kiln technology selection and energy efficient operating practices are also available control technology options for N_2O reduction.

5.29.2 ELIMINATION OF TECHNICALLY INFEASIBLE CONTROL OPTIONS (STEP 2)

N_2O catalysts have not been used to control N_2O emissions in clay processing kiln applications as yet. In addition, the very low N_2O concentrations present in the PyraMax kiln exhaust stream would make installation of N_2O catalysts technically infeasible. In comparison, the application of a catalyst in the nitric acid industry sector has been effective due to the high (1,000-2,000 ppm) N_2O concentration in those exhaust streams. N_2O catalysts are eliminated as a technically feasible option for the proposed project.

With N_2O catalysts eliminated, efficient kiln technology selection and energy efficient operating practices are the only available and technically feasible control options for N_2O reduction from the rotary kilns.

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[99] http://www.catalysts.basf.com/Main/mediaroom/10years_worldscale_experience_in_reducing_nitrous_.be

5.29.3 RANK OF REMAINING CONTROL TECHNOLOGIES (STEP 3)

High efficiency kiln selection and energy efficient operating practices are evaluated in the remaining steps of the N_2O BACT analysis for the rotary kilns. It is unclear which option has a more significant impact on emissions of N_2O from the facility; therefore, no ranking of control options is performed.

5.29.4 EVALUATION OF MOST STRINGENT CONTROLS (STEP 4)

No adverse energy, environmental, or economic impacts are associated with kiln selection and energy efficient operating practices for reducing N_2O emissions from the rotary kilns.

5.29.5 SELECTION OF N_2O BACT (STEP 5)

PyraMax has selected the most efficient kiln to meet the project requirements and is implementing the energy efficiency efforts as described in Section 5.27.4.3. Through these efforts to maximize the unit's efficiency, N_2O emissions from the rotary kilns are inherently reduced and kept to a minimum.

As described in Section 5.27.5, PyraMax proposes a CO_2e BACT emission limit of 0.218 lb CO_2e/ lb cooler product on a 12-month rolling average basis from the each rotary kiln. The N_2O portion of the proposed CO_2e BACT limit will be calculated based on the emission factor per fuel type in Table C-2 to 40 CFR 98 Subpart C and the GWP of 310 (the current GWP per the version of 40 CFR 98 Subpart A).

As previously stated, PyraMax is requesting flexibility with respect to compliance demonstrations with the lb CO_2e per lb cooler product in the initial operating phase of the rotary kilns.

5.30 PELLETIZER – CO_2 BACT

5.30.1 IDENTIFICATION OF POTENTIAL CO_2 CONTROL TECHNIQUES (STEP 1)

The following potential CO_2 control strategies for the pelletizers were considered as part of this BACT analysis:

- Carbon capture and storage (discussed in Section 5.27.2.1 above)
- Selection of the most efficient pelletizer technology
- Selection of the lowest carbon fuel
- Installation of energy efficient options for the pelletizers

5.30.1.1 SELECTION OF THE MOST EFFICIENT PELLETIZER TECHNOLOGY

There is limited information available regarding the efficiencies of different types of pelletizers. However, it is in PyraMax's best interest from a fuel efficiency standpoint to implement an efficient pelletizer technology.

5.30.1.2 SELECTION OF THE LOWEST CARBON FUEL

For GHG BACT analyses, low-carbon intensity fuel selection is the primary control option that can be considered a lower emitting process. The pelletizer will combust natural gas as a primary fuel with propane gas as the fuel fired during periods of interrupted natural gas supply. Natural gas is the lowest emitting GHG fuel on a direct carbon basis than all other fuels.

5.30.1.3 INSTALLATION OF ENERGY EFFICIENCY OPTIONS ON THE PELLETIZER

Operating practices that increase energy efficiency are a potential control option for improving the fuel efficiency of the pelletizer and therefore, providing benefit with respect to GHG emissions.

In November 2010, the U.S. EPA provided a white paper that addresses control technologies, energy efficiency measures, and fuel switching options for industrial, commercial and institutional boilers. Although boilers are a different equipment design, some of the same principles can be used on the pelletizers. The energy efficiency options listed in the GHG BACT Guidance for the Boilers are:

Burner replacement (for existing units)

Maintenance

Process control and combustion optimization

Insulation

Additionally, the General GHG Permitting Guidance references several energy efficiency benchmarking tools. However, these are not specific and relevant to the pelletizers in the clay processing industry.

5.30.2 ELIMINATION OF TECHNICALLY INFEASIBLE CONTROL OPTIONS (STEP 2)

5.30.2.1 CARBON CAPTURE AND STORAGE

The levels of CO_2 emissions (both concentration in the flue gas and amount) from the pelletizer are approximately the same as the rotary kilns. Additionally, there is a large volume of water in the exhaust of the pelletizer due to the moisture being removed from the raw material. While potentially available for certain high purity CO_2 streams, CCS is technically infeasible for the pelletizer for the reasons discussed in Section 5.27.2.1 for the rotary kilns.

5.30.2.2 SELECTION OF THE MOST EFFICIENT SPRAY DRYER TECHNOLOGY

Due to the limited availability of pelletizer efficiency summaries, PyraMax cannot currently definitely differentiate between separate technologies. However, PyraMax will choose an efficient pelletizer that can meet the design specifications for the proposed process.

5.30.2.3 SELECTION OF THE LOWEST CARBON FUEL

Natural gas, the lowest carbon fuel, is a technically feasible option for CO_2 control of the pelletizers.

5.30.2.4 INSTALLATION OF ENERGY EFFICIENCY OPTIONS ON THE PELLETIZERS

Each of the aforementioned energy efficiency options in Step 1 is technically feasible for CO_2 control of the pelletizers, with the exception of replacement burners as this is a new installation.

5.30.3 RANK OF REMAINING CONTROL TECHNOLOGIES (STEP 3)

Pelletizer technology selection, lower carbon fuel selection, and installation of energy efficient options are the remaining technically feasible control options for minimizing CO_2 emissions from the pelletizer. It is unclear which option has a more significant impact on emissions of CO_2 from the facility.

5.30.4 EVALUATION OF MOST STRINGENT CONTROLS (STEP 4)

5.30.4.1 SELECTION OF THE MOST EFFICIENT PELLETIZER TECHNOLOGY

As discussed previously, it is in PyraMax's interest to install and operate the most efficient pelletizer that can meet the design specifications for the project.

5.30.4.2 SELECTION OF THE LOWEST CARBON FUEL

Natural gas is the lowest emitting carbon fuel that could be relied upon for the proposed operation. Propane will be used as a backup fuel.

5.30.4.3 INSTALLATION OF ENERGY EFFICIENCY OPTIONS ON THE PELLETIZERS

No adverse energy, environmental, or economic impacts are associated with the energy efficient operating practices for reducing CO_2 emissions from the pelletizers. The environmental benefits include fuel savings and reduction of GHG emissions, as well as other criteria pollutant emissions, due to the efficiency gains.

5.30.5 SELECTION OF CO_2 BACT (STEP 5)

A proposed pelletizer design will be the best technology fit with PyraMax's proposed project since it produces the required quality. Additionally, selection of natural gas as a primary fuel (with propane as a backup fuel) results in the lowest CO_2 emissions from combustion.

Based on the top-down process described above for control of GHG from the pelletizers, PyraMax is proposing that the firing of natural gas as the primary fuel source and the operation of several energy efficiency options constitutes BACT for the pelletizers. These energy efficiency options are summarized in Table 5-23.

TABLE 5-23. SUMMARY OF ENERGY EFFICIENCY OPTIONS FOR PELLETIZERS

Energy Efficiency Option	Features of Pelletizers
Pelletizer maintenance	The pelletizers and auxiliary equipment will be maintained per the pelletizers manufacturer's recommendations.
Pelletizers process control	The pelletizers will have instrumentation and control devices for monitoring combustion.
Reduction of excess air	Combustion air and flue gas will be adjusted as necessary to optimize combustion efficiency and minimize excess air.
Improved pelletizer insulation	The pelletizers will be insulated to manufacturer's specifications to minimize heat loss.

PyraMax proposes a CO_2e BACT emission limit of 44,446 tons per year (tpy) CO_2e on a 12-month rolling average basis from each pelletizer. PyraMax derived the proposed BACT emission limit on the basis of CO_2, CH_4, and N_2O emission calculations from combustion the proposed fuels.

Compliance with the proposed BACT limit will be demonstrated based on the annual CO_2 emissions calculated using the fuel throughput for each pelletizer. CH_4 and N_2O emissions will also be calculated and included towards the CO_2e limitation and are described in more detail in Sections 5.31 and 5.32.

5.31 PELLETIZERS - CH_4 BACT

5.31.1 IDENTIFICATION OF POTENTIAL CONTROL TECHNIQUES (STEP 1)

Available control options for minimizing CH_4 emissions from the pelletizer include selection of a high efficiency pelletizer and operating practices that promote energy efficiency to reduce fuel usage.

5.31.2 ELIMINATION OF TECHNICALLY INFEASIBLE CONTROL OPTIONS (STEP 2)

Pelletizer selection and energy efficient operating practices are the only technically feasible control options for reducing CH_4 emissions from the pelletizer.

5.31.3 RANK OF REMAINING CONTROL TECHNOLOGIES (STEP 3)

High efficiency pelletizer selection and energy efficient operating practices are evaluated in the remaining steps of the CH_4 BACT analysis for the pelletizer. It is unclear which option has a more significant impact on emissions of CH_4 from the facility; therefore, no ranking of control options is performed.

5.31.4 EVALUATION OF MOST STRINGENT CONTROLS (STEP 4)

The most efficient, technically feasible control options involve selection of a high efficiency pelletizer and use of energy efficient practices.

5.31.5 SELECTION OF CH_4 BACT (STEP 5)

PyraMax will select the most efficient pelletizer that meets the design criteria and is implementing the energy efficiency efforts as described in Section 5.30.5. Through these efforts to maximize the unit's efficiency, CH_4 emissions from the pelletizers are inherently reduced and kept to a minimum.

As described in Section 5.30.5, PyraMax proposes a CO_2e BACT emission limit of 44,446 tons per year (tpy) CO_2e on a 12-month rolling average basis from each pelletizer. The CH_4 portion of the proposed CO_2e BACT limit will be calculated based on the emission factor per fuel type in Table C-2 to 40 CFR 98 Subpart C and the GWP of 21 (the current GWP per the version of 40 CFR 98 Subpart A).

5.32 PELLETIZERS - N_2O BACT

5.32.1 IDENTIFICATION OF POTENTIAL CONTROL TECHNIQUES (STEP 1)

N_2O catalysts have been used in nitric/adipic acid plant applications to minimize N_2O emissions.[100] Tailgas from the nitric acid production process is routed to a reactor vessel with a N_2O catalyst followed by ammonia injection and a NO_X catalyst.

High efficiency pelletizer technology selection and energy efficient operating practices are additionally available control technology options for N_2O reduction.

5.32.2 ELIMINATION OF TECHNICALLY INFEASIBLE CONTROL OPTIONS (STEP 2)

N_2O catalysts have not been used to control N_2O emissions in pelletizer applications as yet. In addition, the very low N_2O concentrations present in the pelletizer exhaust stream would make installation of N_2O catalysts technically infeasible. In comparison, the application of a catalyst in the nitric acid industry sector has been effective due to the high (1,000-2,000 ppm) N_2O concentration in those exhaust streams. N_2O catalysts are eliminated as a technically feasible option for the proposed project.

With N_2O catalysts eliminated, efficient pelletizer technology selection and energy efficient operating practices are the only available and technically feasible control options for N_2O reduction from the pelletizer.

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[100] http://www.catalysts.basf.com/Main/mediaroom/10years_worldscale_experience_in_reducing_nitrous_.be

5.32.3 RANK OF REMAINING CONTROL TECHNOLOGIES (STEP 3)

High efficiency pelletizer selection and energy efficient operating practices are evaluated in the remaining steps of the N_2O BACT analysis for the pelletizer. It is unclear which option has a more significant impact on emissions of N_2O from the facility; therefore, no ranking of control options is performed.

5.32.4 EVALUATION OF MOST STRINGENT CONTROLS (STEP 4)

No adverse energy, environmental, or economic impacts are associated with pelletizer selection and energy efficient operating practices for reducing N_2O emissions from the pelletizers.

5.32.5 SELECTION OF N_2O BACT (STEP 5)

PyraMax will select an efficient pelletizer that meets the design requirements for the proposed facility and is implementing the energy efficiency efforts as described in Section 5.30.5. Through these efforts to maximize the unit's efficiency, N_2O emissions from the pelletizer are inherently reduced and kept to a minimum.

As described in Section 5.30.5, PyraMax proposes a CO_2e BACT emission limit of 44,446 tons per year (tpy) CO_2e on a 12-month rolling average basis from each pelletizer. The N_2O portion of the proposed CO_2e BACT limit will be calculated based on the emission factor per fuel type in Table C-2 to 40 CFR 98 Subpart C and the GWP of 310.0 (the current GWP per the version of 40 CFR 98 Subpart A).

5.33 NATURAL GAS BOILERS – CO_2 BACT

It is important to note that the proposed units would be exempt from permitting per [INSERT GA REFERENCE]. Therefore, PyraMax has presented an abbreviated GHG BACT discussion for these units.

5.33.1 IDENTIFICATION OF POTENTIAL CO_2 CONTROL TECHNIQUES (STEP 1)

The following potential CO_2 control strategies for the natural gas boilers were considered as part of this BACT analysis:

- Carbon capture and storage (discussed in Section 5.27.1.1 above)
- Selection of the most efficient boiler technology
- Selection of the lowest carbon fuel
- Installation of energy efficient options for the boilers

5.33.1.1 SELECTION OF THE MOST EFFICIENT BOILER TECHNOLOGY

Natural gas boiler design is limited for units of this size (the proposed natural gas boilers will be less than 10 MMbtu/hr units). Therefore, differences in boiler efficiency are expected to be minimal. However, it is in PyraMax's best interest from a fuel efficiency standpoint to purchase an efficient boiler.

5.33.1.2 SELECTION OF THE LOWEST CARBON FUEL

For GHG BACT analyses, low-carbon intensity fuel selection is the primary control option that can be considered a lower emitting process. The natural gas boilers will combust natural gas as a primary fuel with propane gas as the fuel fired during periods of interrupted natural gas supply. Natural gas is the lowest emitting GHG fuel on a direct carbon basis than all other fuels.

5.33.1.3 INSTALLATION OF ENERGY EFFICIENCY OPTIONS ON THE NATURAL GAS BOILERS

In November 2010, the U.S. EPA provided a white paper that addresses control technologies, energy efficiency measures, and fuel switching options for industrial, commercial and institutional boilers. The energy efficiency options listed in the GHG BACT Guidance for the Boilers are:

- Burner replacement (for existing units)
- Maintenance
- Process control and combustion optimization
- Insulation

Additionally, the General GHG Permitting Guidance references several energy efficiency benchmarking tools. However, these tools are not specific and relevant to the small gas-fired boilers in the clay processing industry.

5.33.2 ELIMINATION OF TECHNICALLY INFEASIBLE CONTROL OPTIONS (STEP 2)

5.33.2.1 CARBON CAPTURE AND STORAGE

The levels of CO_2 emissions (both concentration in the flue gas and amount) from the natural gas boilers are approximately the same as the rotary kilns. While potentially available for certain high purity CO_2 streams, CCS is technically infeasible for the natural gas boilers for the reasons discussed in Section 5.27.2.1 for the rotary kilns.

5.33.2.2 SELECTION OF THE MOST EFFICIENT BOILER TECHNOLOGY

Due to the limited variability of natural gas boiler efficiencies on units this small, PyraMax cannot currently definitely differentiate between separate technologies. However, PyraMax will choose an efficient boiler.

5.33.2.3 SELECTION OF THE LOWEST CARBON FUEL

Natural gas, the lowest carbon fuel, is a technically feasible option for CO_2 control of the natural gas boilers.

5.33.2.4 INSTALLATION OF ENERGY EFFICIENCY OPTIONS ON THE BOILERS

Each of the aforementioned energy efficiency options in Step 1 is technically feasible for CO_2 control of the natural gas boilers, with the exception of replacement burners as this is a new installation.

5.33.3 RANK OF REMAINING CONTROL TECHNOLOGIES (STEP 3)

Boiler technology selection, lower carbon fuel selection, and installation of energy efficient options are the remaining technically feasible control options for minimizing CO_2 emissions from the natural gas boilers. It is unclear which option has a more significant impact on emissions of CO_2 from the facility.

5.33.4 EVALUATION OF MOST STRINGENT CONTROLS (STEP 4)

5.33.4.1 SELECTION OF THE MOST EFFICIENT BOILER TECHNOLOGY

As discussed previously, it is in PyraMax's interest to install and operate an efficient natural gas boiler.

5.33.4.2 SELECTION OF THE LOWEST CARBON FUEL

Natural gas is the lowest emitting carbon fuel that could be relied upon for the proposed operation. Propane will be used as a backup fuel.

5.33.4.3 INSTALLATION OF ENERGY EFFICIENCY OPTIONS ON THE NATURAL GAS BOILERS

No adverse energy, environmental, or economic impacts are associated with the energy efficient operating practices for reducing CO_2 emissions from the natural gas boilers. The environmental benefits include fuel savings and reduction of GHG emissions, as well as other criteria pollutant emissions, due to the efficiency gains.

5.33.5 SELECTION OF CO_2 BACT (STEP 5)

The proposed natural gas boilers design will be an efficient unit that reduces fuel consumption. Additionally, selection of natural gas as a primary fuel (with propane as a backup fuel) results in the lowest CO_2 emissions from combustion.

Based on the top-down process described above for control of GHG from the natural gas boilers, PyraMax is proposing that the firing of natural gas as the primary fuel source and the operation of several energy efficiency options constitutes BACT for the natural gas boilers. These energy efficiency options are summarized in Table 5-24.

TABLE 5-24. SUMMARY OF ENERGY EFFICIENCY OPTIONS FOR NATURAL GAS BOILERS

Energy Efficiency Option	Features of Boilers
Boiler maintenance	The boilers and auxiliary equipment will be maintained per the boiler manufacturer's recommendations.
Boiler process control	The boilers will have instrumentation and control devices for monitoring combustion.
Reduction of excess air	Combustion air and flue gas will be adjusted as necessary to optimize combustion efficiency and minimize excess air.
Improved boiler insulation	The boilers will be insulated to manufacturer's specifications to minimize heat loss.

PyraMax proposes a CO_2e BACT emission limit of 5,809 tons per year (tpy) CO_2e on a 12-month rolling average basis from each natural gas boiler. PyraMax derived the proposed BACT emission limit on the basis of CO_2, CH_4, and N_2O emission calculations from combustion the proposed fuels.

Compliance with the proposed BACT limit will be demonstrated based on the annual CO_2 emissions calculated using the fuel throughput for each natural gas boiler. CH_4 and N_2O emissions will also be calculated and included towards the CO_2e limitation and are described in more detail in Sections 5.34 and 5.35.

Additionally, these units are subject to 40 CFR 63 Subpart DDDDD (the Boiler MACT) and have biennial tune-up requirements.

5.34 NATURAL GAS BOILERS - CH_4 BACT

5.34.1 IDENTIFICATION OF POTENTIAL CONTROL TECHNIQUES (STEP 1)

Available control options for minimizing CH_4 emissions from the natural gas boilers include selection of a high efficiency boiler and operating practices that promote energy efficiency to reduce fuel usage.

5.34.2 ELIMINATION OF TECHNICALLY INFEASIBLE CONTROL OPTIONS (STEP 2)

Boiler selection and energy efficient operating practices are the only technically feasible control options for reducing CH_4 emissions from the natural gas boilers.

5.34.3 RANK OF REMAINING CONTROL TECHNOLOGIES (STEP 3)

High efficiency boiler selection and energy efficient operating practices are evaluated in the remaining steps of the CH_4 BACT analysis for the natural gas boilers. It is unclear which option has a more significant impact on emissions of CH_4 from the facility; therefore, no ranking of control options is performed.

5.34.4 EVALUATION OF MOST STRINGENT CONTROLS (STEP 4)

The most efficient, technically feasible control options involve selection of a high efficiency natural gas boiler and use of energy efficient practices.

5.34.5 SELECTION OF CH_4 BACT (STEP 5)

PyraMax will select the most efficient natural gas boilers that meet the design criteria and is implementing the energy efficiency efforts as described in Section 5.33.1.3. Through these efforts to maximize the unit's efficiency, CH_4 emissions from the natural gas boilers are inherently reduced and kept to a minimum.

As described in Section 5.33.5, PyraMax proposes a CO_2e BACT emission limit of 5,809 tons per year (tpy) CO_2e on a 12-month rolling average basis from each natural gas boiler. The CH_4 portion of the proposed CO_2e BACT limit will be calculated based on the emission factor per fuel type in Table C-2 to 40 CFR 98 Subpart C and the GWP of 21 (the current GWP per the version of 40 CFR 98 Subpart A).

5.35 NATURAL GAS BOILERS - N_2O BACT

5.35.1 IDENTIFICATION OF POTENTIAL CONTROL TECHNIQUES (STEP 1)

N_2O catalysts have been used in nitric/adipic acid plant applications to minimize N_2O emissions.[101] Tailgas from the nitric acid production process is routed to a reactor vessel with a N_2O catalyst followed by ammonia injection and a NO_X catalyst.

High efficiency boiler technology selection and energy efficient operating practices are additionally available control technology options for N_2O reduction.

5.35.2 ELIMINATION OF TECHNICALLY INFEASIBLE CONTROL OPTIONS (STEP 2)

N_2O catalysts have not been used to control N_2O emissions in small (< 10 MMbtu/hr) natural gas boiler applications as yet. In addition, the very low N_2O concentrations present in the boiler exhaust stream would make installation of N_2O catalysts technically infeasible. In comparison, the application of a catalyst in the nitric acid industry sector has been effective due to the high (1,000-2,000 ppm) N_2O concentration in those exhaust streams. N_2O catalysts are eliminated as a technically feasible option for the proposed project.

With N_2O catalysts eliminated, efficient boiler technology selection and energy efficient operating practices are the only available and technically feasible control options for N_2O reduction from the natural gas boilers.

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[101] http://www.catalysts.basf.com/Main/mediaroom/10years_worldscale_experience_in_reducing_nitrous_.be

5.35.3 RANK OF REMAINING CONTROL TECHNOLOGIES (STEP 3)

High efficiency boiler selection and energy efficient operating practices are evaluated in the remaining steps of the N_2O BACT analysis for the natural gas boilers. It is unclear which option has a more significant impact on emissions of N_2O from the facility; therefore, no ranking of control options is performed.

5.35.4 EVALUATION OF MOST STRINGENT CONTROLS (STEP 4)

No adverse energy, environmental, or economic impacts are associated with boiler selection and energy efficient operating practices for reducing N_2O emissions from the natural gas boilers.

5.35.5 SELECTION OF N_2O BACT (STEP 5)

PyraMax will select an efficient natural gas boiler that meets the design requirements for the proposed facility and is implementing the energy efficiency efforts as described in Section 5.33.1.3. Through these efforts to maximize the unit's efficiency, N_2O emissions from the natural gas boilers are inherently reduced and kept to a minimum.

As described in Section 5.33.5, PyraMax proposes a CO_2e BACT emission limit of 5,809 tons per year (tpy) CO_2e on a 12-month rolling average basis from each natural gas boiler. The N_2O portion of the proposed CO_2e BACT limit will be calculated based on the emission factor per fuel type in Table C-2 to 40 CFR 98 Subpart C and the GWP of 310.0 (the current GWP per the version of 40 CFR 98 Subpart A).

5.36 EMERGENCY ENGINES – GHG BACT

The two (2) 1,000-kW emergency generator will be powered by two (2) separate 500 kW diesel-fueled engines. The engines will be used for emergency purposes only except for weekly readiness testing. The following sections propose appropriate GHG BACT emission limitations for CO_2, CH_4, and N_2O emissions from the emergency generator engines.

5.36.1 CO_2 BACT EVALUATION

CO_2 emissions from the generator engines are produced from the combustion of hydrocarbons present in the diesel fuel.

5.36.1.1 STEP 1 – IDENTIFY ALL CONTROL TECHNOLOGIES

CCS is not considered an available control option for emergency equipment that operates on an intermittent basis and must be immediately available during plant emergencies without the constraint of starting up the CCS process. With no add-on controls available, the only effective methods of reducing CO_2 emissions from emergency generator engines are selecting the generator set that has a high fuel efficiency and fuel selection.

5.36.1.2 STEP 2 – TECHNICAL FEASIBILITY ANALYSIS

Selecting the generator set with a high fuel efficiency is a technically feasible CO_2 control option. The only technically feasible fuel for an emergency generator engine is diesel fuel. While natural gas-fueled generator engines may provide lower CO_2 emissions per unit of power output, natural gas is not considered a technically feasible fuel for the emergency generator engines since they will be used in the event of facility-wide power outage when natural gas supplies may be interrupted. An onboard diesel fuel tank is the only uninterruptible fuel supply available for this type of emergency engine.

5.36.1.3 STEP 3 – RANKING OF REMAINING CONTROL TECHNOLOGIES BY EFFECTIVENESS

PyraMax is currently evaluating emergency engines. However, PyraMax will evaluate the brake specific fuel consumption (BSFC) for all models available from leading engine manufacturers. BSFC is a commonly used measure of fuel efficiency for engines.

5.36.1.4 STEP 4 – TOP-DOWN EVALUATION OF CONTROL OPTIONS

No adverse energy, environmental, or economic impacts are associated with fuel efficient engine selection for reducing CO_2 emissions from the emergency generator engines.

5.36.1.5 STEP 5 – SELECT CO_2 BACT FOR EMERGENCY GENERATOR ENGINES

Based on the selection of a fuel efficient generator, PyraMax proposes a CO_2e BACT limit of 153 tpy on a 12-month rolling average basis for the two (2) generator engine sets combined (excluding emergency use). To comply with the proposed CO_2e BACT limit, PyraMax will purchase emergency generator internal combustion engines (ICEs) certified by the manufacturer to meet or exceed a BSFC of 7,000 Btu/hp-hr and will also monitor diesel fuel usage.

Actual CO_2 emissions from the generator engines will be calculated based on the fuel usage records and the emission factor for distillate fuel oil No. 2 combustion from Table C-1 to Subpart C of the MRR. CH_4 and N_2O emissions will also be calculated and included towards the CO_2e limitation and are described in more detail in Sections 5.36.2 and 5.36.3. Operation of each generator ICE, for the purposes of maintenance checks and readiness testing (per recommendations from the government, manufacturer/vendor, or insurance), will be limited to 100 hours per year.

5.36.2 CH_4 BACT EVALUATION

CH_4 emissions from diesel-fueled engines form as a result of incomplete combustion of hydrocarbons present in the diesel fuel.

5.36.2.1 STEP 1 – IDENTIFY ALL CONTROL TECHNOLOGIES

With no add-on CH_4 control options available, fuel efficient engine selection and combustion design controls are the only effective methods of reducing CH_4 emissions from the generator engines. Available combustion design controls for ICEs include electronic fuel/air ratio control, timing control, pre-chamber ignition, and turbochargers. Proper combustion design controls can ensure efficient engine performance and will result in lower CH_4 emissions.

5.36.2.2 STEP 2 – TECHNICAL FEASIBILITY ANALYSIS

Fuel efficient engine selection and combustion design controls are technically feasible options for reducing CH_4 emissions from emergency generator engines.

5.36.2.3 STEP 3 – RANKING OF REMAINING CONTROL TECHNOLOGIES BY EFFECTIVENESS

Since fuel efficient engine selection and combustion design controls will both be implemented for CH_4 emissions control, no ranking of control options is necessary.

5.36.2.4 STEP 4 – TOP-DOWN EVALUATION OF CONTROL OPTIONS

No adverse energy, environmental, or economic impacts are associated with fuel efficient engine selection and combustion design controls for reducing CH_4 emissions from the generator engines.

5.36.2.5 STEP 5 – SELECT CH_4 BACT FOR EMERGENCY GENERATOR ENGINES

As described in Section 5.36.1.5, based on the selection of a fuel efficient generator, PyraMax proposes a CO_2e BACT limit of 153 tpy on a 12-month rolling average basis for the two (2) generator engine sets combined (excluding emergency use). To comply with the proposed CO_2e BACT limit, PyraMax will purchase emergency generator internal combustion engines (ICEs) certified by the manufacturer to meet or exceed a BSFC of 7,000 Btu/hp-hr and will also monitor diesel fuel usage.

The CH_4 portion of the proposed CO_2e BACT limit will be calculated based on the emission factor per fuel type in Table C-2 to 40 CFR 98 Subpart C and the GWP of 21 (the current GWP per the version of 40 CFR 98 Subpart A).

5.36.3 N_2O BACT EVALUATION

N_2O emissions from diesel-fueled engines form solely as a byproduct of combustion.

5.36.3.1 STEP 1 – IDENTIFY ALL CONTROL TECHNOLOGIES

PyraMax is not aware of any available add-on controls designed specifically to reduce N_2O emissions from diesel engines. In addition, a literature search revealed no engine combustion design controls or other operating practices that were known to reduce N_2O formation. Therefore, fuel efficient engine selection is the only available control option for reducing N_2O emissions from the generator engines.

5.36.3.2 STEP 2 – TECHNICAL FEASIBILITY ANALYSIS

Fuel efficient engine selection is a technically feasible option for reducing N_2O emissions from emergency generator engines.

5.36.3.3 STEP 3 – RANKING OF REMAINING CONTROL TECHNOLOGIES BY EFFECTIVENESS

Since fuel efficient engine selection is the only available control option, no control option ranking is necessary.

5.36.3.4 STEP 4 – TOP-DOWN EVALUATION OF CONTROL OPTIONS

No adverse energy, environmental, or economic impacts are associated with fuel efficient engine selection for reducing N_2O emissions from the generator engines.

5.36.3.5 STEP 5 – SELECT N_2O BACT FOR EMERGENCY GENERATOR ENGINES

As described in Section 5.36.1.5, based on the selection of a fuel efficient generator, PyraMax proposes a CO_2e BACT limit of 153 tpy on a 12-month rolling average basis for the two (2) generator engine sets combined (excluding emergency use). To comply with the proposed CO_2e BACT limit, PyraMax will purchase emergency generator internal combustion engines (ICEs) certified by the manufacturer to meet or exceed a BSFC of 7,000 Btu/hp-hr and will also monitor diesel fuel usage.

The N_2O portion of the proposed CO_2e BACT limit will be calculated based on the emission factor per fuel type in Table C-2 to 40 CFR 98 Subpart C and the GWP of 310 (the current GWP per the version of 40 CFR 98 Subpart A).

6. CASE-BY-CASE MACT ANALYSIS

The facility will be a major source of HAPs, having emissions of more than 10 tons per year of a single HAP, and 25 tons per year of a combination of HAPs. The primary HAPs emitted by facility processes include emissions of the acid gases HF and HCl from the facility kilns, and emissions of methanol from the facility pelletizers. Small combustion related emissions of other HAPs, such as n-hexane, occur from natural gas combustion at the facility (or propane when it is used as a backup fuel).

Because the emissions of facility-wide HAPs exceed the major source thresholds of 10 tons per year of a single HAP, and 25 tons per year of a combination of HAPs, and there is no NESHAP promulgated for ceramic pellet manufacturing facilities such as the PyraMax facility, then HAP emissions from the facility are subject to a Case-by-Case MACT determination under 112(g) of the Clean Air Act Amendments of 1990. The Section 112(g)(2)(B) trigger date for Georgia is June 29, 1998. The requirements for a Case-by-Case MACT analysis are outlined in 40 CFR Part 63, Subpart B, Requirements for Control Technology Determinations for Major Sources in Accordance with Clean Air Act Sections 112(g) and 112(j).

The facility emission sources subject to a Case-by-Case MACT evaluation would be the facility kilns, pelletizers, and natural gas boilers. Other sources of HAPs at the facility are minor in nature and primarily related to combustion of natural gas. This section discusses the regulatory basis for MACT, approach used in completing the MACT analyses, and the MACT analyses for the proposed equipment. Supporting documentation is included in Appendix E.

6.1 MACT DEFINITION

The definition of MACT is provided in 40 CFR 63.41:

Maximum achievable control technology (MACT) emission limitation for new sources means the emission limitation which is not less stringent that the emission limitation achieved in practice by the best controlled similar source, and which reflects the maximum degree of deduction in emissions that the permitting authority, taking into consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements, determines is achievable by the constructed or reconstructed major source.

The general principles in conducting a Case-by-Case MACT determination is defined in 40 CFR 63.43(d):

(1) The MACT emission limitation or MACT requirements recommended by the applicant and approved by the permitting authority shall not be less stringent than the emission control which is achieved in practice by the best controlled similar source, as determined by the permitting authority.

(2) Based upon available information, as defined in this subpart, the MACT emission limitation and control technology (including any requirements under paragraph (d)(3) of this section) recommended

by the applicant and approved by the permitting authority shall achieve the maximum degree of reduction in emissions of HAP which can be achieved by utilizing those control technologies that can be identified from the available information, taking into consideration the costs of achieving such emission reduction and any non-air quality health and environmental impacts and energy requirements associated with the emission reduction.

(3) The applicant may recommend a specific design, equipment, work practice, or operational standard, or a combination thereof, and the permitting authority may approve such a standard if the permitting authority specifically determines that it is not feasible to prescribe or enforce an emission limitation under the criteria set forth in section 112(h)(2) of the Act.

(4) If the Administrator has either proposed a relevant emission standard pursuant to section 112(d) or section 112(h) of the Act or adopted a presumptive MACT determination for the source category which includes the constructed or reconstructed major source, then the MACT requirements applied to the constructed or reconstructed major source shall have considered those MACT emission limitations and requirements of the proposed standard or presumptive MACT determination.

As mentioned above, there is no relevant NESHAP standard currently promulgated for the ceramic pellet manufacturing industry. Therefore, there are no direct comparisons that can be made pursuant to 40 CFR 63.43(d)(4). However, there are promulgated NESHAPs for similar facility operations as conducted at the facility (i.e. Subpart KKKKK – Clay Ceramics Manufacturing). Development and background of any such similar source categories to ceramic proppant manufacturing will be discussed in the analysis as appropriate.

6.2 GUIDELINES FOR CASE-BY-CASE MACT DETERMINATIONS

Limited guidance is available regarding preparation of a 112(g) Case-by-Case MACT analysis. The application requirements for a Case-by-Case MACT determinations are specified in 40 CFR 63.43(e)(1).

An application for a MACT determination (whether a permit application under title V of the Act, an application for a Notice of MACT Approval, or other document specified by the permitting authority under paragraph (c)(2)(ii) of this section) shall specify a control technology selected by the owner or operator that, if properly operated and maintained, will meet the MACT emission limitation or standard as determined according to the principles set forth in paragraph (d) of this section.

Further information to provide in the analysis is specified in 40 CFR 63.43(e)(2) for constructed or reconstructed major sources that would require additional control technology or a change in control technology. These requirements are summarized in Table 6-1.

TABLE 6-1. CASE-BY-CASE MACT REQUIREMENTS PER 40 CFR 63.43(E)(2)

Regulatory Citation – 40 CFR 63.43(e)(2)	Requirement
(i)	The name and address (physical location) of the major source to be constructed or reconstructed
(ii)	A brief description of the major source to be constructed or reconstructed and identification of any listed source category or categories in which it is included
(iii)	The expected commencement date for the construction or reconstruction of the major source
(iv)	The expected completion date for construction or reconstruction of the major source
(v)	The anticipated date of start-up for the constructed or reconstructed major source
(vi)	The HAP emitted by the constructed or reconstructed major source, and the estimated emission rate for each such HAP, to the extent this information is needed by the permitting authority to determine MACT
(vii)	Any federally enforceable emission limitations applicable to the constructed or reconstructed major source
(viii)	The maximum and expected utilization of capacity of the constructed or reconstructed major source, and the associated uncontrolled emission rates for that source, to the extent this information is needed by the permitting authority to determine MACT
(ix)	The controlled emissions for the constructed or reconstructed major source in tons/yr at expected and maximum utilization of capacity, to the extent this information is needed by the permitting authority to determine MACT
(x)	A recommended emission limitation for the constructed or reconstructed major source consistent with the principles set forth in paragraph (d) of this section
(xi)	The selected control technology to meet the recommended MACT emission limitation, including technical information on the design, operation, size, estimated control efficiency of the control technology (and the manufacturer's name, address, telephone number, and relevant specifications and drawings, if requested by the permitting authority)
(xii)	Supporting documentation including identification of alternative control technologies considered by the applicant to meet the emission limitation, and analysis of cost and non-air quality health environmental impacts or energy requirements for the selected control technology
(xiii)	Any other relevant information required pursuant to subpart A

Additional guidelines for conducting a Case-by-Case MACT analysis can also be found in the EPA document *Guidelines for MACT Determinations Under Section 112(j) Requirements (February 2002)*.[102] This document specifies a tiered approach for conducting a MACT analysis.[103] The approach is as follows;

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[102] http://www.epa.gov/ttn/atw/112j/guidance.pdf

[103] Figure 3, Page 3-4 of *Guidelines for MACT Determinations Under Section 112(j) Requirements (February 2002)*

Tier I

1. Identify the MACT emission unit
2. Make a MACT floor finding

If the floor can be determined, proceed to Tier III. If the floor cannot be determined, proceed to Tier II.

Tier II

1. List all available/reasonable applicable control technologies
2. Eliminate technically infeasible control technologies
3. Determine efficiency of applicable control technologies

Tier III

1. Identify maximum emission reduction control technology
2. Conduct an impacts analysis
3. Establish the MACT emission limitation

Based on consideration of the available guidelines for conducting a Case-by-Case MACT analysis, the analysis contained herein will follow the below described methodology.

1. General site information. This information will be provided to satisfy the requirements of 40 CFR 63.43(e)(2). The remainder of the information specified in 40 CFR 63.43(e)(2) will be provided through the following steps of the analysis.
2. Identify the MACT emission unit, and discuss the HAP emissions expected from that unit.
3. Conduct a floor analysis to determine the best controlled similar source.
4. List all available/reasonable applicable control technologies (if a MACT floor source cannot be defined).
5. Eliminate Technically Infeasible Control Technologies (if a MACT floor source cannot be defined).
6. Determine efficiency of applicable control technologies (if a MACT floor source cannot be defined).
7. Identify maximum emission reduction control technology.
8. Conduct an impacts analysis.
9. Establish the MACT emission limitation.

6.3 GENERAL SITE INFORMATION TO BE PROVIDED IN A CASE-BY-CASE MACT ANALYSIS

40 CFR 63.43 (e)(2)(i)

Name: PyraMax Ceramics, LLC

Physical Location: Wrens, GA

40 CFR 63.43(e)(2)(ii)

The proposed facility, which will consist of two lines, will manufacture proppant beads for the oil and gas industry. Proppants improve the well's flow capacity and increase recovery rates.

A granular material must fulfill several conditions to be suitable for use as a propping agent. The material must have high strength to avoid crushing of the particles when exposed to high pressure during their application. The shape of the individual particles should be as spherical as possible. The particle size distribution should be within defined, relatively narrow limits to ensure sufficient gas and oil permeability of fractures propped with the propping agent. Proppant materials are carefully sorted for size, strength, resistance to heat, and sphericity.

The facility is not subject to any listed source categories as described in 40 CFR Part 63. Individual facility equipment is potentially subject to various NESHAP. The following Table 6-2 provides a general listing of facility equipment and potentially applicable NESHAP standards, if promulgated. The table also provides a listing of potentially applicable New Source Performance Standards (NSPS) for the equipment of interest.

TABLE 6-2. FACILITY EQUIPMENT AND POTENTIALLY APPLICABLE FEDERAL REGULATIONS

Facility Equipment	Potentially Applicable NESHAP Standard (40 CFR Part 63)	Potentially Applicable NSPS Standard (40 CFR Part 60)
Calcining Kiln	None Promulgated	Subpart UUU
Pelletizer	None Promulgated	Subpart UUU
Natural Gas Boilers	Subpart DDDDD – Industrial Boiler MACT[1]	N/A[2]
Material Handling Sources	None Promulgated[3]	Subpart OOO[4]
Emergency Generators	Subpart ZZZZ	Subpart IIII

[1] Subpart DDDDD was finalized and published in the Federal Register on March 21, 2011.[104] Subsequent to this finalization, a notice was published in the Federal Register on May 18, 2011 that the effective date of Subpart DDDDD was delayed until such time as judicial review is no longer pending or until the EPA completes its reconsideration of the rules, whichever is earlier.[105] In an EPA press release filed on June 24, 2011, EPA indicated their intention to propose standards to be reconsidered by the end of October 2011, and issue final standards by the end of April 2012. A limited Case-by-Case MACT assessment has been conducted for the small natural gas boilers to be used at the site.

[2] The natural gas boilers planned for the site are less than 10 MMBtu/hr in size and therefore not subject to NSPS Subpart Dc.

[3] Material handling sources at the site are sources of PM only and not expected to be a source of HAP. Some limited fugitive emissions of HAP may occur from material handling of the granular based polyvinyl alcohol material used in the process as a binding agent.

[4] Not all facility material handling equipment is subject to Subpart OOO. Please refer to the Federal Regulatory Analysis as part of this application for more detailed information.

Therefore, per Table 6-2 the applicable emission units being considered for this Case-by-Case MACT analysis would be the facility kilns, pelletizers, and natural gas boilers.

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[104] *http://www.epa.gov/ttn/atw/boiler/fr21mr11m.pdf*

[105] *http://www.epa.gov/ttn/atw/boiler/fr18my11.pdf*

40 CFR 63.43(e)(2)(iii)

Construction of the facility will occur following receipt of the necessary permits and approvals, which is anticipated to occur in the first quarter of 2012.

40 CFR 63.43(e)(2)(iv), (v)

Construction of the facility is anticipated to take approximately two years with completion in 2014, with startup of the facility occurring in 2014.

40 CFR 63.43(e)(2)(vii)

The final permit issued for the facility will be a construction permit under the PSD program. Terms and conditions of that permit will include derived Case-by-Case MACT limitations for the sources of interest, as well as limitations established under PSD (40 CFR 52.21) and New Source Performance Standards (NSPS) for different facility equipment.

6.4 CASE-BY-CASE MACT ANALYSIS FOR THE FACILITY KILNS

6.4.1 STEP 1 – IDENTIFY THE MACT EMISSION UNIT

The facility kilns are a source of acid gas HAP emissions, specifically emissions of the acid gases HCl and HF. Small emissions of HAPs from natural gas combustion would also be anticipated from the kiln burner.[106] A summary of the HAP emissions from the facility kilns, as well as the facility as a whole, can be found in the calculations provided in Appendix C. Emissions of the acid gases HF and HCl from the kilns, post control, are estimated as approximately 3 tons per year HCl from each kiln, and approximately 4.5 tons per year HF from each kiln, while combustion related HAP emissions are estimated as less than 0.5 tons per year per kiln. No significant emissions of other HAPs from the facility kilns are anticipated.

As emissions of the acid gas HAPs HF and HCl are the only HAPs emitted from the kilns in significant quantities, this Case-by-Case MACT analysis is being conducted to assess the proper control of acid gases from the facility kilns. Emissions of acid gases are controlled in the same manner as through control of Sulfur Dioxide (SO_2), through use of sorbent injection, dry scrubbers, wet scrubbers, etc.

6.4.2 STEP 2 – MACT FLOOR ANALYSIS

Although there is no applicable NESHAP which would apply to the PyraMax kilns, there are similar industries which have an established NESHAP, such as Subpart KKKKK, the

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[106] *HAP emissions as specified in AP-42, Tables 1.4-3 and 1.4-4 for natural gas combustion. Propane would be used as a backup fuel. AP-42, Section 1.5 does not provide any data for individual HAPs from propane combustion. However, emissions of HAPs from propane combustion would not be anticipated to be more significant than that from natural gas combustion.*

Clay Ceramics Manufacturing. EPA found during development of this standard that the MACT floor for new clay ceramics tunnel kilns was use of either dry lime injection fabric filters (sorbent injection), dry lime scrubber fabric filters (dry scrubber), or a wet scrubber for control of acid gases (HF, HCl).[107] Therefore, review of available document for a similar source category indicated that there was the potential for establishing emission controls for acid gases from the facility kilns.

A review of available data was then conducted in an attempt to establish a MACT floor, or best controlled similar source, for acid gas HAPs for the facility kilns. A review of the RBLC database was conducted for kilns located within Process Code 90.017 (Calciners & Dryers and Mineral Processing Facilities), Process Code 90.008 (Clay and Fly Ash Sintering), and Process Code 90.009 (Clay Products including Brick & Ceramics).[108] Table 6-3 below provides the results of the assessment. Although not all kilns were found to have established limits and controls for the acid gases HF and HCl, some were found to have established limits and controls for SO_2. These sources have also been listed since, as discussed above, the emission controls for SO_2 are effectively the same as the necessary emission controls for the control of HAP acid gases.

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[107] *National Emission Standards forHazardous Air Pollutants for Clay Ceramics Manufacturing; Final Rule May 16, 2003 at FR Vol. 68, No. 95, 26713*

[108] RBLC database refers to the EPA RACT/BACT/LAER Clearinghouse, found at http://cfpub.epa.gov/RBLC/. Although this database is not, by design, intended for direct use in Case-by-Case MACT assessments it can be used to conduct a review for possible best controlled similar sources in establishment of the MACT floor.

TABLE 6-3. RBLC DATABASE QUERY AND RESEARCH RESULTS FOR KILNS

Facility	Process Code	Process	Pollutant	Limit	Control Device	Control Device Efficiency (%)
Carbo Ceramics, Inc. (McIntyre)	90.008[1]	Kiln	HCl	0.036 lb/ton kiln feed (6.26 tpy)	None	N/A
			HF	0.21 lb/ton kiln feed (36.3 tpy)	None	N/A
Carbo Ceramics, Inc. (Toomsboro)	---[2]	Kiln	HCl	0.099 lb/ton kiln feed (8.7 tpy)	None	N/A
			HF	0.433 lb/ton kiln feed (37.92 tpy)	None	N/A
Dalitalia LLC	90.008	Kiln	HCl	0.082 lb/ton Tile[3]	Wet Scrubber	90
			HF	0.082 lb/ton Tile	Wet Scrubber	90
Endicott Clay Products	90.009	Plant 3, Kiln 1	Fluorides[4]	5.22 lb/hr (3-hr avg.)	N/A	N/A
Dalitalia LLC (Muskogee)	90.009	Kilns	HCl	0.080 lb/ton	Wet Scrubber	90
			HF	0.080 lb/ton	Wet Scrubber	90
General Shale Products Corporation, LLC	90.017	Kiln, Aggregate	SO_2	1.10 lb/hr 4.9 ton/yr	Wet Scrubber	98
Celite Corporation[5]	90.017	Diatamaceous Earth Calciner	SO_2	---	Wet Scrubber	98

[1] Emission limits based on Carbo Ceramics, Inc. McIntyre facility air permit (3295-319-0027-V-03-2).
[2] Entry not located in the RBLC database for this facility. Emission limits based on Carbo Ceramics, Inc. Toomsboro facility air permit (3295-319-0029-V-02-1).
[3] Emission limits are provided in lb/ton of tile, so limit may not be directly relatable to operations of PyraMax Ceramics, LLC.
[4] Limit specified as Fluorides, but included as reference since unclear what portion could be Fluorides (as HF).
[5] No specific emission limit provided. Control requirement indicated as Lowest Achievable Emission Rate (LAER).

Multiple facilities were found within the RBLC database with emission limits for HF and HCl. Of those sources reviewed, the facilities with operations most comparable to those at PyraMax are those of the Carbo Ceramics, Inc. facilities located in McIntyre and Toomsboro, Georgia. These facilities have not installed emission controls specifically for HF and HCl, but they have established limits for HF and HCl through permitting action. Other units listed above have installed wet scrubber controls for control of HF and HCl emissions. However, these units are not producers of ceramic proppant, and are not directly similar facility operations to PyraMax.

A review of information for the Carbo Ceramics, Inc. McIntyre facility indicated that the facility submitted documentation in May 2010 for installation of a wet scrubber for control of SO_2 emissions on one of the facility calciners/kilns (CLN2).[109] Information provided as part of the submittal indicated that the wet scrubber was being installed to provide operational flexibility and allow for manufacture of a more diverse range of products. This

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[109] Documentation as found during file review conducted at Georgia EPD on May 20, 2011.

documentation indicated a wet scrubber with a control efficiency of 95% for SO_2 emissions was appropriate.

Although this wet scrubber was not installed at the Carbo Ceramics, Inc. McIntyre facility as a control device for MACT, it is effectively controlling emissions of the acid gases HF and HCl, through the same controls used for control of SO_2 emissions. Therefore, installation of wet scrubber control at a similar source has effectively defined the best controlled similar source, and established the MACT floor for this analysis.

6.4.3 STEP 3 – IDENTIFY MAXIMUM EMISSIONS REDUCTION TECHNOLOGY

Control of the acid gases HF and HCl would be accomplished through use of the same control technologies used for control of SO_2, as established in the Clay Ceramics Manufacturing NESHAP (Subpart KKKKK), as well as other publicly available documentation. It would be expected that control of the acid gases HF and HCl would be controlled to the same degree, if not greater, than the control level of SO_2. Wet scrubber SO_2 removal levels can vary anywhere from 80% to greater than 99%, depending on the scrubber design and reagent materials used. [110] Sorbent injection and dry scrubber systems SO_2 removal levels can vary anywhere from 80% to 90%.[111]

As discussed in the facility BACT analysis, a Catalytic Baghouse system is being used as a control system for multi-control of PM, NO_X, SO_2, and consequently acid gases. This device incorporates a system for dry injection of sorbents for the capture of acid gases. With this system SO_2 removal efficiencies have been indicated from 90% to 97%.

Therefore, although the proposed control system is not a wet scrubber, it will reportedly achieve the same level of control as a wet scrubber. Therefore, use of the Catalytic Baghouse system will represent use of the maximum emission reduction technology available and will be consistent with the removal efficiencies expected for the best controlled similar source, the Carbo Ceramics McIntyre Georgia facility wet scrubber installed on calciner/kiln CLN2.

6.4.4 STEP 4 – IMPACTS ANALYSIS

As stated in 112(j) guidance determination documentation;

Section 112(d) of the Act specifies that if control technology alternatives are being considered to establish an emission standard that would result in emission limitations more stringent than the emission "floors," they must be evaluated by considering costs, non-air quality health and environmental impacts, and energy requirements associated with the expected emission reductions. [112]

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[110] http://www.epa.gov/ttn/catc/dir1/fsprytwr.pdf (EPA -452/F-03-016)

[111] http://www.epa.gov/ttn/catc/dir1/ffdg.pdf (EPA -452/F-03-034)

[112] *Guidelines for MACT Determinations under Section 112(j) Requirements* (February 2002), Page 6-1

Therefore, as the MACT floor has been established and accepted by PyraMax an impacts analysis is not necessary. No beyond the floor technologies are anticipated that would be used to effectively provide sufficient secondary reduction of the acid gases HF and HCl. The MACT floor level established and the selected control technology will provide the maximum degree of reduction for acid gas emissions. Therefore, no “beyond-the-floor” technologies are anticipated that would require an assessment of energy, economic, or environmental impacts.

6.4.5 STEP 5 – MACT EMISSIONS LIMITATION

MACT is established for control of acid gases for the facility kilns by use of the Catalytic Baghouse system. The proposed emission limits for the acid gases HF and HCl are 0.044 lb/ton (4.52 tpy) HF per kiln, and 0.029 lb/ton (2.94 tpy) HCl per kiln.[113] The emission reduction necessary to reach this level of emissions, based on estimated concentrations of fluorine and chlorine in the clay materials processed through the kiln, would be approximately 90% control. Although this level of control is less than the level of control reported by the Carbo Ceramics, Inc. McIntyre facility for control of SO_2[114], as there are no reported instances which could be found of a control technology established on a kiln of the type to be used at PyraMax specifically for control of acid gases, this level of control is proposed as sufficient to satisfy MACT.

6.5 CASE-BY-CASE MACT ANALYSIS FOR THE FACILITY PELLETIZERS

6.5.1 STEP 1 – IDENTIFY THE MACT EMISSION UNIT

The facility pelletizers are a source of organic HAP emissions, specifically methanol emissions. The methanol emissions are associated with the addition of an additive to the mixture material which is fed into the pelletizers. The additive material contains less than 1% by weight methanol.[115] The methanol present in the mixture is driven off in the pelletizers due to the heating element and operating temperature of the pelletizers.

Small emissions of HAPs from natural gas combustion would also be anticipated from the pelletizer burners.[116] A summary of the HAP emissions from the facility pelletizers can be found in the calculations provided in Appendix C. Emissions of methanol from the

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[113] *Emission limits derived based on anticipated concentrations of fluorine and chlorine in clay materials processed by the facility as referenced in Appendix C, and a kiln projected material throughput of 46,688 lb/hr.*

[114] *May 13, 2010 application documentation for the McIntyre facility referenced an estimated emissions reduction of 95% for* SO_2 *following use of the scrubber.*

[115] *Information provided by Anna Koperczak, SSOE, to Trinity Consultants 6/20/11.*

[116] *HAP emissions as specified in AP-42, Tables 1.4-3 and 1.4-4 for natural gas combustion. Propane would be used as a backup fuel. AP-42, Section 1.5 does not provide any data for individual HAPs from propane combustion. However, emissions of HAPs from propane combustion would not be anticipated to be more significant than that from natural gas combustion.*

pelletizers are estimated as approximately 5.48 lb/hr, or 24 tpy. No significant emissions of other HAPs from the facility pelletizers are anticipated.

6.5.2 STEP 2 – MACT FLOOR ANALYSIS

A review of the RBLC database was conducted for pelletizers located within Process Code 90.017 (Calciners & Dryers and Mineral Processing Facilities), Process Code 90.008 (Clay and Fly Ash Sintering), and Process Code 90.009 (Clay Products including Brick & Ceramics) did not indicate any sources within the database identified as having emission limits or controls established for the control of methanol.[117] The search was then expanded to evaluate sources with the above listed process codes for control of Volatile Organic Compound (VOC) emissions, of which methanol would be a component.

The results of review of the RBLC database located several sources which had undergone BACT for dryer devices for VOC. Also, a review of permit documentation for the Carbo Ceramics, Inc. Toomsboro facility also provided information regarding that facility's review of methanol emissions from that facility's spray dryers in historic permitting action in Georgia.[118] A summary table of the documentation reviewed is provided in Table 6-4.

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[117] RBLC database refers to the EPA RACT/BACT/LAER Clearinghouse, found at http://cfpub.epa.gov/RBLC/. Although this database is not, by design, intended for direct use in Case-by-Case MACT assessments it can be used to conduct a review for possible best controlled similar sources in establishment of the MACT floor.

[118] Permit No. 3295-319-0029-V-02-1 issued to the Carbo Ceramics, Inc. Toomsboro facility on December 16, 2009.

TABLE 6-4. RBLC DATABASE QUERY AND RESEARCH RESULTS FOR PELLETIZERS

Facility	Process Code	Process	Pollutant	Limit	Control Device	Control Device Efficiency (%)
Carbo Ceramics, Inc. (Toomsboro)	---[1]	Spray Dryer	Methanol	0.12 lbs/ton of kiln feed not to exceed 10.04 tons per 12-rolling months	None	N/A
Dalitalia, LLC (Muskogee)[2]	90.009	Vertical Dryers	VOC	5.1 lb/hr	Good Combustion Practices	N/A
Dalitalia, LLC (Muskogee)	90.009	Spray Dryers	VOC	0.25 lb/ton	Good Combustion Practices	N/A
Dalitalia, LLC (Muskogee)	90.017	Vertical Dryers	VOC	4.26 lb/hr	Good Combustion Practices	N/A
Dalitalia, LLC (Muskogee)	90.017	Spray Dryers	VOC	0.25 lb/ton	Good Combustion Practices	N/A

[1] Entry not located in the RBLC database for this facility. Emission limits based on Carbo Ceramics, Inc. Toomsboro facility air permit (3295-319-0029-V-02-1). Compliance method is mass balance based on kiln feed and methanol containing additive input records and MSDS.

[2] RBLC ID for the Dalitalia, LLC facility is OK-0110. The same facility is listed under both process code 90.009 and 90.017. Those under Process Code 90.017 are associated with Permit No. 2004-198-TV dated 10/21/05. Those under Process Code 90.009 are associated with Permit No. 2004-198-C(M-1) dated 10/14/05.

A review was also conducted of NESHAP for similar source categories, such as Subpart JJJJJ, the National Emissions Standards for Hazardous Air Pollutants for Brick and Structural Clay Products Manufacturing, as well as Subpart KKKKK, the National Emissions Standards for Hazardous Air Pollutants for Clay Ceramics Manufacturing. A review of these regulations did not reveal any direct discussions regarding the monitoring or control of methanol emissions.

A review of documentation for the Carbo Ceramics, Inc. Toomsboro permitting action indicated that a review of potentially applicable control technologies for control of methanol emissions was reviewed by both the applicant and Georgia EPD, and no controls were found to be either technically or economically feasible for the project. A review of the Notice of MACT approval for the Carbo Ceramics, Inc. Toomsboro facility dated August 14, 2009 indicated that review by the EPD, in conversations with the EPA, had indicated that there were no known cases of similar sources using add-on controls for the control of VOC or HAP in the clay and ceramics products manufacturing industries.[119] Therefore, there is no MACT floor technology for control of methanol emissions from the facility pelletizers.

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[119] Georgia EPD referenced a telephone conversation with Mr. Jeff Telander of the U.S. EPA, project lead for 40 CFR Part 63 Subpart JJJJJ and KKKKK, the established NESHAP for the clay products manufacturing industry.

Therefore, monitoring associated with tracking of the facility's estimated HAP emissions was established as MACT for the Carbo Ceramics, Inc. facility spray dryers.[120] The Carbo Ceramics, Inc. Toomsboro facility spray dryer emission limitations would then effectively serve as the MACT floor.

6.5.3 STEP 3 – LIST ALL AVAILABLE/REASONABLE APPLICABLE CONTROL TECHNOLOGIES

Potential control technologies for control of methanol/VOC emissions from the facility pelletizer would include use of Regenerative Thermal Oxidiation (RTO), catalytic oxidation, biofiltration (biotrickling filter), an organic material condensation system, and pollution prevention or use of substitute materials.

An RTO is a post combustion control technique typically used for volatile organic compound (VOC) control by oxidizing the VOC to CO_2. The RTO system uses a bed of ceramic material to absorb and retain heat from the combustion exhaust gas and uses this heat to preheat the incoming flue gas stream.

Catalytic oxidation is a post combustion control technique used for VOC control. The unit would destroy the methanol in the exhaust gas stream via oxidation where methanol would combust and be converted into CO_2 and water vapor.

Biofiltration could be accomplished by use of a simple biofilter, biotrickling filter, or use of a bioscrubber. Biofiltration is the use of microbes to consume pollutants from a contaminated air stream, including organic compounds such as methanol/VOC. In a biotrickling filter as the air passes through the packed bed of the filter tower, the pollutants are absorbed from the air into the liquid phase to achieve maximum contact with the biomass. A bioscrubber is a modified version of a biotrickling filter where the tower packing is flooded with a liquid phase and the discharge effluent from the bioscrubber is collected in a large tank before being recycled back to the bioscrubber.[121]

An organic material condensation system would be a control device that is used to cool an emissions stream having organic vapors within it, such as methanol, and change the vapors into a liquid that can be collected. The recovered materials can be recovered, refined, or otherwise disposed of.[122]

6.5.4 STEP 4 – ELIMINATE TECHNICALLY INFEASIBLE CONTROL TECHNOLOGIES

As discussed in the BACT analysis for the pelletizers, use of both an RTO and catalytic oxidation for the pelletizers would not be technically infeasible. Also, use of biofiltration

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[120] Permit No. 3295-319-0029-V-02-1 issued to the Carbo Ceramics, Inc. Toomsboro facility on December 16, 2009. Georgia EPD Notice of MACT Approval dated August 14, 2009.

[121] *Using Bioreactors to Control Air Pollution, EPA-456/R-03-003 September 2003*

[122] *Refrigerated Condensers for Control of Organic Air Emissions, EPA-456/R-01-004 December 2001*

cannot be immediately discounted as a technically infeasible control technology. Pollution prevention, through minimization of use of HAP materials, could also be employed. Therefore, these control types will be carried through the analysis.

Regarding biofiltration, there are different forms of biofiltration that could be considered. The primary types of biofiltration are basic biofilters, biotrickling filters, and bioscrubbers.[123]

An organic material condensation system may, however, not be a technically feasible control technology. Documentation reviewed from the Carbo Ceramics, Inc. Toomsboro facility Notice of MACT Approval (August 14, 2009) revealed the following information;

In theory, the methanol emissions from Carbo Ceramics' spray dryers can be reduced by chilling the exhaust gas streams from the spray dryers. As the temperature of the exhaust gas streams is lowered, a portion of the methanol in the exhaust gas streams could be condensed and thus removed. Nevertheless, the methanol concentration in each of the exhaust gas streams from Carbo Ceramics' spray dryers is approximately 6.2 ppm by volume, which is substantially below the low bound of the concentration range (1,000 ppm by volume) for VOC condensation control technology to be effective[26]. In addition to the low VOC/methanol concentration, the spray dryers' exhaust gas streams are rich in water vapor. Condensation of large quantity of water would make the operation of the condensation system even less cost-effective and practical. Based on these findings, condensation is deemed technically infeasible and not considered further for this MACT analysis.[124]

The estimated methanol concentrations within the exhaust gas stream of the pelletizer exhaust stacks at the PyraMax facility is approximately 12.2 ppm.[125] Therefore, the same logic as applied previously by Georgia EPD in their analysis of the Carbo Ceramics, Inc. Toomsboro permit to eliminate an organic material condensation system would be applicable to the PyraMax facility, as concentrations of methanol in the exhaust gas stream would also be estimated at well below 1,000 ppm.

Also, a review of the EPA document Refrigerated Condensers for Control of Organic HAP Emissions indicates that organic material condensation systems are typically installed on systems with an air flow of 10,000 acfm or less. As the exhaust gas streams for the facility pelletizers are estimated at over 100,000 acfm, this may also be demonstrative that there could be issues with applicability of such controls on a large scale. Therefore, organic material condensation systems are considered technically infeasible for this analysis and will not be considered further.

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[123] *Using Bioreactors to Control Air Pollution, EPA-456/R-03-003 September 2003*

[124] *Georgia EPD Notice of MACT Approval for the Carbo Ceramics, Inc. facility dated August 14, 2009, Page 11 of 16. This document referenced the EPA document Survey of Control Technologies for Low Concentration Organic Vapor Streams, EPA 456/R-95-003, May 1995.*

[125] *Based on an estimated emission rate of 5.48 lb/hr methanol per pelletizer stack, and an air flow rate of 89,820 dscfm as provided in Appendix C.*

6.5.5 STEP 5 – DETERMINE EFFICIENCY OF APPLICABLE CONTROL TECHNOLOGIES

The efficiency of control of methanol for the remaining control technologies is provided below in Table 6-5.

TABLE 6-5. ESTIMATED CONTROL EFFICIENCY OF REMAINING CONTROL OPTIONS FOR METHANOL EMISSIONS FROM PELLETIZERS

Control Technology	Estimated Control Efficiency	Reference
Regenerative Thermal Oxidation (RTO)	95-99%	EPA-452/F-03-021
Catalytic Oxidation	95%[1]	EPA-452/F-03-018
Biofiltration	60-99%	EPA-456/R-03-003
Pollution Prevention	N/A	N/A

[1] Documentation reviewed indicated that higher destruction efficiencies of 98-99% are achievable, but require larger catalyst volumes and/or higher temperatures, and are usually designed on a site-specific basis.

6.5.6 STEP 6 – IDENTIFY MAXIMUM EMISSION REDUCTION CONTROL TECHNOLOGY

As indicated above, a wide range of potential control efficiencies was found for the remaining control technologies of interest. All remaining control technologies would appear, on paper, to be capable of achieving greater than 90% control of methanol emissions from the facility pelletizers. However, as referenced above, none of the listed control technologies have been found to have been implemented for control of methanol or VOC emissions from similar sources. For these reasons, there is no directly identified maximum reduction control technology for control of methanol emissions from the facility pelletizers.

The additive used by the facility in the mixture preparation process contains up to 1% by weight of volatiles (which would include methanol). Use of an additive with the minimum amount of methanol and operating the pelletizers at an optimal temperature is the primary method available for minimization of methanol emissions from the facility pelletizers. Any additive material obtained would be anticipated to have some quantity of methanol emitted through the processing and use of the material. Therefore, use of an alternate material with a lower methanol content does not appear feasible.

Each of the remaining control technologies and techniques of interest will be discussed in the following impacts analysis.

6.5.7 STEP 7 – IMPACTS ANALYSIS

A general costing evaluation was then conducted of the remaining control technologies. If evaluating and assuming a removal efficiency for all control technologies evaluated of 95%, based on the estimated methanol emissions per pelletizer of 24 tpy, then the annualized control cost for a control technology to control methanol emissions would need to be less than approximately $230,000 per year to achieve a cost effectiveness of less than $10,000 per ton.[126]

A catalytic oxidation unit would have an annualized cost of anywhere from $8 to $50 per scfm, annually.[127] Conservatively using the low end range of $8 per scfm, that produces an estimated annualized cost of approximately $720,000 per year, based on a flow rate for the pelletizer stacks of approximately 90,000 scfm. Using these conservative assumptions would produce a cost effectiveness of over $30,000 per ton for methanol emissions from the pelletizer. Therefore, use of catalytic oxidation for control of methanol emissions would not be economically feasible.

Similarly, an RTO unit would have an annualized cost of anywhere from $8 to $33 per scfm.[128] As with the catalytic oxidation unit, conservatively using the low end range of $8 per scfm, that produces an estimated annualized cost of approximately $720,000 per year, based on a flow rate for the pelletizer stacks of approximately 90,000 scfm. Using these conservative assumptions would produce a cost effectiveness of over $30,000 per ton for methanol emissions from the pelletizer. Therefore, use of an RTO for control of methanol emissions would not be economically feasible.[129]

A review of information regarding biofilters provided a minimal annualized cost of approximately $3-4 per acfm for a biofilter, with costs for biotrickling filters and bioscrubbers approaching $25 per acfm and greater.[130] Using the value of $3 per acfm, the annualized cost of the unit would be over $300,000 per year, leading to a cost effectiveness of greater than $10,000 per ton. This estimate is considered additionally conservative considering a review of the Georgia EPD Case-by-Case MACT Approval (August 14, 2009) for the Carbo Ceramics, Inc. Toomsboro permit indicated a cost effectiveness for biofiltration of approximately $170,000 per ton. Therefore, use of a biofilter for control of methanol emissions from the facility pelletizers would not be economically feasible.

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[126] *Derived based on an emissions reduction of approximately 23 tpy, with 95% control of an uncontrolled methanol emission rate of 24 tpy.*

[127] *EPA-452/F-03-018, http://www.epa.gov/ttn/catc/dir1/fcataly.pdf. Use of these values is additionally conservative as they are based on 2002 dollars.*

[128] *EPA-452/F-03-021, http://www.epa.gov/ttn/catc/dir1/fregen.pdf Use of these values is additionally conservative as they are based on 2002 dollars.*

[129] *It should be noted that both an RTO and catalytic oxidation unit were not found cost effective for control of VOC emissions from the facility pelletizers. Actual cost effectiveness would likely be much higher than the conservative values provided. Documentation in the Georgia EPD MACT Approval for the Carbo Ceramics, Inc. Toomsboro facility (August 14, 2009) indicated cost effectiveness values in the range of $200,000 per ton for both use of an RTO and catalytic oxidation.*

[130] EPA-456/R-03-003, http://www.epa.gov/ttn/catc/dir1/fbiorect.pdf. Use of these values is additionally conservative as they are based on 2003 dollars, and the fact that use of a biofilter alone, without use of a trickling filter or scrubber system, would potentially not provide the amount of control needed.

6.5.8 STEP 8 – MACT EMISSIONS LIMITATION

The MACT emission limitation for the facility pelletizers is therefore proposed as an emission limit of 0.23 lb/ton of kiln feed, or 24 tpy per pelletizer. Compliance will be demonstrated through a mass balance based on kiln feed, methanol containing additive input records, and MSDS information for the additive materials used.[131]

6.6 CASE-BY-CASE MACT ANALYSIS FOR THE FACILITY NATURAL GAS BOILERS

6.6.1 STEP 1 – IDENTIFY THE MACT EMISSION UNIT

The facility natural gas boilers are small (9.8 MMBtu/hr each), and only small emissions of HAPs from natural gas combustion would also be anticipated.[132] A summary of the HAP emissions from the facility natural gas boilers can be found in the calculations provided in Appendix C. Emissions of total HAPs from the facility natural gas boilers are estimated at less than 0.1 tpy per boiler.

6.6.2 STEP 2 – MACT FLOOR ANALYSIS

40 CFR Part 63, the *National Emissions Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters: Final Rule* was published in the Federal Register on March 21, 2011.[133] This rule would be applicable to the facility natural gas boilers. However, in May 2011 EPA announced a delay of the effective date for the Rule. Then, on June 24, 2011 EPA announced, as part of a filing with the U.S. Court of Appeals for the DC Circuit, that a new Rule will be proposed by the end of October 2011, and the Rule will be finalized by the end of April 2012.[134]

Under the Rule published on March 21, 2011, the only significant requirement under the Rule for the Pyramax facility natural gas boilers would have been conducting a tune-up of the boiler or process heater biennially as specified in 40 CFR 63.7540.[135] The tune-up requirements as specified in 40 CFR 63.7540 are as follows;

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[131] *The difference in this value, and the Carbo Ceramics, Inc. Toomsboro facility spray dryer methanol emission limit is the difference in the size and capacity of the units at the two facilities and the different use of additives compared to the Carbo Ceramics, Inc. Toomsboro facility.*

[132] *HAP emissions as specified in AP-42, Tables 1.4-3 and 1.4-4 for natural gas combustion. Propane would be used as a backup fuel. AP-42, Section 1.5 does not provide any data for individual HAPs from propane combustion. However, emissions of HAPs from propane combustion would not be anticipated to be more significant than that from natural gas combustion. The March 21, 2011 Subpart DDDDD Rule included the use of propane under the definition of natural gas.*

[133] *http://www.epa.gov/ttn/atw/boiler/fr21mr11a.pdf*

[134] *http://www.epa.gov/airquality/combustion/actions.html#jun11*

[135] *Table 3 to Subpart DDDDD published in the Federal Register on March 21, 2011.*

1. As applicable, inspect the burner, and clean or replace any components of the burner as necessary (you may delay the burner inspection until the next scheduled unit shutdown, but you must inspect each burner at least once every 36 months)
2. Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available
3. Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly
4. Optimize total emissions of carbon monoxide. This optimization should be consistent with the manufacturer's specifications, if available
5. Measure the concentrations in the effluent stream of carbon monoxide in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made)
6. Maintain on-site and submit, if requested by the Administrator, an annual report containing the following information;
    a. The concentrations of carbon monoxide in the effluent stream in parts per million by volume, and oxygen in volume percent, measured before and after the adjustments of the boiler.
    b. A description of any corrective actions taken as a part of the combustion adjustment
    c. The type and amount of fuel used over the 12 months prior to the annual adjustment, but only if the unit was physically and legally capable of using more than one type of fuel during that period. Units sharing a fuel meter may estimate the fuel use by each unit.

PyraMax accepts the work done by EPA in development of the MACT floor for the March 21, 2011 Final Rule for sources such as the facility natural gas boilers, and incorporates the standards specified for the natural gas boilers within the Rule as the MACT floor.

6.6.3 STEP 3 – IDENTIFY MAXIMUM EMISSIONS REDUCTION TECHNOLOGY

This step of the analysis is not necessary, as the research and review done by the EPA in development of the March 21, 2011 Rule identified that no emission controls were necessary for sources of the type of the facility small natural gas boilers.

6.6.4 STEP 4 – IMPACTS ANALYSIS

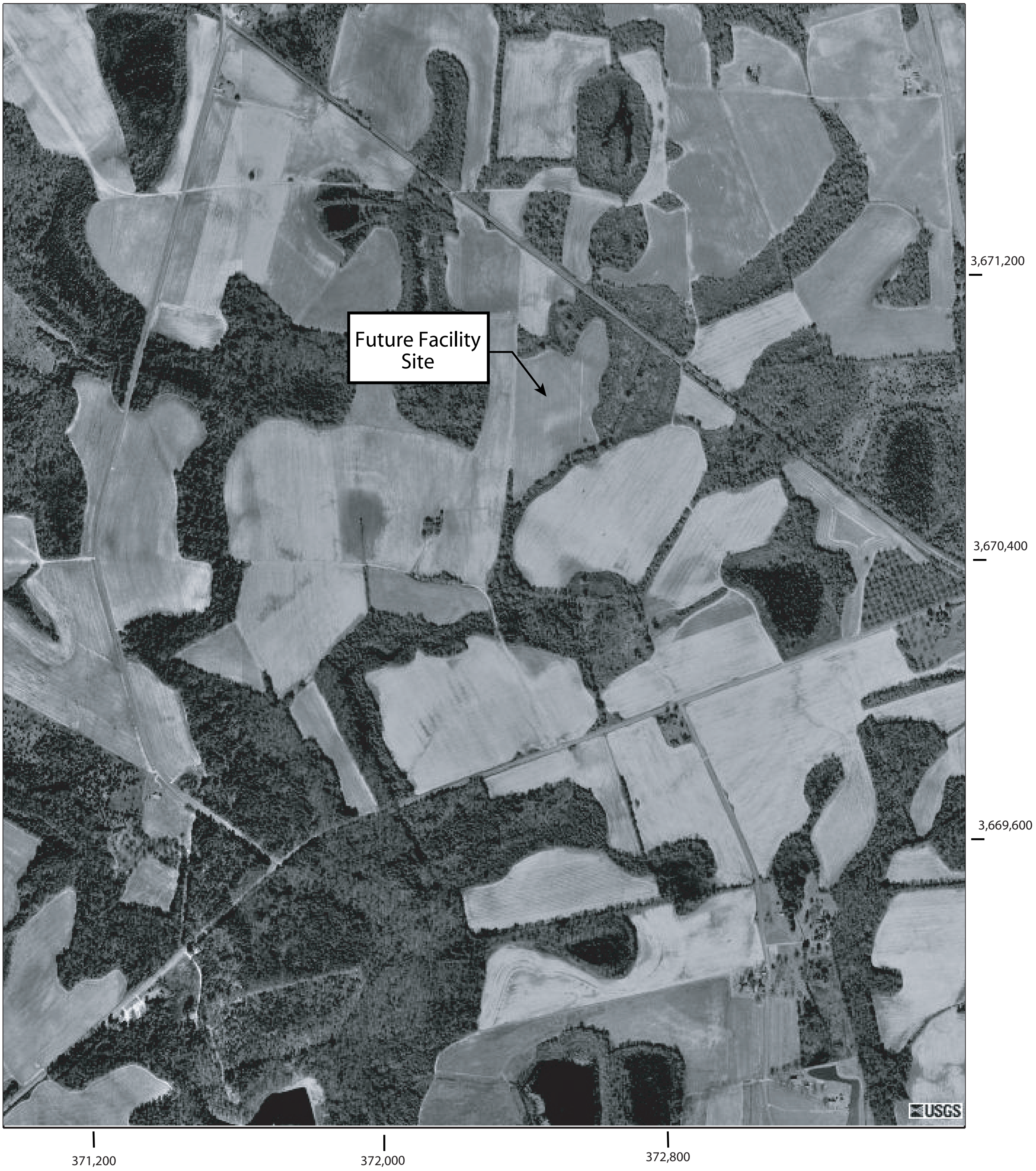
The BACT analysis for the facility natural gas boilers clearly demonstrated that emission controls would not be effective for these units. With only approximately 0.1 tpy of total HAPs estimated from each natural gas boiler, an annualized control equipment cost of only $1,000 would produce a cost effectiveness of $10,000 per ton, assuming all expected HAPs emitted by the boilers were controlled. Therefore, no emission controls are necessary for sources of this type, as also determined by EPA in development of the March 21, 2011 Rule.

6.6.5 STEP 5 – MACT EMISSIONS LIMITATION

In conjunction with the March 21, 2011 Rule, MACT for the natural gas boilers is defined as a work practice standard, by conducting a tune-up of the boiler or process heater biennially. The tune-up will be conducted as specified in 40 CFR 63.7540 of the March 21, 2011 Rule.

APPENDIX A – AREA MAP AND PLOT PLAN

Pyramax Kings Mill Site

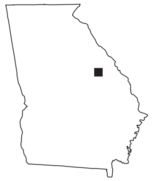


Edge markings in UTM coordinates (meters)

Scale

0 400 800

Meters



USGS Aerial Photograph
February 6, 1999
(UTM Zone 17)

Trinity Consultants

STORM PIPE SCHEDULE

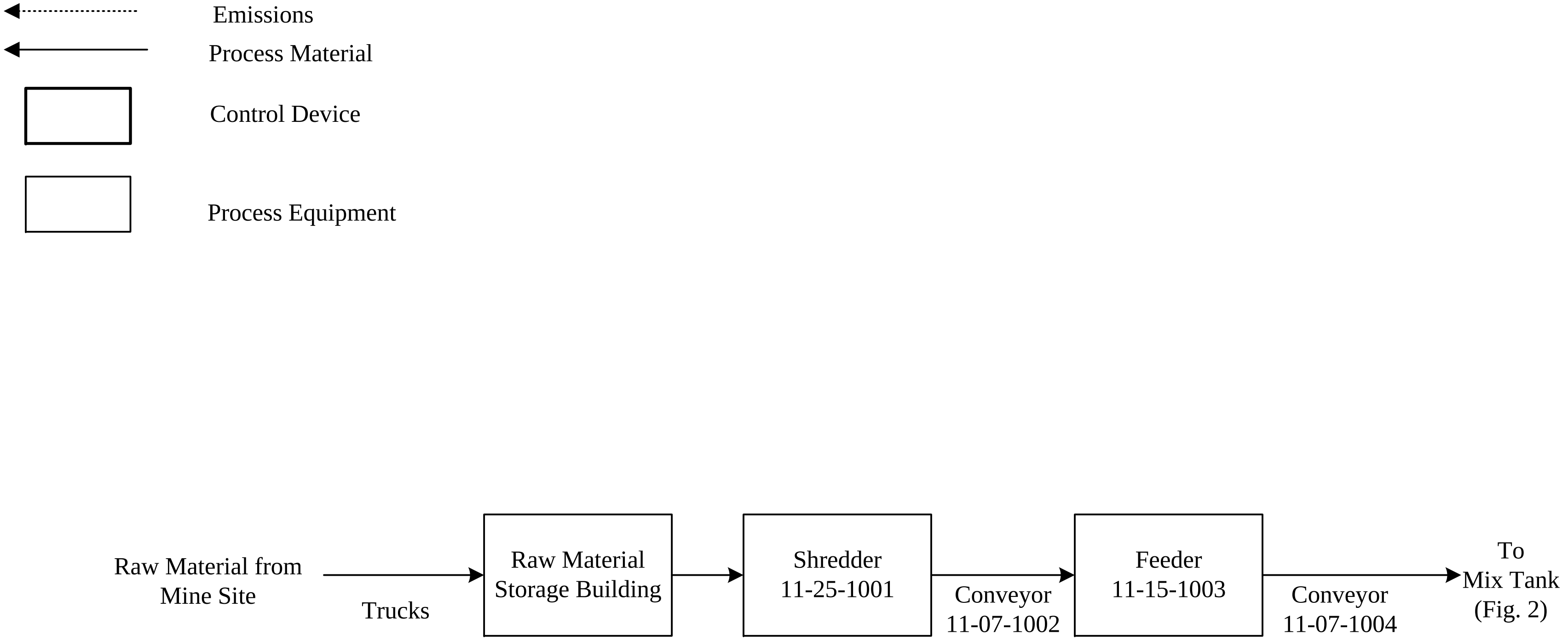
Ⓐ	40 LF – 18" RCP STORM DRAIN @ 0.50% SLOPE
Ⓑ	41 LF – 24" RCP STORM DRAIN @ 0.50% SLOPE
Ⓒ	38 LF – 36" RCP STORM DRAIN @ 0.50% SLOPE
Ⓓ	81 LF – 36" RCP STORM DRAIN @ 0.50% SLOPE
Ⓔ	70 LF – 42" RCP STORM DRAIN @ 0.50% SLOPE
Ⓕ	81 LF – 60" RCP STORM DRAIN @ 0.50% SLOPE
Ⓖ	114 LF – 72" RCP STORM DRAIN @ 0.50% SLOPE
Ⓗ	44 LF – 36" RCP STORM DRAIN @ 0.50% SLOPE
Ⓘ	133 LF – 36" RCP STORM DRAIN @ 0.50% SLOPE
Ⓙ	245 LF – 36" RCP STORM DRAIN @ 0.50% SLOPE
Ⓚ	64 LF – 48" RCP STORM DRAIN @ 0.50% SLOPE
Ⓛ	140 LF – 48" RCP STORM DRAIN @ 0.50% SLOPE
Ⓜ	312 LF – 24" RCP STORM DRAIN @ 0.50% SLOPE
Ⓝ	64 LF – 24" RCP STORM DRAIN @ 0.50% SLOPE
Ⓟ	154 LF – 36" RCP STORM DRAIN @ 0.50% SLOPE

NOTE: ALL DITCHES ARE TO SLOPE AT 0.50%

STANDARD LEGEND

DESCRIPTION	PROPOSED
CONCRETE	∴
ASPHALT– HEAVY DUTY	▩
ASPHALT– LIGHT DUTY	⋯
GRASS/LANDSCAPING	↓
GRAVEL	⬡

APPENDIX B – PROCESS FLOW DIAGRAMS



PyraMax Ceramics LLC
Light Weight Proppant Plant

Figure 1
Clay Benefaction

Trinity Consultants

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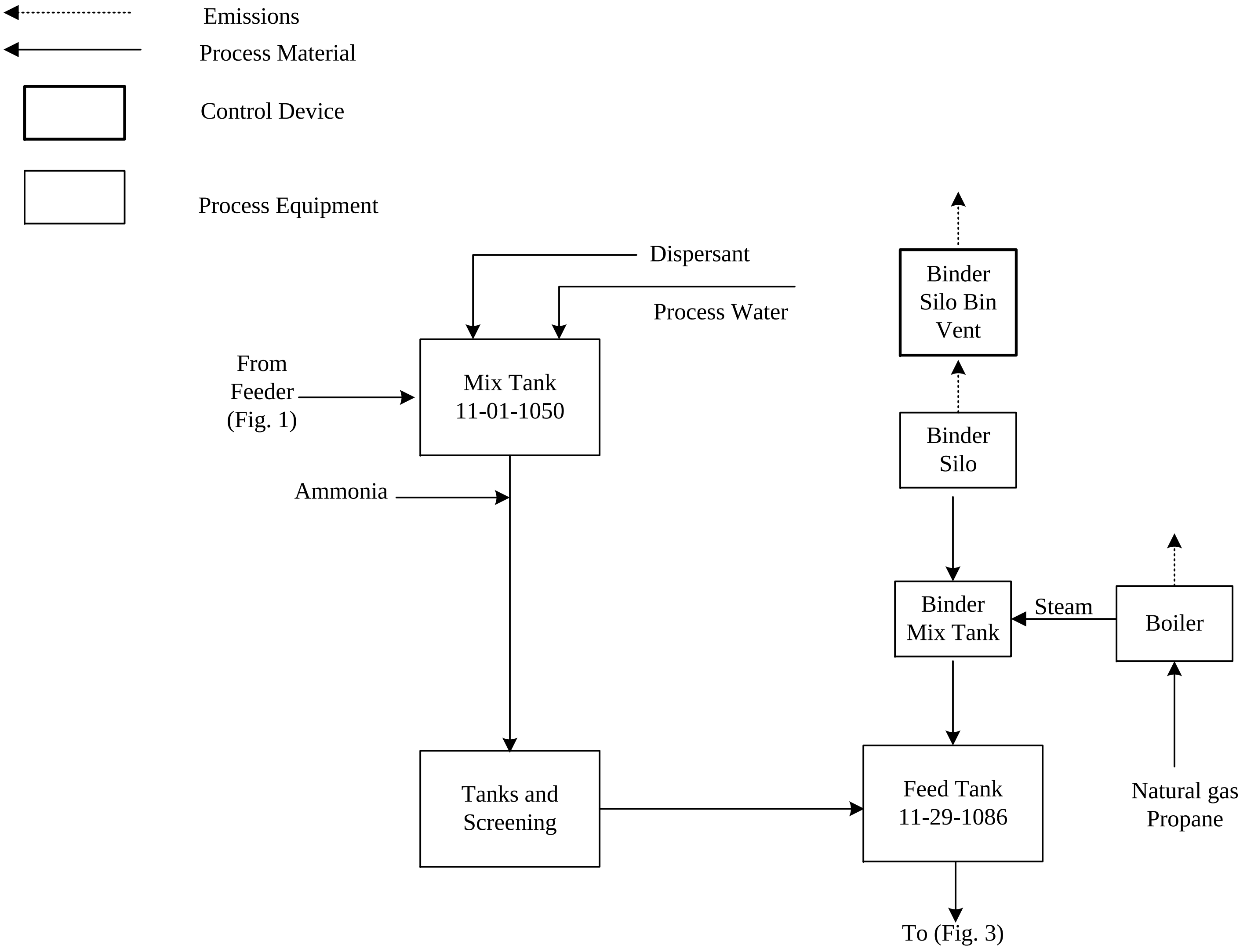
July 2011



PyraMax Ceramics LLC
Light Weight Proppant Plant

Figure 2
Feedstock Preparation

Trinity Consultants

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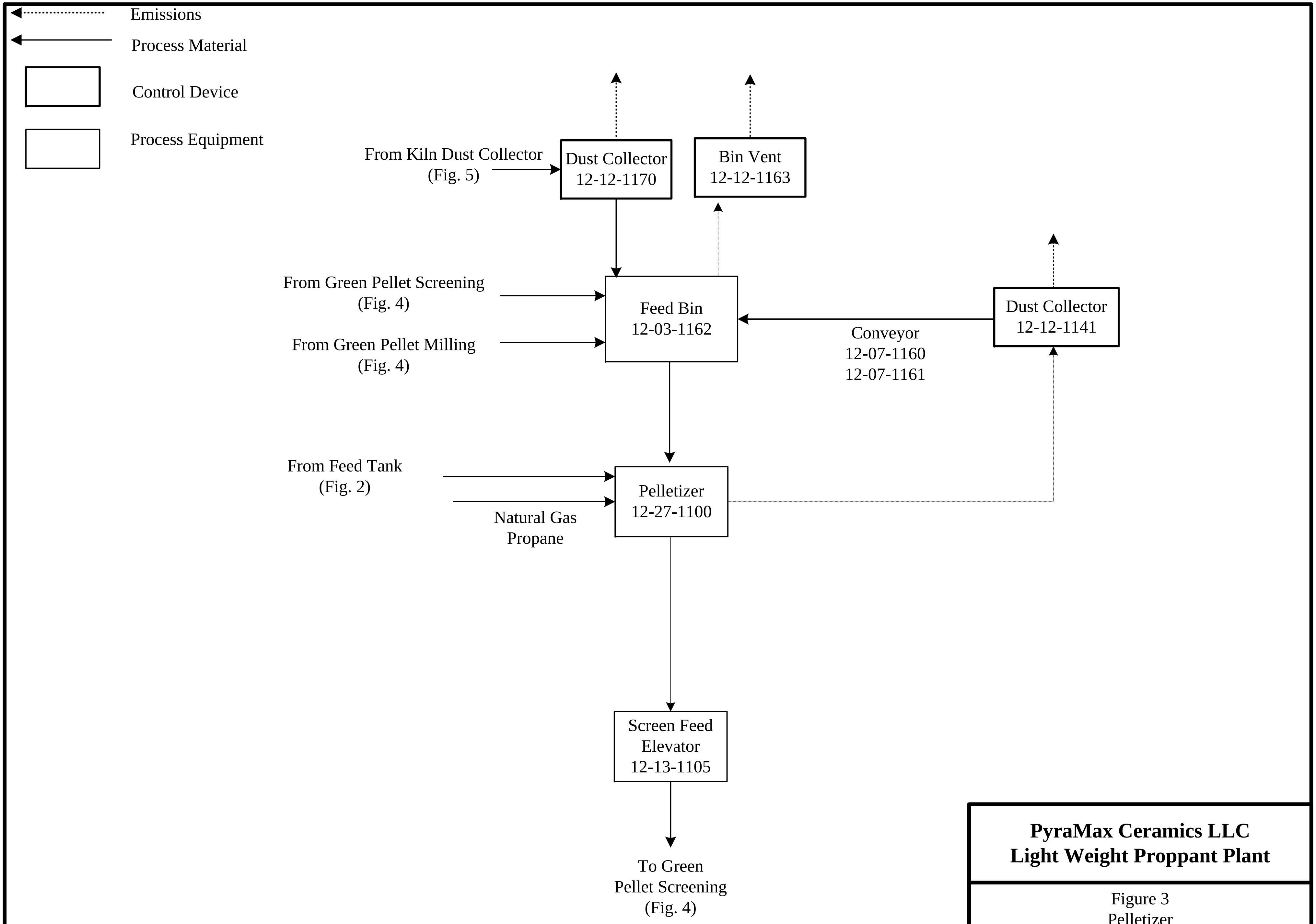
July 2011



PyraMax Ceramics LLC
Light Weight Proppant Plant

Figure 3
Pelletizer

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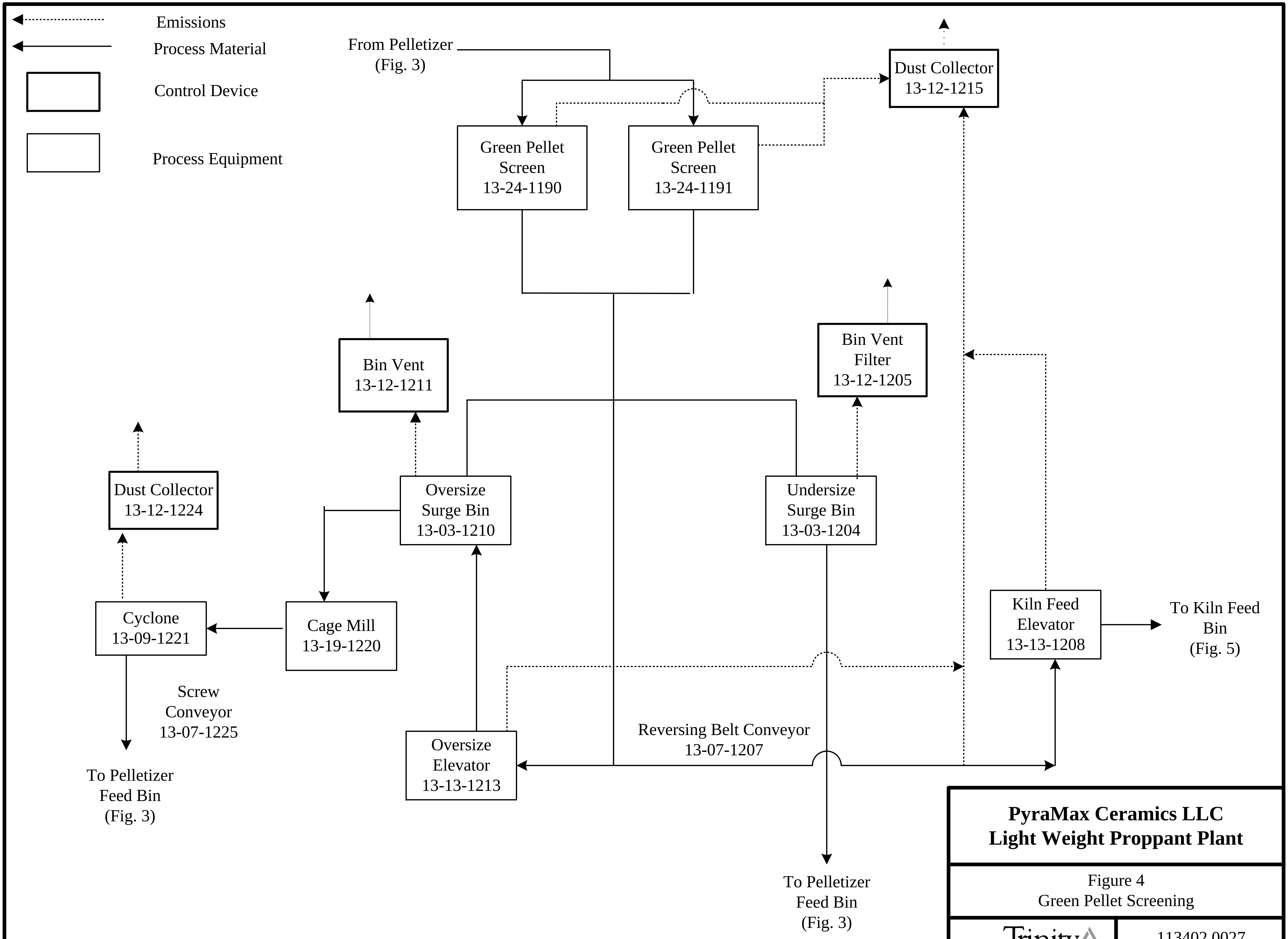

PyraMax Ceramics LLC
Light Weight Proppant Plant

Figure 4
Green Pellet Screening

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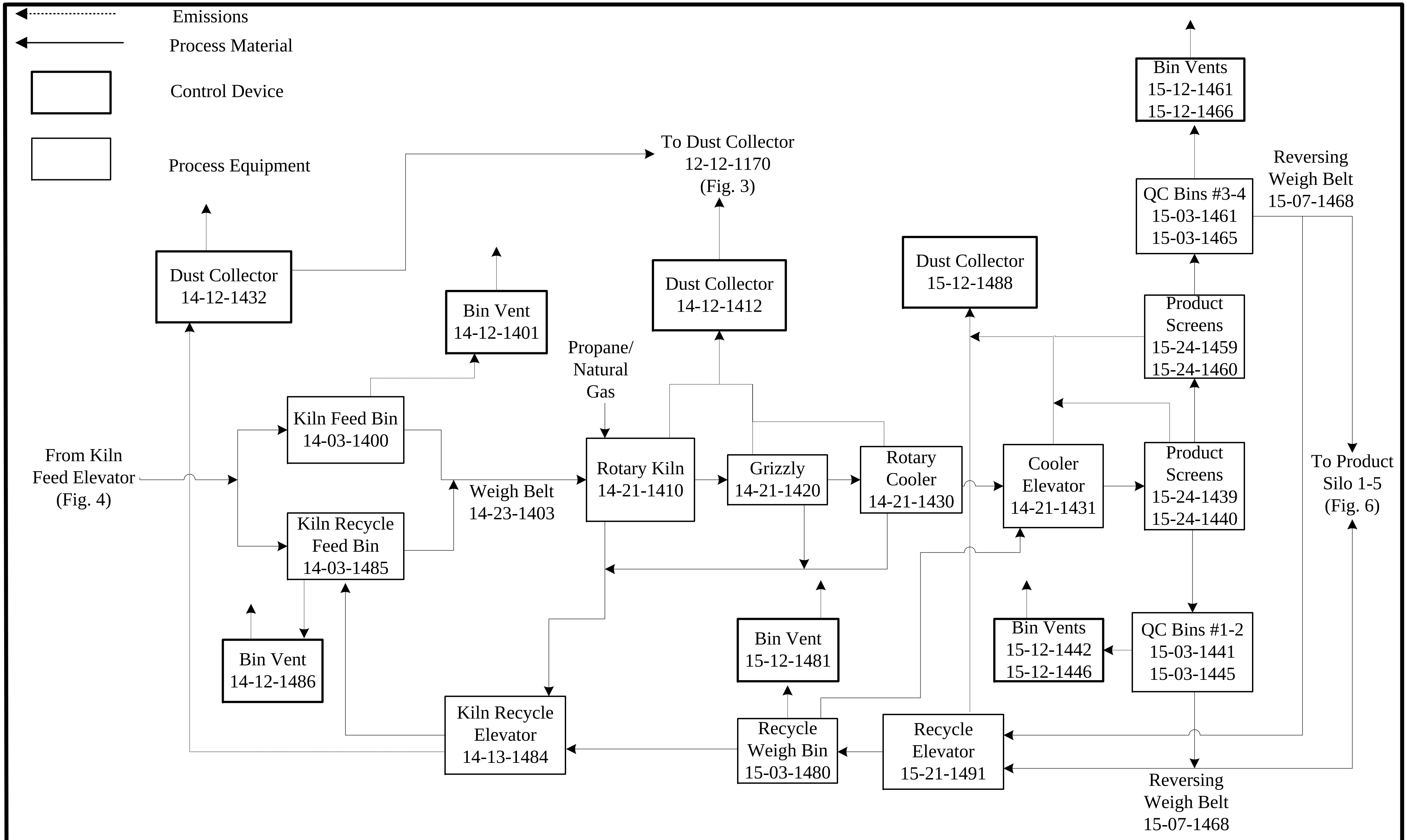
July 2011



PyraMax Ceramics LLC
Light Weight Proppant Plant

Figure 5
Rotary Kiln

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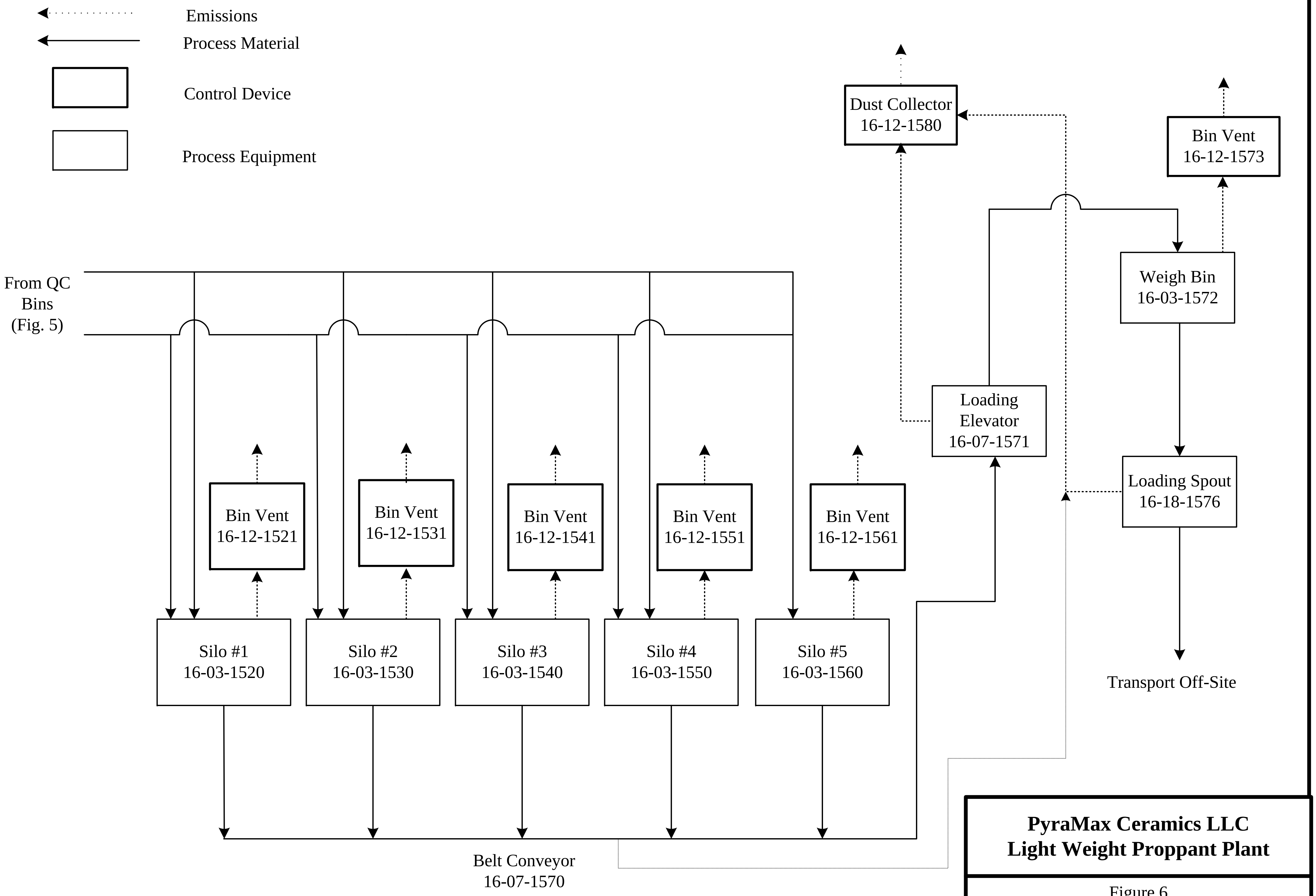
July 2011



PyraMax Ceramics LLC
Light Weight Proppant Plant

Figure 6
Storage and Loading

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113402.0027
July 2011

APPENDIX C – DETAILED EMISSIONS CALCULATIONS

PyraMax Ceramics
Emission Calculations

Table C-1. Combustion Unit Parameters

Emission Unit ID	Emission Source	Capacity[b]	Units
14-21-1410	Kiln 1	49.3	MMBtu/hr
24-21-1410	Kiln 2	49.3	MMBtu/hr
12-27-1100	Pelletizer 1	75	MMBtu/hr
22-27-1100	Pelletizer 2	75	MMBtu/hr
17-XX-XXX	Boiler 1	9.8	MMBtu/hr
27-XX-XXX	Boiler 2	9.8	MMBtu/hr
17-XX-XXX	Generator 1 - consists of two engines	500	kW/engine
27-XX-XXX	Generator 2 - consists of two engines	500	kW/engine

[a] Assumes 1% scrap

[b] Process rates from "Preliminary PyraMax Emission Units 6-2-11.xls" downloaded from Sharepoint site on 6/6/11. Throughputs are based on the +20% design values.

Table C-2. Emissions Summary

Emission Unit Description	**Emission Unit ID**	**Emission Point ID**	**PM**		**PM_{10}**		**$PM_{2.5}$**		**SO_2**		**NO_X**		**CO**		**VOC**		**CO_2e**		**Fluorides**	
			lb/hr	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**
Feed Bin	12-03-1162	12-12-1163	2.31E-03	0.01	2.31E-03	0.01	1.22E-03	5.34E-03												
Kiln Dust Recycle to Feed Bin	14-07-1410	12-12-1170	0.03	0.14	0.03	0.14	0.02	0.07												
Additive Silos - Line 1&2		PVA1	0.02	0.09	0.02	0.09	0.01	0.05							75.21	13.73				
Pelletizer Conveyor under Pelletizer, Conveyor to Feed Bin, Elevator to Green Pellet Screening	12-27-1100, 12-07-1160, 12-07-1161, 12-13-1105	12-12-1141	7.70	33.72	7.70	33.72	4.26	18.64	0.05	0.20	2.25	9.86	13.73	60.12	11.78	51.59	10,147.52	44,446.13		
Feed Bin	22-03-1162	22-12-1163	2.31E-03	0.01	2.31E-03	0.01	1.22E-03	5.34E-03												
Kiln Dust Recycle to Feed Bin	24-07-1410	22-12-1170	0.03	0.14	0.03	0.14	0.02	0.07												
Pelletizer, Conveyor under Pelletizer, Conveyor to Feed Bin, Elevator to Green Pellet Screening	22-27-1100, 22-07-1160, 22-07-1161, 22-13-1105	22-12-1141	7.70	33.72	7.70	33.72	4.26	18.64	0.05	0.20	2.25	9.86	13.73	60.12	11.78	51.59	10,147.52	44,446.13		
Green Pellet Screen #1, Green Pellet Screen #2, Oversize Elevator, Reversing Belt Conveyor, Kiln Feed Elevator	13-24-1190, 13-24-1191, 13-13-1213, 13-07-1207, 13-13-1208	13-12-1215	0.32	1.41	0.32	1.41	0.17	0.74												
Cage Mill, Cyclone, Screw Conveyor	13-19-1220, 13-09-1221, 13-07-1225	13-12-1224	7.71E-04	3.38E-03	7.71E-04	3.38E-03	4.06E-04	1.78E-03												
Green Pellet Screen #1, Green Pellet Screen #2, Oversize Elevator, Reversing Belt Conveyor, Kiln Feed Elevator	23-24-1190, 23-24-1191, 23-13-1213, 23-07-1207, 23-13-1208	23-12-1215	0.32	1.41	0.32	1.41	0.17	0.74												
Cage Mill, Cyclone, Screw Conveyor	23-19-1220, 23-09-1221, 23-07-1225	23-12-1224	7.71E-04	3.38E-03	7.71E-04	3.38E-03	4.06E-04	1.78E-03												
Kiln Recycle Feed Bin	14-03-1485	14-12-1486	0.01	0.05	0.01	0.05	5.46E-03	0.02												
Kiln, Kiln Cooler, Grizzly	14-21-1410, 14-21-1430, 14-21-1420	14-12-1412	8.53	37.37	8.53	37.37	6.98	30.58	11.64	51.00	36.30	158.99	55.50	243.08	0.54	2.36	7,637.92	33,454.09	0.02	0.09
Kiln Recycle Feed Bin	24-03-1485	24-12-1486	0.01	0.05	0.01	0.05	5.46E-03	0.02												
Kiln, Kiln Cooler, Grizzly	24-21-1410, 24-21-1430, 24-21-1420	24-12-1412	8.53	37.37	8.53	37.37	6.98	30.58	11.64	51.00	36.30	158.99	55.50	243.08	0.54	2.36	7,637.92	33,454.09	0.02	0.09
Cooler Elevator, Final Product Screen #1, Final Product Screen #2, Final Product Screen #3, Final Product Screen #4, Reversing Weigh Belt, Reversing Weigh Belt, Recycle Elevator	14-21-1431, 15-24-1439, 15-24-1440, 15-24-1459, 15-24-1460, 15-07-1448, 15-07-1468, 15-21-1491	15-12-1488	0.37	1.62	0.37	1.62	0.20	0.85												
Cooler Elevator, Final Product Screen #1, Final Product Screen #2, Final Product Screen #3, Final Product Screen #4, Reversing Weigh Belt, Reversing Weigh Belt, Recycle Elevator	24-21-1431, 25-24-1439, 25-24-1440, 25-24-1459, 25-24-1460, 25-07-1448, 25-07-1468, 25-21-1491	25-12-1488	0.37	1.62	0.37	1.62	0.20	0.85												
Silo #1	16-03-1520	16-12-1521	0.01	0.05	0.01	0.05	5.41E-03	0.02												
Silo #2	16-03-1530	16-12-1531	0.01	0.05	0.01	0.05	5.41E-03	0.02												
Silo #3	16-03-1540	16-12-1541	0.01	0.05	0.01	0.05	5.41E-03	0.02												
Silo #4	16-03-1550	16-12-1551	0.01	0.05	0.01	0.05	5.41E-03	0.02												
Silo #5	16-03-1560	16-12-1561	0.01	0.05	0.01	0.05	5.41E-03	0.02												
Weigh Bin	16-03-1572	16-12-1573	1.71E-03	7.51E-03	1.71E-03	7.51E-03	9.02E-04	3.95E-03												
Belt Conveyor, Loading Elevator, Loading Spout	16-07-1570, 16-07-1571, 16-18-1576	16-12-1580	0.69	3.02	0.69	3.02	0.36	1.59												
Silo #1	26-03-1520	26-12-1521	0.01	0.05	0.01	0.05	5.41E-03	0.02												
Silo #2	26-03-1530	26-12-1531	0.01	0.05	0.01	0.05	5.41E-03	0.02												
Silo #3	26-03-1540	26-12-1541	0.01	0.05	0.01	0.05	5.41E-03	0.02												
Silo #4	26-03-1550	26-12-1551	0.01	0.05	0.01	0.05	5.41E-03	0.02												
Silo #5	26-03-1560	26-12-1561	0.01	0.05	0.01	0.05	5.41E-03	0.02												
Weigh Bin	26-03-1572	26-12-1573	1.71E-03	7.51E-03	1.71E-03	7.51E-03	9.02E-04	3.95E-03												
Belt Conveyor, Loading Elevator, Loading Spout	26-07-1570, 26-07-1571, 26-18-1576	26-12-1580	0.69	3.02	0.69	3.02	0.36	1.59												
Sodium bicarbonate silo		S1a	0.02	0.09	0.02	0.09	0.01	0.05												
Fly Ash Silo		S1b	0.09	0.38	0.09	0.38	0.05	0.20												
Sodium bicarbonate silo		S2a	0.02	0.09	0.02	0.09	0.01	0.05												
Fly Ash Silo		S2b	0.09	0.38	0.09	0.38	0.05	0.20												
Boiler - Line 1	17-XX-XXX	B1	0.07	0.33	0.07	0.33	0.07	0.33	5.88E-03	0.03	1.39	6.10	0.11	0.47	0.82	3.61	1,325.94	5,807.63		
Boiler - Line 2	27-XX-XXX	B2	0.07	0.33	0.07	0.33	0.07	0.33	5.88E-03	0.03	1.39	6.10	0.11	0.47	0.82	3.61	1,325.94	5,807.63		
Generator - Line 1	17-XX-XXX		0.44	0.02	0.44	0.02	0.44	0.02	2.75	0.14	8.82	0.44	7.72	0.39	8.82	0.44	1,534.58	76.73		
Generator - Line 2	27-XX-XXX		0.44	0.02	0.44	0.02	0.44	0.02	2.75	0.14	8.82	0.44	7.72	0.39	8.82	0.44	1,534.58	76.73		
Diesel Storage Tanks															1.21E-03	5.32E-03				
Totals			**36.69**	**156.88**	**36.69**	**156.88**	**25.19**	**106.52**	**28.88**	**102.71**	**97.52**	**350.78**	**154.09**	**608.10**	**119.13**	**129.73**	**41,291.92**	**167,569.15**	**0.04**	**0.19**

Table C-3. HAP and TAP Emissions Summary

	Kiln 1 14-21-1410		Kiln 2 24-21-1410		Pelletizer 1 12-27-1100		Pelletizer 2 22-27-1100		Additive Silo 1/2		Boiler 1		Boiler 2		Total	
Pollutant	**lb/hr**	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**
Benzene	1.04E-04	4.53E-04	1.04E-04	4.53E-04	1.58E-04	6.90E-04	1.58E-04	6.90E-04			2.06E-05	9.01E-05	2.06E-05	9.01E-05	5.63E-04	2.47E-03
Dichlorobenzene	5.92E-05	2.59E-04	5.92E-05	2.59E-04	9.00E-05	3.94E-04	9.00E-05	3.94E-04			1.18E-05	5.15E-05	1.18E-05	5.15E-05	3.22E-04	1.41E-03
Formaldehyde	3.70E-03	1.62E-02	3.70E-03	1.62E-02	5.63E-03	2.46E-02	5.63E-03	2.46E-02			7.35E-04	3.22E-03	7.35E-04	3.22E-03	2.01E-02	8.81E-02
n-Hexane	8.87E-02	3.89E-01	8.87E-02	3.89E-01	1.35E-01	5.91E-01	1.35E-01	5.91E-01			1.76E-02	7.73E-02	1.76E-02	7.73E-02	4.83E-01	2.11E+00
Naphthalene	3.01E-05	1.32E-04	3.01E-05	1.32E-04	4.58E-05	2.00E-04	4.58E-05	2.00E-04			5.98E-06	2.62E-05	5.98E-06	2.62E-05	1.64E-04	7.17E-04
Selenium	1.18E-06	5.18E-06	1.18E-06	5.18E-06	1.80E-06	7.88E-06	1.80E-06	7.88E-06			2.35E-07	1.03E-06	2.35E-07	1.03E-06	6.44E-06	2.82E-05
Toluene	1.68E-04	7.34E-04	1.68E-04	7.34E-04	2.55E-04	1.12E-03	2.55E-04	1.12E-03			3.33E-05	1.46E-04	3.33E-05	1.46E-04	9.12E-04	3.99E-03
POM	4.35E-06	1.90E-05	4.35E-06	1.90E-05	6.62E-06	2.90E-05	6.62E-06	2.90E-05			8.64E-07	3.79E-06	8.64E-07	3.79E-06	2.37E-05	1.04E-04
Arsenic	9.86E-06	4.32E-05	9.86E-06	4.32E-05	1.50E-05	6.57E-05	1.50E-05	6.57E-05			1.96E-06	8.58E-06	1.96E-06	8.58E-06	5.36E-05	2.35E-04
Beryllium	5.92E-07	2.59E-06	5.92E-07	2.59E-06	9.00E-07	3.94E-06	9.00E-07	3.94E-06			1.18E-07	5.15E-07	1.18E-07	5.15E-07	3.22E-06	1.41E-05
Cadmium	5.42E-05	2.38E-04	5.42E-05	2.38E-04	8.25E-05	3.61E-04	8.25E-05	3.61E-04			1.08E-05	4.72E-05	1.08E-05	4.72E-05	2.95E-04	1.29E-03
Chromium	6.90E-05	3.02E-04	6.90E-05	3.02E-04	1.05E-04	4.60E-04	1.05E-04	4.60E-04			1.37E-05	6.01E-05	1.37E-05	6.01E-05	3.75E-04	1.64E-03
Cobalt	4.14E-06	1.81E-05	4.14E-06	1.81E-05	6.30E-06	2.76E-05	6.30E-06	2.76E-05			8.23E-07	3.61E-06	8.23E-07	3.61E-06	2.25E-05	9.87E-05
Lead	2.47E-05	1.08E-04	2.47E-05	1.08E-04	3.75E-05	1.64E-04	3.75E-05	1.64E-04			4.90E-06	2.15E-05	4.90E-06	2.15E-05	1.34E-04	5.87E-04
Manganese	1.87E-05	8.21E-05	1.87E-05	8.21E-05	2.85E-05	1.25E-04	2.85E-05	1.25E-04			3.72E-06	1.63E-05	3.72E-06	1.63E-05	1.02E-04	4.46E-04
Mercury	1.28E-05	5.61E-05	1.28E-05	5.61E-05	1.95E-05	8.54E-05	1.95E-05	8.54E-05			2.55E-06	1.12E-05	2.55E-06	1.12E-05	6.97E-05	3.05E-04
Nickel	1.04E-04	4.53E-04	1.04E-04	4.53E-04	1.58E-04	6.90E-04	1.58E-04	6.90E-04			2.06E-05	9.01E-05	2.06E-05	9.01E-05	5.63E-04	2.47E-03
Methanol					5.48	24.00	5.48	24.00	30.15	5.50					4.11E+01	5.35E+01
Methyl Acetate					5.48	24.00	5.48	24.00	45.06	8.22					5.60E+01	5.62E+01
Hydrogen Fluoride	1.03	4.52	1.03	4.52											2.06E+00	9.04E+00
Hydrogen Chloride	0.67	2.94	0.67	2.94											1.34E+00	5.89E+00
Ammonia	0.02	0.09	0.02	0.09	122.71	537.45	122.71	537.45							2.45E+02	1.08E+03

Table C-4. Particulate Matter Controlled Emissions from Baghouses

Process Area	Emission Unit IDs		Dust Collector ID	Dust Collector Description	Outlet Grain Loading Rate	Flow Rate	Emissions					
							PM		PM$_{10}$		PM$_{2.5}$	
					(gr/dscf)[a]	(dscfm)	(lb/hr)	(tpy)[b]	(lb/hr)	(tpy)[b,c]	(lb/hr)	(tpy)[b,c]
Pelletization - Line 1	12-03-1162	Feed Bin	12-12-1163	Feed Bin Vent Filter	0.005	54	2.31E-03	0.01	2.31E-03	0.01	1.22E-03	5.34E-03
	14-07-1410	Kiln Dust Recycle to Feed Bin	12-12-1170	Baghouse- for dust from kiln baghouse to Feed Bin	0.005	750	0.03	0.14	0.03	0.14	0.02	0.07
		Additive Silos - Line 1&2		Additive silo bin vent	0.005	500	0.02	0.09	0.02	0.09	0.01	0.05
	12-27-1100, 12-07-1160, 12-07-1161, 12-13-1105	Pelletizer Conveyor under Pelletizer, Conveyor to Feed Bin, Elevator to Green Pellet Screening	12-12-1141	Baghouse for pelletizer	0.01	89,820	7.70	33.72	7.70	33.72	4.26	18.64
Pelletization - Line 2	22-03-1162	Feed Bin	22-12-1163	Feed Bin Vent Filter	0.005	54	2.31E-03	0.01	2.31E-03	0.01	1.22E-03	5.34E-03
	24-07-1410	Kiln Dust Recycle to Feed Bin	22-12-1170	Baghouse- for dust from kiln baghouse to Feed Bin	0.005	750	0.03	0.14	0.03	0.14	0.02	0.07
	22-27-1100, 22-07-1160, 22-07-1161, 22-13-1105	Pelletizer, Conveyor under Pelletizer, Conveyor to Feed Bin, Elevator to Green Pellet Screening	22-12-1141	Baghouse for pelletizer	0.01	89,820	7.70	33.72	7.70	33.72	4.26	18.64
Green Screening - Line 1	13-24-1190, 13-24-1191, 13-13-1213, 13-07-1207, 13-13-1208	Green Pellet Screen #1, Green Pellet Screen #2, Oversize Elevator, Reversing Belt Conveyor, Kiln Feed Elevator	13-12-1215	Baghouse for Green Pellet Screening	0.005	7,488	0.32	1.41	0.32	1.41	0.17	0.74
	13-19-1220, 13-09-1221, 13-07-1225	Cage Mill, Cyclone, Screw Conveyor	13-12-1224	Baghouse for Dry Milling	0.005	18	7.71E-04	3.38E-03	7.71E-04	3.38E-03	4.06E-04	1.78E-03
Green Screening - Line 2	23-24-1190, 23-24-1191, 23-13-1213, 23-07-1207, 23-13-1208	Green Pellet Screen #1, Green Pellet Screen #2, Oversize Elevator, Reversing Belt Conveyor, Kiln Feed Elevator	23-12-1215	Baghouse for Green Pellet Screening	0.005	7,488	0.32	1.41	0.32	1.41	0.17	0.74
	23-19-1220, 23-09-1221, 23-07-1225	Cage Mill, Cyclone, Screw Conveyor	23-12-1224	Baghouse for Dry Milling	0.005	18	7.71E-04	3.38E-03	7.71E-04	3.38E-03	4.06E-04	1.78E-03
Calcining and Sintering - Line 1	14-03-1485	Kiln Recycle Feed Bin	14-12-1486	Kiln Recycle Feed Bin Vent Filter	0.005	242	0.01	0.05	0.01	0.05	5.46E-03	0.02
	14-21-1410, 14-21-1430, 14-21-1420	Kiln, Kiln Cooler, Grizzly	14-12-1412	Kiln Baghouse	0.01	40,434	3.47	15.18	3.47	15.18	1.92	8.39
Calcining and Sintering - Line 2	24-03-1485	Kiln Recycle Feed Bin	24-12-1486	Kiln Recycle Feed Bin Vent Filter	0.005	242	0.01	0.05	0.01	0.05	5.46E-03	0.02
	24-21-1410, 24-21-1430, 24-21-1420	Kiln, Kiln Cooler, Grizzly	24-12-1412	Kiln Baghouse	0.01	40,434	3.47	15.18	3.47	15.18	1.92	8.39
Product Screening - Line 1	14-21-1431, 15-24-1439, 15-24-1440, 15-24-1459, 15-24-1460, 15-07-1448, 15-07-1468, 15-21-1491	Cooler Elevator, Final Product Screen #1, Final Product Screen #2, Final Product Screen #3, Final Product Screen #4, Reversing Weigh Belt, Reversing Weigh Belt, Recycle Elevator	15-12-1488	Baghouse for Final Product Screening and QC	0.005	8,653	0.37	1.62	0.37	1.62	0.20	0.85
Product Screening - Line 2	24-21-1431, 25-24-1439, 25-24-1440, 25-24-1459, 25-24-1460, 25-07-1448, 25-07-1468, 25-21-1491	Cooler Elevator, Final Product Screen #1, Final Product Screen #2, Final Product Screen #3, Final Product Screen #4, Reversing Weigh Belt, Reversing Weigh Belt, Recycle Elevator	25-12-1488	Baghouse for Final Product Screening and QC	0.005	8,653	0.37	1.62	0.37	1.62	0.20	0.85
Shipping - Line 1	16-03-1520	Silo #1	16-12-1521	Silo #1 Bin Vent Filter	0.005	240	0.01	0.05	0.01	0.05	5.41E-03	0.02
	16-03-1530	Silo #2	16-12-1531	Silo #2 Bin Vent Filter	0.005	240	0.01	0.05	0.01	0.05	5.41E-03	0.02
	16-03-1540	Silo #3	16-12-1541	Silo #3 Bin Vent Filter	0.005	240	0.01	0.05	0.01	0.05	5.41E-03	0.02
	16-03-1550	Silo #4	16-12-1551	Silo #4 Bin Vent Filter	0.005	240	0.01	0.05	0.01	0.05	5.41E-03	0.02
	16-03-1560	Silo #5	16-12-1561	Silo #5 Bin Vent Filter	0.005	240	0.01	0.05	0.01	0.05	5.41E-03	0.02
	16-03-1572	Weigh Bin	16-12-1573	Weigh Bin Vent Filter	0.005	40	1.71E-03	7.51E-03	1.71E-03	7.51E-03	9.02E-04	3.95E-03
	16-07-1570, 16-07-1571, 16-18-1576	Belt Conveyor, Loading Elevator, Loading Spout	16-12-1580	Baghouse for Loading Operations	0.005	16,096	0.69	3.02	0.69	3.02	0.36	1.59
Shipping - Line 2	26-03-1520	Silo #1	26-12-1521	Silo #1 Bin Vent Filter	0.005	240	0.01	0.05	0.01	0.05	5.41E-03	0.02
	26-03-1530	Silo #2	26-12-1531	Silo #2 Bin Vent Filter	0.005	240	0.01	0.05	0.01	0.05	5.41E-03	0.02
	26-03-1540	Silo #3	26-12-1541	Silo #3 Bin Vent Filter	0.005	240	0.01	0.05	0.01	0.05	5.41E-03	0.02
	26-03-1550	Silo #4	26-12-1551	Silo #4 Bin Vent Filter	0.005	240	0.01	0.05	0.01	0.05	5.41E-03	0.02
	26-03-1560	Silo #5	26-12-1561	Silo #5 Bin Vent Filter	0.005	240	0.01	0.05	0.01	0.05	5.41E-03	0.02
	26-03-1572	Weigh Bin	26-12-1573	Weigh Bin Vent Filter	0.005	40	1.71E-03	7.51E-03	1.71E-03	7.51E-03	9.02E-04	3.95E-03
	26-07-1570, 26-07-1571, 26-18-1576	Belt Conveyor, Loading Elevator, Loading Spout	26-12-1580	Baghouse for Loading Operations	0.005	16,096	0.69	3.02	0.69	3.02	0.36	1.59
Control System - Line 1		Sodium bicarbonate silo		Sodium bicarbonate silo bin vent filter	0.005	500	0.02	0.09	0.02	0.09	0.01	0.05
		Fly Ash Silo		Fly Ash Silo bin vent filter	0.005	2,000	0.09	0.38	0.09	0.38	0.05	0.20
Control System - Line 2		Sodium bicarbonate silo		Sodium bicarbonate silo bin vent filter	0.005	500	0.02	0.09	0.02	0.09	0.01	0.05
		Fly Ash Silo		Fly Ash Silo bin vent filter	0.005	2,000	0.09	0.38	0.09	0.38	0.05	0.20
							25.31	**110.86**	**25.31**	**110.86**	**13.92**	**60.95**

[a] Conversion factor of 7,000 grains per pound used.

[b] Potential annual emissions are based on facility operating 8,760 hours per year.

[c] PyraMax assumed all PM was PM$_{10}$. For PM2.5 speciation, PyraMax used the following ratios:

55.29% EPA AP-42 Table 11.25-4 for flash calciner controlled by fabric filter. Ratio assumed for both the kiln and pelletizer baghouses.

52.63% determined from EPA's "PM Calculator" on http://www.epa.gov/ttn/chief/eiinformation.html for SCC 30500711 (cement wet process screening) and 30500719 (cement load out). The value is a ratio of the controlled PM$_{2.5}$ and PM$_{10}$ emissions.
The value is a ratio of the controlled PM$_{2.5}$ and PM$_{10}$ emissions.

Table C-5. Combustion Input Parameters

Heating Value of Natural Gas[a]	1,000	Btu/ft^3
Heating Value of Propane[b]	91.5	MMBtu/1,000 gal
Potential Hours of Operation on Natural Gas	8,760	Hours
Potential Hours of Operation on Propane	8,760	Hours
Sulfur Content of Propane	0.18	gr/100 ft^3

[a] From process flow diagrams downloaded from Sharepoint site on 6-6-11.

[b] AP-42, 5th Edition, Table 1.5-1 (07/08) footnote b.

Table C-6. Combustion Emission Factors

Pollutant	**Natural Gas Emission Factor[a] (lb/MMft^3)**	**Propane Emission Factor[f] (lb/10^3 gal)**
Criteria		
PM	7.6	0.7
PM$_{10}$	7.6	0.7
PM$_{2.5}$	7.6	0.7
SO$_2$[b]	0.6	0.018
NO$_X$[c]	50	13
VOC	5.5	1
CO	84	7.5
HAP/TAP Emissions		
Benzene	2.10E-03	no HAPs or TAPs specified in AP-42
Dichlorobenzene	1.20E-03	
Formaldehyde	7.50E-02	
n-Hexane	1.80E+00	
Naphthalene	6.10E-04	
Selenium	2.40E-05	
Toluene	3.40E-03	
POM[d]	8.82E-05	
Arsenic	2.00E-04	
Beryllium	1.20E-05	
Cadmium	1.10E-03	
Chromium	1.40E-03	
Cobalt	8.40E-05	
Lead	5.00E-04	
Manganese	3.80E-04	
Mercury	2.60E-04	
Nickel	2.10E-03	
Greenhouse Gases[e]		
CO$_2$	120,161	12,330
CH$_4$	2.27	0.60
N$_2$O	0.23	0.12

[a] Emission factors are from AP-42, 5th Edition, Section 1.4 (7/98).

[b] Emission factor for SO$_2$ calculated based AP-42, 5th Edition, Section 1.5 (07/08) sulfur content from footnote for Butane.

[c] Assumes controlled Low NO$_X$ burners for natural gas combustion from AP-42, Table 1.4-1.

[d] Additive factor for all POM materials listed in AP-42 Section 1.4, Table 1.4-3

[e] GHG emission factors are from 40 CFR 98 Subpart C Tables C-1 and C-2.

[f] Emission factors are from AP-42, 5th Edition, Section 1.5 (07/08) for propane. Sulfur content from Section 1.5 footnote for Butane.

[g] Global warming potential from 40 CFR 98 Subpart A Table A-1.

CO$_2$	1
CH$_4$	21
N$_2$O	310

Table C-7. Combustion Emissions

	Kiln 1 14-21-1410				Kiln 2 24-21-1410			
	Natural Gas Emissions		Propane Emissions		Natural Gas Emissions		Propane Emissions	
Pollutant	(lb/hr)	(ton/yr)	(lb/hr)	(ton/yr)	(lb/hr)	(ton/yr)	(lb/hr)	(ton/yr)
Criteria[a]								
VOC	0.27	1.19	0.54	2.36	0.27	1.19	0.54	2.36
CO	4.14	18.14	4.04	17.70	4.14	18.14	4.04	17.70
HAP/TAP Emissions								
Benzene	1.04E-04	4.53E-04			1.04E-04	4.53E-04		
Dichlorobenzene	5.92E-05	2.59E-04			5.92E-05	2.59E-04		
Formaldehyde	3.70E-03	1.62E-02			3.70E-03	1.62E-02		
n-Hexane	8.87E-02	3.89E-01			8.87E-02	3.89E-01		
Naphthalene	3.01E-05	1.32E-04			3.01E-05	1.32E-04		
Selenium	1.18E-06	5.18E-06			1.18E-06	5.18E-06		
Toluene	1.68E-04	7.34E-04			1.68E-04	7.34E-04		
POM	4.35E-06	1.90E-05			4.35E-06	1.90E-05		
Arsenic	9.86E-06	4.32E-05			9.86E-06	4.32E-05		
Beryllium	5.92E-07	2.59E-06			5.92E-07	2.59E-06		
Cadmium	5.42E-05	2.38E-04			5.42E-05	2.38E-04		
Chromium	6.90E-05	3.02E-04			6.90E-05	3.02E-04		
Cobalt	4.14E-06	1.81E-05			4.14E-06	1.81E-05		
Lead	2.47E-05	1.08E-04			2.47E-05	1.08E-04		
Manganese	1.87E-05	8.21E-05			1.87E-05	8.21E-05		
Mercury	1.28E-05	5.61E-05			1.28E-05	5.61E-05		
Nickel	1.04E-04	4.53E-04			1.04E-04	4.53E-04		
Greenhouse Gases								
CO_2	5,923.93	25,946.79	6,643.39	29,098.04	5,923.93	25,946.79	6,643.39	29,098.04
CH_4	0.11	0.49	0.32	1.42	0.11	0.49	0.32	1.42
N_2O	0.01	0.05	0.06	0.28	0.01	0.05	0.06	0.28
CO_2e	5,929.74	25,972.24	6,670.30	29,215.92	5,929.74	25,972.24	6,670.30	29,215.92

[a] PM emissions from combustion are included in the calculation of baghouse emissions using an outlet grain loading rate. Other kiln pollutants are calculated below.

Table C-8. Kiln Process Parameters

Process Emissions Input	
4.99	lb uncontrolled SO_2 /ton processed[a]
7.8	lb Uncontrolled NO_X /ton processed[b]
0.36%	Carbon Content (wt%)[c]
210	Fluoride concentration (ppmw)[d]
140	Chloride concentration (ppmw)[e]
0.217	Condensable PM Emissions Factor (lb/ton)[f]
2.2	CO Emissions Factor (lb/ton)[g]
90%	SO_2 Control Effectiveness
80%	NO_X Control Effectiveness
90%	HF/HCl Control Effectiveness

Notes:

[a] Email from Anna Koperczak, SSOE Group, to Will Chipley, Alberici Group, on May 31, 2011. Based on mass balance of material sulfur content.

[b] Engineering estimate from similar kiln designs. Includes 50% safety factor

[c] Maximum carbon content from core samples summarized in "pyramax cns 06-21-11.xls" provided by Mike Burgess, PyraMax, to Tom Muscenti, Trinity Consultants, via email on 6/21/11.

[d] Maximum fluoride concentration for Georgia clay from Table 2 of "Fluoride Content of Clay Minerals and Argillaceous Earth Materials," *Clay and Clay Minerals.*, Vol 25, pg 77, 1977. A 50% safety factor is applied.

[e] Concentration of chloride is based on ratio of controlled HF and HCl emission limits and percent reductions in Table 1 of 40 CFR 63 Subpart KKKK for new tunnel kilns with capacities greater than 10 tons per hour.

[Cl] = (controlled HCl/(1-percent reduction) / (controlled HF/(1-percent reduction) * [F]

[f] From AP-42 Section 11.6, Table 11-6.2 for portland cement. Sum of emission factors for clinker cooler with fabric filter and wet process kiln with fabric filter.

[g] Emission factor for gas fired rotary kiln AP-42, Section 11.17-6 (2/98).

Table C-9. Kiln Processing Emissions

		Condensable PM		SO_2		NO_2		CO		CO_2[a]		HCl[b]		HF[b]	
Emission Unit	Emission Unit ID	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy
Kiln 1	14-21-1410	5.07	22.19	11.64	51.00	36.30	158.99	51.36	224.94	616.28	2,699.31	0.67	2.94	1.03	4.52
Kiln 2	24-21-1410	5.07	22.19	11.64	51.00	36.30	158.99	51.36	224.94	616.28	2,699.31	0.67	2.94	1.03	4.52

[a] Calculation assumes all carbon in clay is converted to CO_2.

[b] Calculation assumes all fluoride/chloride in clay is converted to HF/HCl, respectively.

Table C-10. Pelletizer Combustion Emissions

	Pelletizer - Line 1 12-27-1100				Pelletizer - Line 2 22-27-1100			
	Natural Gas Emissions		Propane Emissions		Natural Gas Emissions		Propane Emissions	
Pollutant	**(lb/hr)**	**(ton/yr)**	**(lb/hr)**	**(ton/yr)**	**(lb/hr)**	**(ton/yr)**	**(lb/hr)**	**(ton/yr)**
Criteria[a]								
SO_2	0.05	0.20	0.01	0.06	0.05	0.20	0.01	0.06
NO_X[b]	2.25	9.86	2.25	9.86	2.25	9.86	2.25	9.86
VOC	0.41	1.81	0.82	3.59	0.41	1.81	0.82	3.59
CO[b]	13.73	60.12	13.73	60.12	13.73	60.12	13.73	60.12
HAP/TAP Emissions								
Benzene	1.58E-04	6.90E-04			1.58E-04	6.90E-04		
Dichlorobenzene	9.00E-05	3.94E-04			9.00E-05	3.94E-04		
Formaldehyde	5.63E-03	2.46E-02			5.63E-03	2.46E-02		
n-Hexane	1.35E-01	5.91E-01			1.35E-01	5.91E-01		
Naphthalene	4.58E-05	2.00E-04			4.58E-05	2.00E-04		
Selenium	1.80E-06	7.88E-06			1.80E-06	7.88E-06		
Toluene	2.55E-04	1.12E-03			2.55E-04	1.12E-03		
POM	6.62E-06	2.90E-05			6.62E-06	2.90E-05		
Arsenic	1.50E-05	6.57E-05			1.50E-05	6.57E-05		
Beryllium	9.00E-07	3.94E-06			9.00E-07	3.94E-06		
Cadmium	8.25E-05	3.61E-04			8.25E-05	3.61E-04		
Chromium	1.05E-04	4.60E-04			1.05E-04	4.60E-04		
Cobalt	6.30E-06	2.76E-05			6.30E-06	2.76E-05		
Lead	3.75E-05	1.64E-04			3.75E-05	1.64E-04		
Manganese	2.85E-05	1.25E-04			2.85E-05	1.25E-04		
Mercury	1.95E-05	8.54E-05			1.95E-05	8.54E-05		
Nickel	1.58E-04	6.90E-04			1.58E-04	6.90E-04		
Greenhouse Gases								
CO_2	9,012.06	39,472.81	10,106.57	44,266.79	9,012.06	39,472.81	10,106.57	44,266.79
CH_4	0.17	0.74	0.49	2.16	0.17	0.74	0.49	2.16
N_2O	0.02	0.07	0.10	0.43	0.02	0.07	0.10	0.43
CO_2e	9,020.90	39,511.52	10,147.52	44,446.13	9,020.90	39,511.52	10,147.52	44,446.13

[a] PM emissions from combustion are included in the calculation of baghouse emissions using an outlet grain loading rate.

[b] Assumes manufacturer's guaranteed emission factor from the Low NO_X burners for the following:

NO_X	0.030	lb/MMBtu
CO	0.183	lb/MMBtu

Table C-11. Boiler Combustion Emissions

	Boiler - Line 1				Boiler - Line 2			
	Natural Gas Emissions		Propane Emissions		Natural Gas Emissions		Propane Emissions	
Pollutant	(lb/hr)	(ton/yr)	(lb/hr)	(ton/yr)	(lb/hr)	(ton/yr)	(lb/hr)	(ton/yr)
Criteria								
PM	0.07	0.33	0.07	0.33	0.07	0.33	0.07	0.33
PM_{10}	0.07	0.33	0.07	0.33	0.07	0.33	0.07	0.33
$PM_{2.5}$	0.07	0.33	0.07	0.33	0.07	0.33	0.07	0.33
SO_2	0.01	0.03	0.00	0.01	0.01	0.03	0.00	0.01
NO_X	0.49	2.15	1.39	6.10	0.49	2.15	1.39	6.10
VOC	0.05	0.24	0.11	0.47	0.05	0.24	0.11	0.47
CO	0.82	3.61	0.80	3.52	0.82	3.61	0.80	3.52
HAP/TAP Emissions								
Benzene	2.06E-05	9.01E-05			2.06E-05	9.01E-05		
Dichlorobenzene	1.18E-05	5.15E-05			1.18E-05	5.15E-05		
Formaldehyde	7.35E-04	3.22E-03			7.35E-04	3.22E-03		
n-Hexane	1.76E-02	7.73E-02			1.76E-02	7.73E-02		
Naphthalene	5.98E-06	2.62E-05			5.98E-06	2.62E-05		
Selenium	2.35E-07	1.03E-06			2.35E-07	1.03E-06		
Toluene	3.33E-05	1.46E-04			3.33E-05	1.46E-04		
POM	8.64E-07	3.79E-06			8.64E-07	3.79E-06		
Arsenic	1.96E-06	8.58E-06			1.96E-06	8.58E-06		
Beryllium	1.18E-07	5.15E-07			1.18E-07	5.15E-07		
Cadmium	1.08E-05	4.72E-05			1.08E-05	4.72E-05		
Chromium	1.37E-05	6.01E-05			1.37E-05	6.01E-05		
Cobalt	8.23E-07	3.61E-06			8.23E-07	3.61E-06		
Lead	4.90E-06	2.15E-05			4.90E-06	2.15E-05		
Manganese	3.72E-06	1.63E-05			3.72E-06	1.63E-05		
Mercury	2.55E-06	1.12E-05			2.55E-06	1.12E-05		
Nickel	2.06E-05	9.01E-05			2.06E-05	9.01E-05		
Greenhouse Gases								
CO_2	1,177.58	5,157.78	1,320.59	5,784.19	1,177.58	5,157.78	1,320.59	5,784.19
CH_4	0.02	0.10	0.06	0.28	0.02	0.10	0.06	0.28
N_2O	0.00	0.01	0.01	0.06	0.00	0.01	0.01	0.06
CO_2e	1,178.73	5,162.84	1,325.94	5,807.63	1,178.73	5,162.84	1,325.94	5,807.63

Table C-12. Additive Process Inputs

Process Emissions Input	
0.50%	(w/w) methanol in the Additive Material[a,b]
0.50%	(w/w) methyl acetate in the Additive Material[a,b]
0.638	mol fraction methanol in the Additive Material[c]
0.264	mol fraction methyl acetate in the Additive Material[c]
10.73	R (ft^3·psi/°R·lb-mol)
74.09	MW Methyl Acetate (lbm/lbmol)
32.05	MW Methanol (lbm/lbmol)
96	Temperature (F)[c]
4.068	vapor pressure of methanol (psia)
6.356	vapor pressure of methyl acetate (psia)
1	number of times silo filled per day[b]
2,161	Silo vapor displaced during fill[c]
365	number of fills per year
30.15	Methanol emitted each time silo is refilled (lb) - assumes fill in one hour
45.06	Methyl acetate emitted each time silo is refilled (lb) - assumes fill in one hour
1,096	Binder Usage (lb/hr)[d]

[a] Information provided by Anna Koperczak, SSOE, to Trinity Consultants, on 6/20/11.

[b] Data sheet lists 1% volatile organics, no distribution given for methanol and methyl acetate.

[c] Information provided in "Silo Volatiles.xls" by Anna Koperczak, SSOE, to Trinity Consultants, on 6/29/11.

[d] Process rates from "Preliminary PyraMax Emission Units 6-2-11.xls" downloaded from Sharepoint site on 6/6/11. Throughputs are based on the +20% design values.

Table C-13. Antoine's Coefficients

Vapor Pressure Constants			
A	B	C	
14.57667313	-6515.55467	398.591	Methanol
12.71269875	-5214.47257	384.01	Methyl Acetate

Table C-14. pH Process Inputs

Process Emissions Input	
26%	(w/w) ammonia in the pH adjuster
472	Amount of pH adjuster added (lb/hr)

Table C-15. Additive Emissions Summary

		Methanol			Methyl Acetate			VOC		Ammonia[a]	
Equipment	**ID No.**	**(lb/hr)**	**(lb/day)**	**(ton/yr)**	**(lb/hr)**	**(lb/day)**	**(ton/yr)**	**(lb/hr)**	**(ton/yr)**	**(lb/hr)**	**(ton/yr)**
Additive Silo	Line 1/2	30.15	30.15	5.50	45.06	45.06	8.22	75.21	13.73	--	--
Pelletizer	12-27-1100	5.48	131.52	24.00	5.48	131.52	24.00	10.96	48.00	122.71	537.45
	22-27-1100	5.48	131.52	24.00	5.48	131.52	24.00	10.96	48.00	122.71	537.45

[a] Even though only a portion of the ammonia in the pH adjuster is present as NH3, PyraMax conservatively assume it is all emitted as NH3.

Table C-16. Engine Input Parameters

Process Parameter		Units
Run Time[a]	100	hours/year
1kW =	1.34	hp
Engine Rating	670	hp
Engine Rating	500	kW
Engine Usage	67,000	hp-hr/year
Engine Usage	50,000	kW-hr/yr
Engines per Gen Set	2	
BSFC[b]	7,000	Btu/hp-hr

[a] Per 63.6640(f)(1)(ii), maintenance and readiness checks are limited to 100 hours for emergency engines.

[b] AP-42, Fifth Edition, Section 3.3, Gasoline & Diesel Industrial Engines (10/96), Table 3.3-1 footnote c.

Table C-17. Engine Emissions Summary

			GEN-1 Emissions			GEN-2 Emissions		
Pollutant	Factor[a]	Units	lbs/hr	lbs/yr	tons/yr	lbs/hr	lbs/yr	tons/yr
PM_{10}[b]	0.20	g/kW-hr	0.44	44.09	0.02	0.44	44.09	0.02
$PM_{2.5}$[b]	0.20	g/kW-hr	0.44	44.09	0.02	0.44	44.09	0.02
SO_x	2.05E-03	lb/hp-hr	2.75	274.70	0.14	2.75	274.70	0.14
NO_X[b]	4.0	g/kW-hr	8.82	881.85	0.44	8.82	881.85	0.44
NMHC[b]	4.0	g/kW-hr	8.82	881.85	0.44	8.82	881.85	0.44
CO[b]	3.5	g/kW-hr	7.72	771.62	0.39	7.72	771.62	0.39
CO_2	163.05	lb/MMBtu	1,529.43	152,943	76.47	1,529.43	152,943	76.47
CH_4	6.61E-03	lb/MMBtu	6.20E-02	6.20E+00	3.10E-03	6.20E-02	6.20E+00	3.10E-03
N_2O	1.32E-03	lb/MMBtu	1.24E-02	1.24E+00	6.20E-04	1.24E-02	1.24E+00	6.20E-04
CO_2e			1,534.58	153,458	76.73	1,534.58	153,458	76.73
Benzene	9.33E-04	lb/MMBtu	8.75E-03	8.75E-01	4.38E-04	8.75E-03	8.75E-01	4.38E-04
Toluene	4.09E-04	lb/MMBtu	3.84E-03	3.84E-01	1.92E-04	3.84E-03	3.84E-01	1.92E-04
Xylene	2.85E-04	lb/MMBtu	2.67E-03	2.67E-01	1.34E-04	2.67E-03	2.67E-01	1.34E-04
Propylene	2.58E-03	lb/MMBtu	2.42E-02	2.42E+00	1.21E-03	2.42E-02	2.42E+00	1.21E-03
1,3 Butadiene	3.91E-05	lb/MMBtu	3.67E-04	3.67E-02	1.83E-05	3.67E-04	3.67E-02	1.83E-05
Formaldehyde	1.18E-03	lb/MMBtu	1.11E-02	1.11E+00	5.53E-04	1.11E-02	1.11E+00	5.53E-04
Acetaldehyde	7.67E-04	lb/MMBtu	7.19E-03	7.19E-01	3.60E-04	7.19E-03	7.19E-01	3.60E-04
Acrolein	9.25E-05	lb/MMBtu	8.68E-04	8.68E-02	4.34E-05	8.68E-04	8.68E-02	4.34E-05
Benzo(a)pyrene	1.88E-07	lb/MMBtu	1.76E-06	1.76E-04	8.82E-08	1.76E-06	1.76E-04	8.82E-08
PAH	1.68E-04	lb/MMBtu	1.58E-03	1.58E-01	7.88E-05	1.58E-03	1.58E-01	7.88E-05

[a] Emission factors taken from AP-42, Fifth Edition, Section 3.3, Gasoline & Diesel Industrial Engines (10/96), Tables 3.3-1 and 3.3-2. All PM assumed to be less than 1 micron per footnote b of Table 3.3-1.

[b] Emission factors taken from NSPS Subpart IIII. Emission limit for NO_X and NMHC is combined. Emissions are calculated assuming the combined emission factor is for each pollutant.

Table C-18. Storage Tank Emissions

Tank Description	VOC Emissions lb/hr	VOC Emissions tpy
7,000 gal diesel storage tank	6.70E-04	2.94E-03
1,000 gal diesel storage tank	8.90E-05	3.90E-04
2,375 Diesel generator storage tank - Line 1	2.27E-04	9.95E-04
2,375 Diesel generator storage tank - Line 2	2.27E-04	9.95E-04
Total	1.21E-03	5.32E-03

TANKS 4.0.9d
Emissions Report - Summary Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	0001
City:	
State:	
Company:	
Type of Tank:	Horizontal Tank
Description:	Generator diesel tank

Tank Dimensions

Shell Length (ft):	10.00
Diameter (ft):	4.00
Volume (gallons):	1,000.00
Turnovers:	12.00
Net Throughput(gal/yr):	12,000.00
Is Tank Heated (y/n):	N
Is Tank Underground (y/n):	N

Paint Characteristics

Shell Color/Shade:	Gray/Light
Shell Condition	Good

Breather Vent Settings

Vacuum Settings (psig):	-0.03
Pressure Settings (psig)	0.03

Meterological Data used in Emissions Calculations: Augusta, Georgia (Avg Atmospheric Pressure = 14.69 psia)

TANKS 4.0.9d
Emissions Report - Summary Format
Liquid Contents of Storage Tank

0001 - Horizontal Tank

		Daily Liquid Surf. Temperature (deg F)			Liquid Bulk Temp	Vapor Pressure (psia)			Vapor Mol.	Liquid Mass	Vapor Mass		Basis for Vapor Pressure
Mixture/Component	Month	Avg.	Min.	Max.	(deg F)	Avg.	Min.	Max.	Weight.	Fract.	Fract.	Mol. Weight	Calculations
Distillate fuel oil No. 2	All	70.61	60.67	80.54	65.42	0.0092	0.0067	0.0122	130.0000			188.00	Option 1: VP70 = .009 VP80 = .012

TANKS 4.0.9d
Emissions Report - Summary Format
Individual Tank Emission Totals

Emissions Report for: Annual

0001 - Horizontal Tank

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Distillate fuel oil No. 2	0.34	0.44	0.78

TANKS 4.0.9d
Emissions Report - Summary Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	0003
City:	
State:	
Company:	
Type of Tank:	Horizontal Tank
Description:	diesel tank

Tank Dimensions

Shell Length (ft):	20.00
Diameter (ft):	8.00
Volume (gallons):	7,000.00
Turnovers:	12.00
Net Throughput(gal/yr):	84,000.00
Is Tank Heated (y/n):	N
Is Tank Underground (y/n):	N

Paint Characteristics

Shell Color/Shade:	Gray/Light
Shell Condition	Good

Breather Vent Settings

Vacuum Settings (psig):	-0.03
Pressure Settings (psig)	0.03

Meterological Data used in Emissions Calculations: Augusta, Georgia (Avg Atmospheric Pressure = 14.69 psia)

TANKS 4.0.9d
Emissions Report - Summary Format
Liquid Contents of Storage Tank

0003 - Horizontal Tank

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Distillate fuel oil No. 2	All	70.61	60.67	80.54	65.42	0.0092	0.0067	0.0122	130.0000			188.00	Option 1: VP70 = .009 VP80 = .012

TANKS 4.0.9d
Emissions Report - Summary Format
Individual Tank Emission Totals

Emissions Report for: Annual

0003 - Horizontal Tank

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Distillate fuel oil No. 2	2.39	3.48	5.87

TANKS 4.0.9d
Emissions Report - Summary Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	0001
City:	
State:	
Company:	
Type of Tank:	Horizontal Tank
Description:	Generator diesel tank

Tank Dimensions

Shell Length (ft):	12.00
Diameter (ft):	6.00
Volume (gallons):	2,375.00
Turnovers:	12.00
Net Throughput(gal/yr):	28,500.00
Is Tank Heated (y/n):	N
Is Tank Underground (y/n):	N

Paint Characteristics

Shell Color/Shade:	Gray/Light
Shell Condition	Good

Breather Vent Settings

Vacuum Settings (psig):	-0.03
Pressure Settings (psig)	0.03

Meterological Data used in Emissions Calculations: Augusta, Georgia (Avg Atmospheric Pressure = 14.69 psia)

TANKS 4.0.9d
Emissions Report - Summary Format
Liquid Contents of Storage Tank

0001 - Horizontal Tank

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Distillate fuel oil No. 2	All	70.61	60.67	80.54	65.42	0.0092	0.0067	0.0122	130.0000			188.00	Option 1: VP70 = .009 VP80 = .012

TANKS 4.0.9d
Emissions Report - Summary Format
Individual Tank Emission Totals

Emissions Report for: Annual

0001 - Horizontal Tank

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Distillate fuel oil No. 2	0.81	1.18	1.99

APPENDIX D – BACT SUPPORTING INFORMATION

Table D-1. NO$_X$ Best Available Control Technology RBLC Search - Kilns/Calciners

ID	State	Company/Facility	Database	Process Type	Throughput	Throughput Units	Primary Fuel	Permit Type	Permit Date	Emission Limit	Limit Unit	Emission Limit (lb/hr)	Avg. Period	Control Type
TX-0253	TX	AKZO NOBEL CHEMICALS, INC.	RBLC	CALCINER	40	MMBTU/H		D	06/20/2000	0.066	LB/MMBTU	0.07		PROCESS EXHAUST GASES ARE ROUTED TO SCR
CA-0653	CA	A & M PRODUCTS	RBLC	ROTARY AGGREGATE DRYER	15	TON AGGREGATE/HR	LPG		04/13/1995	44.5	LBM/DAY	1.85		FUEL SPEC: LPG FIRING
FL-0271	FL	Branford Cement Plant	RBLC	Coal Fired Kiln with in line Raw Mil					3/6/2011	1.95	lb/hr	1.95	30 DAY	SNCR with Baghouse / PSD BACT
FL-0268	FL	Brookville Cement Plan	RBLC	Coal Fired Clinker Kiln					Dec-04	1.95	lb/hr	1.95	30-DAYS ROLLING	SNCR / PSD BACT
N/A	GA	Carbo Cermamics, McIntyre Plan	Title V	Indirect-fired Rotary Calcine			NG, Propane		12/16/2009	5	lb/hr	5		Good Combustion Techniques/Low NOX burners
N/A	GA	Carbo Cermamics, McIntyre Plan	Title V	Rotary Dryer			NG, Propane		12/16/2009	5.32	lb/hr	5.32		Good Combustion Techniques/Low NOX burners
N/A	GA	Carbo Cermamics, McIntyre Plan	Title V	Rotary Dryer			NG, Propane		12/16/2009	5.32	lb/hr	5.32		Good Combustion Techniques/Low NOX burners
OR-0042	OR	EAGLE- PICHER VALE, OREGON PLANT	RBLC	DRYER 1/CALCINER 1	2990400	LB/WK	NATURAL GAS	A	05/23/2003	6.6	LB/H	6.60	3-hr average	GOOD COMBUSTION CONTROL
OR-0042	OR	EAGLE- PICHER VALE, OREGON PLANT	RBLC	DRYER 2/CALCINER 2	3124800	LB/WK	NATURAL GAS	A	05/23/2003	7.1	LB/H	7.10	3-hour average	GOOD COMBUSTION PRACTICES
WY-0055	WY	Wold Trona	RBLC	N.G. fired Trona Calciner			Natural Gas		4/27/2000	0.038	lb/MMBtu	8.10		Low NOx Burner / PSD BACT
AR-0025	AR	General Shale Products Corp	RBLC	N.G. fired Aggregate Kiln					5/6/1999	8.5	lb/hr	8.50		Good Combustion / PSD BACT
TX-0271	TX	CHEMICAL LIME LTD.-- LIME PLANT	RBLC	KILN	25	T/H	NATURAL GAS	D	08/05/1997	9.1	LB/H	9.10		
GA-0074	GA	DRY BRANCH KAOLIN CO.	RBLC	CALCINER NO. 4			FUEL OIL	D	11/06/1995	40	TONS/12 CONSEC. MOS.	9.13		LIMITED FUEL CONSUMPTION
AR-0082	AR	ARKANSAS LIME COMPANY	RBLC	LIME KILN, SN-30Q	45254	T/YR	COAL/COKE AND NATURAL GAS	A	08/30/2005	3.5	LB/T	18.08	LB/TON OF LIME, 30 DAY ROLLING AVERAGE	
WY-0038	WY	WOLD TRONA CO.	RBLC	CALCINER & CALCINER BOILER, (2)	213.15	T/H		D	05/02/1995	0.048	LB/MMBTU	18.14		MONOWALL FURNACE CONSTRUCTION LOW NOX BURNERS WITH FUEL STAGING, 15% EXCESS AIR FLUE GAS RECIRCULATION(FGRS 15%) ON CALCINER BOILER
FL-0224	FL	FLORIDA ROCK INDUSTRIES, INC.	RBLC	KILN, PORTLAND CEMENT	14	T/H	COAL	A	12/23/1996	2.45	LB/T	34.30	clinker, 30 day rolling avg	PROCESS CONTROL AND SECONDARY COMBUSTION OF FUEL.
N/A	GA	Carbo Cermamics, McIntyre Plan	Title V	Raw Materials Calciner			NG, Propane		12/16/2009	40	lb/hr	40		Good Combustion Techniques/Low NOX burners
NC-0077	NC	CAROLINA STALITE COMPANY - GOLD HILL	RBLC	ROTARY EXPANDING KILN	23	T/H	COAL	D	12/20/2001	43.7	LB/H	43.70		GOOD COMBUSTION TECHNIQUES
	LA	Big River Industries, Inc	RBLC	Direct coal-fired rotary kilns, Nos. 1-4	41	MMBtu/hr	Coal		Jun 06	57.22	lb/hr	57.22		Good Combustion Practices
LA-0209	LA	GRAVELITE DIVISION	RBLC	ROTARY KILNS, NOS. 1-4	22	T/H	COAL	C	06/28/2006	57.22	LB/H	57.22	HOURLY MAXIMUM	GOOD COMBUSTION AND MAINTENANCE PRACTICES
WI-0090	WI	WESTERN LIME CORPORATION	RBLC	LIME KILN #2, P38, S18	123.3	MMBTU/H	COAL	D	07/23/1996	60	LB/H	60.00		BACT FOR NITROGEN OXIDES HAS BEEN DETERMINED TO BE GOOD COMBUSTION PRACTICES WITH AN EMISSION LIMIT OF 60.0 POUNDS PER HOUR, AS MEASURED BY USEPA METHOD 7
TX-0536	TX	SEADRIFT COKE	RBLC	CALCINERS PETROLEUM	1340	T/D	NATURAL GAS	A	04/20/2009	415	T/YR	63.48		COMPANY COSTED OUT OF CONTROLS FOR NO2 CONTROL
MT-0012	MT	CONTINENTAL LIME INC.	RBLC	KILN-LIME, TWO	0				11/19/1997	77.5	LB/H EACH	77.50		BAGHOUSES, 75000 ACFM AT 470F WITH APPROX. 17000 SQ.FT AND AN AIR-TO-CLOTH RATIO OF 4:4:1.
MT-0006	MT	CONTINENTAL LIME-INDIAN CREEK OP'N	RBLC	LIME KILNS	500	TPD CAO EACH			03/20/1996	77.5	LBS/HR	77.50		
N/A	GA	Carbo Cermamics, McIntyre Plan	Title V	Kiln (Rotary Calciner			NG, Propane		12/16/2009	82	lb/hr	82		Good Combustion Techniques/Low NOX burners
N/A	GA	Carbo Cermamics, McIntyre Plan	Title V	Kiln (Rotary Calciner			NG, Propane		12/16/2009	82	lb/hr	82		Good Combustion Techniques/Low NOX burners
AR-0028	AR	ARKANSAS LIME COMPANY	RBLC	KILN, LIME	625	T/D LIME	COAL/COKE	A	09/14/1999	91.2	LB/H	91.20		PROPER DESIGN AND OPERATION OF LIME KILN
WI-0233	WI	CLM - SUPERIOR	RBLC	LIME KILN (P50)	650	T/D	COAL / PET COKE	A	08/16/2006	98.8	LB/H	98.80	3 HOUR AVG.	USE OF A PREHEATER TYPE ROTARY KILN AND GOOD COMBUSTION PRACTICES / OPTIMIZATION WHICH MINIMIZE NITROGEN OXIDE EMISSIONS (WHILE MAINTAINING COMPLIANCE WITH CO LIMIT)
WI-0250	WI	GRAYMONT (WI) LLC	RBLC	P50 (S50). PREHEATER EQUIPPED, ROTARY LIME KILN	54	T/H STONE	COAL	A	02/06/2009	1.83	LB/T	98.80	24 HOUR AVG.	GOOD COMBUSTION CONTROL, OPTIMIZATION
MT-0020	MT	GRAYMONT WESTERN US, INC.	RBLC	LIME KILN, ROTARY	187500	T/YR	COAL	D	11/01/2000	100	LB/H	100.00		GOOD COMBUSTION PRACTICES
TX-0360	TX	TEXAS LIME	RBLC	LIME KILN NO 4, 4-WS-1			COAL	D	08/02/1999	104.3	LB/H	104.30		NONE INDICATED
TX-0452	TX	AUSTIN WHITE LIME COMPANY MCNEIL PLANT & QUARRY	RBLC	KILN NO 1 AND 2					11/19/2003	106.1	LB/H	106.10		THE KILNS ARE CONTROLLED WITH EITHER A CYCLONE/WET SCRUBBER COMBO
SC-0053	SC	PALMETTO LIME, LLC	RBLC	VERTICAL SHAFT KILNS (LIME MANUFACTURING)	1200	T/D		A	12/12/1997	2.2	LB/T	110.00		
TX-0452	TX	AUSTIN WHITE LIME COMPANY MCNEIL PLANT & QUARRY	RBLC	KILN NO 3					11/19/2003	118.3	LB/H	118.30		THE KILNS ARE CONTROLLED WITH EITHER A CYCLONE/BAGHOUSE COMBO
N/A	GA	Carbo Cermamics, Toomsboro Plan	Title V	Direct-fired Calciner/Kilns (4			NG, Propane		12/16/2009	121	lb/hr	121	3-hours	Good Combustion Techniques/Low NOX burners
MI-0383	MI	WESTERN LIME CORPORATION	RBLC	LIME KILN	186.3	MMBTU/H	COAL AND PETROLEUM COKE MIXTURE	A	01/30/2004	132.6	LB/H	132.60		LOW-NOX BURNERS AND LIMIT EXCESS AIR
OH-0321	OH	MARTIN MARIETTA MATERIALS	RBLC	ROTARY LIME KILN	18000	LB/H	COAL, COKE, NATURAL GAS	B	11/13/2008	673.43	T/YR	153.75	PER ROLLING 12-MONTH PERIOD	
TX-0360	TX	TEXAS LIME	RBLC	LIME KILN NO 6, 6-WS-1	850	T/D CAO	COAL	D	08/02/1999	157.1	LB/H	157.10		NONE INDICATED
PA-0241	PA	GRAYMONT BELLEFONTE PLANT	RBLC	# 7 LIME KILN	1050	T/D	COAL/PETROLEUM COKE	D	07/09/2004	709	T/YR	161.87	12 MONTH ROLLING AVG	
UT-0054	UT	CONTINENTAL LIME INC. - CRICKET MTN. LIME PLANT	RBLC	KILN, #4	1200	T/D, LIME	NATURAL GAS		01/10/1996	200	LB/H	200.00		
AZ-0051	AZ	DRAKE	RBLC	KILN	83.33	T/H	COAL	A	04/12/2006	2.45	LB/T	204.16	30-DAY AVERAGE (FOR FIRST 30 DAYS)	SNCR
WY-0044	WY	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	RBLC	KILN, COAL FIRED	45.3	T/H COAL			03/06/1995	208.8	LB/H (30DAY ROLLING)	208.80		COMBUSTION UNIT DESIGN (WELL DESIGNED PROCESS BURNER OPERATED IN DESIGN RANGE)
AL-0234	AL	LIVITE DIVISION	RBLC	KILN NO.3 - COAL FIRED ROTARY KILN	83	T/H	COAL	C	07/24/2007	220	LB/H	220.00		GOOD COMBUSTION
FL-0110	FL	FL CRUSHED STONE	RBLC	PORTLAND CEMENT MANUFACTURING, KILN	83	T/H	COAL	D	11/17/1995	2.8	LB/T	232.40	CLINKER, 24 H	COMBUSTION PRACTICES
IL-0084	IL	VULCAN MATERIALS	RBLC	LIME KILN	1296	T/D		D	10/28/2002	4.5	LB/T	243.00	LB/T STONE FEED	BEST COMBUSTION PRACTICES
FL-0268	FL	BROOKSVILLE CEMENT PLANT (FCS)	RBLC	125 TPH CLINKER KILN AND ASSOCIATED EQUIPMENT			COAL	B	12/20/2004	1.95	LB/TON CLINKER	243.75	30 DAY	SNCR
FL-0267	FL	THOMPSON S. BAKER- CEMENT PLANT (FRI)	RBLC	IN LINE KILN/RAW MILL WITH ESP AND SNCR			COAL	B	11/05/2004	1.95	LB/TON CLINKER	243.75	30 DAY	SNCR
FL-0271	FL	BRANFORD CEMENT PLANT (SUWANNE)	RBLC	KILN W/IN LINE RAW MILL W/ SNCR AND BAGHOUSE	127	T/H clinker	COAL	B	03/30/2006	1.95	LB/TON CLINKER	247.65	CEMS 30 DAYS ROLLING AVERAGE	SNCR
UT-0062	UT	HOLNAM, DEVIL'S SLIDE PLANT	RBLC	KILN			COAL	D	05/13/1996	251	LB/H	251.00		LOW NOX BURNER
CO-0043	CO	RIO GRANDE PORTLAND CEMENT CORP.	RBLC	PREHEATER/PRECALCINER, KILN	950000	T/YR		A	09/25/2000	2.32	LB/T	251.60		MULTI-STAGE COMBUSTION AND RECIRCULATION. EMISSION LIMIT IN LB/T OF CLINKER. LB/T LIMIT IS 12-MO ROLLING AVG
FL-0173	FL	SOUTHDOWN, INC.	RBLC	PORTLAND CEMENT, KILN 2	165	T/H		D	06/27/1997	1.72	LB/T	283.80	lb/t kiln feed	GOOD COMBUSTION PRACTICES AND BURNER DESIGN WITH PRIMARY COMBUSTION AIR CONTROL.
FL-0173	FL	SOUTHDOWN, INC.	RBLC	PORTLAND CEMENT, KILN 1	165	T/H		D	06/27/1997	1.8	LB/T	297.00	lb/t kiln feed	GOOD COMBUSTION PRACTICES AND BURNER DESIGN WITH PRIMARY COMBUSTION AIR CONTROL.
NV-0032	NV	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.	RBLC	CEMENT KILN/CLINKER COOLER FACILITY	0				10/24/1995	3.1	LB/TON CLINKER PROD.	353.42		SELECTIVE NON-CATALYTIC REDUCTION (SNCR) UREA INJECTION SYSTEM AT PREHEATER
UT-0059	UT	ASH GROVE CEMENT COMPANY	RBLC	KILN	170	T/H	COAL	D	10/24/1996	400	LB/H	400.00		LOW NOX BURNER. PRIMARY EMISSION LIMIT: 400 LB/H AT 90% OF MAX PRODUCTION CAPACITY. NOTE: TITLE V PERMIT DOES NOT INCLUDE ‘‘AT 90% OF MAXIMUM PRODUCTION‘&lsquo
WA-0307	WA	PORTLAND CEMENT CLINKERING PLANT	RBLC	KILN EXHAUST STACK				D	10/05/2001	650	PPM @ 10% O2	421.46	24-H AV	NONE INDICATED.
IA-0070	IA	LEHIGH CEMENT COMPANY - MASON CITY PLANT	RBLC	KILN/CALCINER/PREHEATER	150	T/H	COAL	D	12/11/2003	2.85	LB/T	427.50	LB/T OF CLINKER	SNCR, LOW NOX BURNERS, COMBUSTION CONTROLS, AND PROPER KILN DESIGN.
MO-0048	MO	LAFARGE CORPORATION	RBLC	RAW MILL, PREHEATER/PRECALCINER KINL(EP 78)	1584071	TONS		A	08/20/1997	1894.8	TON/YR	432.60		GOOD COMBUSTION PRACTICES
GA-0134	GA	HOUSTON AMERICAN CEMENT PLANT	RBLC	MAIN KILN STACK ST35	229	T/H OF DRY FEED	COAL	A	06/19/2007	1.95	LB/T CLINKER	446.55	30 DAY ROLLING AVG	STAGED AND CONTROLLED COMBUSITON (SCC), SNCR, LOW NOx BURNER AND INDIRECT FIRING.
TX-0282	TX	CAPITOL CEMENT DIVISION	RBLC	DRY KILN EXHAUST BAGHOUSE (KS-1A)	730000	T/YR CLINKER	SEE PLANT INFO PAGE	D	09/16/1998	450	LB/H	450.00		NONE INDICATED.
TX-0282	TX	CAPITOL CEMENT DIVISION	RBLC	WET KILN EXHAUST BAGHOUSE (KS-1B)	378650	T/YR CLINKER	SEE PLANT INFO PAGE	D	09/16/1998	450	LB/H	450.00		NONE INDICATED
IN-0112	IN	LONE STAR INDUSTRIES, INC.	RBLC	CEMENT KILN, WET PROCESS, COAL	75	T/H	COAL	D	09/18/1998	471	LB/H	471.00		LOW NOX BURNERS AND GOOD COMBUSTION
FL-0139	FL	SUWANNEE AMERICAN CEMENT COMPANY, INC.	RBLC	IN LINE KILN & RAW MILL	178	T/H	NATURAL GAS	A	06/01/2000	2.9	LB/T	516.20	CLINKER	MULTI-STAGE COMBUSTION W/SEPARATE LINE CALCINER COMBUSTION CHAMBER.
SD-0003	SD	GCC DACOTAH	RBLC	ROTARY KILN #6	2250	T/D	CLINKER	D	04/10/2003	2267	T/YR	517.58		PREHEATER/PRECALCINATOR SYSTEM
GA-0136	GA	CEMEX SOUTHEAST, LLC	RBLC	MAIN KILN STACK K218	270	T/H OF DRY FEED	COAL	B	01/27/2010	1.95	LB/T CLINKER	526.50	30-DAY ROLLING AVG. BASED ON NOX CEMS	STAGED & CONTROLLED COMBUSTION (SCC), SNCR, LOW NOx BURNER AND INDIRECT FIRING.
KS-0022	KS	MONARCH CEMENT COMPANY	RBLC	2 PRECALCINERS (EACH)	120	MMBTU/H	NATURAL GAS	D	01/27/2000	200	T/MO	542.51		NATURAL GAS
IL-0057	IL	ILLINOIS CEMENT COMPANY	RBLC	KILN, CEMENT, PREHEATER-PRECALCINER	3000	TON/D CEMENT CLINKER		D	06/12/1998	4.5	LB/T CLINKER	562.50		CONVERSION TO PRECALCINER KILN
IA-0052	IA	LAFARGE CORPORATION	RBLC	CEMENT MANUFACTURING, PREHEATER/PRECALCINER KILN	3488	T/D	COAL	D	07/01/2002	2546	T/YR	581.28		GOOD COMBUSTION PRACTICES
MI-0287	MI	HOLNAM, INC.	RBLC	CEMENT KILNS, WET PROCESS (2)	100	T/H FEED	COAL	D	03/20/2000	6	LB/T	600.00		CURRENT EXISTING LIMIT DOES NOT REFLECT POTENTIAL 30% REMOVAL IN SLURRY-SCRUBBER. SOME GENERATION OF NO2 BY NATURAL GAS COMBUSTION IN RTOS.
TX-0466	TX	TEXAS LEHIGH CEMENT	RBLC	KILN EXHAUST (4)					02/03/2003	600	LB/H	600.00		BAGHOUSES
TX-0355	TX	PORTLAND CEMENT MANUFACTURING PLANT	RBLC	GRINDING/ PREHEATING/ KILN, K-19				D	06/29/2001	660	LB/H	660.00		NONE INDICATED
CO-0047	CO	HOLNAM, FLORENCE	RBLC	KILN/PREHEATER/BYPASS & CLINKER COOLER EXHAUST			COAL	D	07/29/1999	2922.71	T/YR	667.29		LOW NOX COMBUSTION SYSTEM
AL-0203	AL	HOLCIM (US), INC.	RBLC	KILN SYSTEM (CALCINING KILN, PREHTR W/PRECALCINER)	390	T/H	COAL	D	02/04/2003	2998	T/YR	684.47		
MI-0354	MI	HOLNAM, INC	RBLC	CEMENT KILNS, WET PROCESS, (2)	100	T/H	COAL	A	06/23/1998	3377	T/YR	771.00	combined	
CO-0048	CO	HOLNAM, LAPORTE CO.	RBLC	CALCINER/ KILN	584000	T/YR	COAL	D	09/22/1998	900	LB/H	900.00		SPECIAL PROCESS: DESIGN OF BURNER/KILN TO CONTROL ALKALI FROM LIMESTONE INCREASES NOX EMISSIONS.
TX-0282	TX	CAPITOL CEMENT DIVISION	RBLC	DRY/WET KILN & ALKALI BYPASS BAGHOUSE STACK (KS-1)		SEE NOTES	SEE PLANT INFORMATIO	D	09/16/1998	950	LB/H	950.00		NONE INDICATED
	VA	Roanoke Cement	RBLC	Coal fired lime kiln						982	lb/hr	982.00		Good Combustion Practices and CEMs / PSD BACT
IN-0081	IN	LONE STAR INDUSTRIES, INC.	RBLC	CEMENT MANUFACTURING, KILN OPERATION	360	T/H	COAL	D	04/16/1999	4428	T/YR	1010.96		LOW NOX CALCINER, GOOD COMBUSTION PRACTICES
TX-0279	TX	NORTH TEXAS CEMENT COMPANY	RBLC	MAIN KILN/SCRUBBER STACK	3100	T/D CLINKER	COAL	A	03/04/1999	1085	LB/H	1085.00		SEPARATE LINE DOWNDRAFT LOW-NOX CALCINER AND LOW-NOX IN-LINE CALCINER.
MD-0027	MD	LEHIGH PORTLAND CEMENT COMPANY	RBLC	CEMENT MANUFACTURING, PREHEATER/PRECALCINER KILN	2214000	T/YR	COAL	D	06/08/2000	4871	T/YR	1112.10		A 5-STAGE PREHEATER/PRECALCINER PYROPROCESSING PLANT IS SELECTED FOR NOX EMISSION ABATEMENT. ANY ADD-ON NOX EMISSIONS CONTROL HAS BEEN DETERMINED TO BE EITHER TECHNICALLY OR ENVI. INFEASIBLE
OH-0270	OH	CARMEUSE LIME - MAPLE GROVE FACILITY	RBLC	ROTARY KILN (2)	650	T/D	COAL, COKE, NG	A	10/14/2003	1234.9	LB/H	1234.90	FOR EACH KILN	
MO-0059	MO	CONTINENTAL CEMENT COMPANY, LLC	RBLC	ROTARY KILN	183	T/H	COAL	A	09/24/2002	8	LB/T	1464.00	lb/t clinker, 30-day rolling avg	SELECTIVE NON-CATALYTIC REDUCTION, LOW NOX BURNERS, TOP AIR DUCT.
FL-0297	FL	NORTH BROOKSVILLE CEMENT PLANT	RBLC	KILN NO. 3 WITH PREHEATER, CALCINER, IN-LINE RAW MILL AND AIR HEATER	550	MMBTU/H	COAL	B	06/27/2007	1.5	LB/T CLINKER		30-DAYS ROLLING	THE SELECTIVE NON-CATALYTIC REDUCTION (SNCR) PROCESS, THE SELECTIVE CATALYTIC REDUCTION (SCR) PROCESS OR ANY COMBINATION THEREOF
WY-0036	WY	OCI, Wyoming L.P.-OCI Soda Ash Plan	RBLC	N.G. fired Trona Calciner					5/27/1997	0.05	lb/MMBtu			Low NOx Burner / PSD BACT
WY-0036	WY	OCI, Wyoming L.P.-OCI Soda Ash Plan	RBLC	N.G. fired Soda Ash Rotary Dryer					5/27/1997	0.15	lb/MMBtu			Low NOx Burner / PSD BACT
WY-0036	WY	OCI, Wyoming L.P.-OCI Soda Ash Plan	RBLC	N.G. fired Soda Ash Rotary Dryer					5/27/1997	0.15	lb/MMBtu			Low NOx Burner / PSD BACT
WY-0034	WY	Solvay Soda Ash JV Trona Mine	RBLC	N.G. fired Trona Calciner						0.05	LB/MMBTU			Low NOx Burner / PSD BACT
WY-0034	WY	Solvay Soda Ash JV Trona Mine	RBLC	N.G. fired Soda Ash Rotary Dryer					2/6/1998	0.15	LB/MMBTU			Low NOx Burner / PSD BACT
WY-0035	WY	Texasgulf Soda Ash Plant	RBLC	Soda Ash Rotary Dryer					Oct-97	0.15	lb/MMBtu			Low NOx Burner / PSD BACT
WY-0035	WY	Texasgulf Soda Ash Plant	RBLC	Soda Ash Rotary Dryer					Oct-97	0.15	lb/MMBtu			Low NOx Burner / PSD BACT
WV-0024	WV	WESTERN GREENBRIER CO-GENERATION, LLC	RBLC	CEMENTITIOUS MATERIAL KILN	13	mmbtu	COAL	A	04/26/2006	6	LB/T		LB/T CLINKER, 30-DAY	PERMITTEE WILL ATTEMPT TO CONTROL NOX IN KILN EXHAUST BY VENTING THROUGH CFB SNCR. EFFECTIVENESS, HOWEVER, IS UNKNOWN AT THIS TIME

Table D-2. SO_2 Best Available Control Technology RBLC Search - Kilns/Calciners

ID	State	Company/Facility	Database	Process Type	Permit Type	Throughput	Throughput Units	Primary Fuel	Permit Date	Emission Limit	Limit Unit	Emission Limit (lb/hr)	Avg. Period	Control Type
CA-0653	CA	A & M PRODUCTS	RBLC	ROTARY AGGREGATE DRYER		15	TON AGGREGATE/HR	LPG	04/13/1995	3.7	LBM/DAY	0.15		FUEL SPEC: LPG FIRING
VT-0016	VT	OMYA / VERPOL	RBLC	FLASH DRYER SYSTEM #1, #2 AND #3	D				10/26/1999	0.7	LB/H	0.70		LIMIT ON DISTILLATE FUEL SULFUR CONTENT: < .3% S BY WT
	AK	General Shale Corp.	RBLC	Aggregate Calciner						1.1	lb/hr	1.1		Natural Gas usage, Caustic scrubber and Good Combustion Techniques
AR-0025	AR	GENERAL SHALE PRODUCTS CORPORATION, LLC	RBLC	KILN, AGGREGATE	D	10.4	T/H	NATURAL GAS	05/06/1999	4.9	T/YR	1.12		NATURAL GAS USAGE, WET SCRUBBER, AND GOOD COMBUSTION
TX-0271	TX	CHEMICAL LIME LTD.-- LIME PLANT	RBLC	KILN	D	25	T/H	NATURAL GAS	08/05/1997	1.43	LB/H	1.43		
FL-0224	FL	FLORIDA ROCK INDUSTRIES, INC.	RBLC	KILN, PORTLAND CEMENT	A	14	T/H	COAL	12/23/1996	0.16	LB/T	2.24	CLINKER	FUEL S LIMITS AND PROCESS DESIGN LIMITS.
	OH	First Energy	RBLC	Limestone Dryer						4.38	lb/hr	4.38		Number 2 fuel oil not to exceed 0.39% sulfur, and all fuel oil tested
OR-0036	OR	DURKEE FACILITY	RBLC	KILN	A				02/26/1998	10	PPMV	6.25	3-H AV	LOW SULFUR FUEL RESTRICTIONS
GA-0074	GA	DRY BRANCH KAOLIN CO.	RBLC	CALCINER NO. 4	D			FUEL OIL	11/06/1995	40	TONS/12 CONSEC. MOS.	9.13		SULFUR CONTENT OF FUEL OIL LIMITED TO 0.5 WT %
WI-0090	WI	WESTERN LIME CORPORATION	RBLC	LIME KILN #2, P38, S18	D	123.3	MMBTU/H	COAL	07/23/1996	10	LB/H	10.00		LOW SULFUR COAL, GOOD COMBUSTION
TX-0360	TX	TEXAS LIME	RBLC	LIME KILN NO 4, 4-WS-1	D			COAL	08/02/1999	14.6	LB/H	14.60		NONE INDICATED
TX-0355	TX	PORTLAND CEMENT MANUFACTURING PLANT	RBLC	GRINDING/ PREHEATING/ KILN, K-19	D				06/29/2001	20	LB/H	20.00		NONE INDICATED
NC-0077	NC	CAROLINA STALITE COMPANY - GOLD HILL	RBLC	ROTARY EXPANDING KILN	D	23	T/H	COAL	12/20/2001	21.4	LB/H	21.40		WET LIME SLURRY INJECTION
FL-0110	FL	FL CRUSHED STONE	RBLC	PORTLAND CEMENT MANUFACTURING, KILN	D	83	T/H	COAL	11/17/1995	0.27	LB/T	22.41	CLINKER	PROCESS REMOVES ACID GASES
FL-0271	FL	BRANFORD CEMENT PLANT (SUWANNE)	RBLC	KILN W/IN LINE RAW MILL W/ SNCR AND BAGHOUSE	B	127	T/H clinker	COAL	03/30/2006	0.2	LB/TON CLINKER	25.40	CEMS 24-HR ROLLING AVERAGE	RAW MATERIALS AND PROCESS CONTROL
TX-0452	TX	AUSTIN WHITE LIME COMPANY MCNEIL PLANT & QUARRY	RBLC	KILN NO 3					11/19/2003	28.4	LB/H	28.40		THE KILNS ARE CONTROLLED WITH EITHER A CYCLONE/BAGHOUSE COMBO
FL-0268	FL	BROOKSVILLE CEMENT PLANT (FCS)	RBLC	125 TPH CLINKER KILN AND ASSOCIATED EQUIPMENT	B			COAL	12/20/2004	0.23	LB/TON CLINKER	28.80	24-HR	PROCESS CONTROL AND RAW MATERIALS
MT-0006	MT	CONTINENTAL LIME-INDIAN CREEK OP'N	RBLC	LIME KILNS		500	TPD CAO EACH		03/20/1996	31.8	LBS/HR	31.80		
N/A	GA	Carbo Cermamics, McIntyre Plant	TV Permit	Indirect-fired Rotary Calciner				NG, Propane	12/16/2009	32	lb/hr	32	3 hours/daily	Burning of clean fuels.
WI-0250	WI	GRAYMONT (WI) LLC	RBLC	P50 (S50). PREHEATER EQUIPPED, ROTARY LIME KILN	A	54	T/H STONE	COAL	02/06/2009	0.62	LB/T	33.48	24 HOUR AVERAGE	FUEL SULFUR LIMIT, INHERENT PROCESS COLLECTION OF SULFUR OXIDES.
WI-0233	WI	CLM - SUPERIOR	RBLC	LIME KILN (P50)	A	650	T/D	COAL / PET COKE	08/16/2006	33.7	LB/H	33.70	3 HOUR AVG.	HIGH TEMPERATURE MEMBRANE (PTFE) FABRIC FILTER BAGHOUSE; PREHEATER LIME KILN. 2% FUEL SULFUR LIMIT (FOR COAL OR COAL / PET COKE BLEND).
N/A	GA	Carbo Cermamics, Toomsboro Plant	TV Permit	Direct-fired Calciner/Kilns (4)				NG, Propane	12/16/2009	34.25	lb/hr	34.25	3 hours/daily	Analyzing of sulfur content/stack testing. Burning of clean fuels
N/A	GA	Carbo Cermamics, McIntyre Plant	TV Permit	Kiln (Rotary Calciner)				NG, Propane	12/16/2009	34.25	lb/hr	34.25	3 hours/daily	Burning of clean fuels.
N/A	GA	Carbo Cermamics, McIntyre Plant	TV Permit	Kiln (Rotary Calciner)				NG, Propane	12/16/2009	34.25	lb/hr	34.25	3 hours/daily	Burning of clean fuels.
N/A	GA	Carbo Cermamics, McIntyre Plant	TV Permit	Raw Materials Calciner				NG, Propane	12/21/2010	34.25	lb/hr	34.25	3 hours/daily	Wet Scrubber
FL-0267	FL	THOMPSON S. BAKER- CEMENT PLANT (FRI)	RBLC	IN LINE KILN/RAW MILL WITH ESP AND SNCR	B			COAL	11/05/2004	0.28	LB/TON CLINKER	35.00	24 HR	PROCESS CONTROL AND RAW MATERIALS IN FLORIDA
SC-0053	SC	PALMETTO LIME, LLC	RBLC	VERTICAL SHAFT KILNS (LIME MANUFACTURING)	A	1200	T/D		12/12/1997	0.71	LB/T	35.50		NATURAL GAS & 1% SULFUR FUEL. ALSO, SULFUR REACTS WITH LIME IN KILN & IS REMOVED BY BAGHOUSE OR WITH THE PRODUCT.
UT-0054	UT	CONTINENTAL LIME INC. - CRICKET MTN. LIME PLANT	RBLC	KILN, #4		1200	T/D, LIME	NATURAL GAS	01/10/1996	38.4	LB/H	38.40		
NV-0032	NV	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.	RBLC	CEMENT KILN/CLINKER COOLER FACILITY		0			10/24/1995	0.416	LB/TON CLINKER PROD.	47.49		FUEL SPEC: LIMIT FUEL TO COAL WITH 1% SULFUR (COAL SULFUR ANALYSIS)
AZ-0052	AZ	ARIZONA PORTLAND CEMENT	RBLC	KILN	C	300	T/H	COAL	12/16/2008	0.16	LB/T CLINKER	48.00	30 DAY AVERAGE	
FL-0139	FL	SUWANNEE AMERICAN CEMENT COMPANY, INC.	RBLC	IN LINE KILN & RAW MILL	A	178	T/H	NATURAL GAS	06/01/2000	0.27	LB/T	48.06	CLINKER	LOW SULFUR MATERIALS & PROCESS CONTROL
PA-0241	PA	GRAYMONT BELLEFONTE PLANT	RBLC	# 7 LIME KILN	D	1050	T/D	COAL/PETROLEUM COKE	07/09/2004	213	T/YR	48.63		
OR-0042	OR	EAGLE- PICHER VALE, OREGON PLANT	RBLC	DRYER 1/CALCINER 1	A	2990400	LB/WK	NATURAL GAS	05/23/2003	60	% REDUCTION	49.84		OXIDIZED, LOW SULFUR ORES CAN BE OBTAINED BY SELECTIVE MINING OF THE UPPER STRATA OF THE DEPOSITS. SULFUR IS PRESENT IN RAW DE ORES AT VARYING LEVELS DEPENDING ON THE PARTICULAR GEOLOGIC FORMATION
OR-0042	OR	EAGLE- PICHER VALE, OREGON PLANT	RBLC	DRYER 2/CALCINER 2	A	3124800	LB/WK	NATURAL GAS	05/23/2003	60	%SO2 REDUCTION	52.08		OXIDIZED, LOW SULFUR ORES CAN BE OBTAINED BY SELECTIVE MINING THE UPPER STRATA OF THE DEPOSITS. SULFUR IS PRESENT IN RAW DE ORES AT VARYING LEVELS DEPENDING ON THE PARTICULAR GEOLOGIC FORMATION PROCESS
MI-0383	MI	WESTERN LIME CORPORATION	RBLC	LIME KILN	A	186.3	MMBTU/H	COAL AND PETROLEUM COKE MIXTURE	01/30/2004	60.2	LB/H	60.20		PREHEATER AND BAGHOUSE COMBINATION
MT-0008	MT	CONTINENTAL LIME INC.	RBLC	KILNS, LIME 2		106	MMBTU/H EACH		06/20/1997	63.5	LB/H EACH KILN	63.50		ALKALINE PROCESS OF THE KILN ITSELF
MT-0012	MT	CONTINENTAL LIME INC.	RBLC	KILN-LIME, TWO		0			11/19/1997	63.5	LB/H EACH	63.50		BAGHOUSES, 75000 ACFM AT 470F WITH APPROX. 17000 SQ.FT AND AN AIR-TO-CLOTH RATIO OF 4:4:1.
OH-0321	OH	MARTIN MARIETTA MATERIALS	RBLC	ROTARY LIME KILN	B	18000	LB/H	COAL, COKE, NATURAL GAS	11/13/2008	279.23	T/YR	63.75	PER ROLLING 12-MONTH PERIOD	
AR-0028	AR	ARKANSAS LIME COMPANY	RBLC	KILN, LIME	A	625	T/D LIME	COAL/COKE	09/14/1999	65.2	LB/H	65.20		RESTRICTION ON THE SULFUR CONTENT OF THE FUEL USED TO FIRE THE LIME KILN (MAX 4% ON A DAILY BASIS AND 3% ON A ROLLING 30 DAY AVERAGE).
PA-0241	PA	GRAYMONT BELLEFONTE PLANT	RBLC	# 7 LIME KILN	D	1050	T/D	COAL/PETROLEUM COKE	07/09/2004	92.83	LB/H	92.83		LOW SULFUR FUEL AND WET SCRUBBER
TX-0360	TX	TEXAS LIME	RBLC	LIME KILN NO 6, 6-WS-1	D	850	T/D CAO	COAL	08/02/1999	93.1	LB/H	93.10		NONE INDICATED
IL-0057	IL	ILLINOIS CEMENT COMPANY	RBLC	KILN, CEMENT, PREHEATER-PRECALCINER	D	3000	TON/D CEMENT CLINKER		06/12/1998	0.8	LB/T CLINKER	100.00		INHERENT ABSORPTION OF SO2 IN PRODUCT
UT-0062	UT	HOLNAM, DEVIL'S SLIDE PLANT	RBLC	KILN	D			COAL	05/13/1996	110	LB/H	110.00		LOW SULFUR FUELS
TX-0452	TX	AUSTIN WHITE LIME COMPANY MCNEIL PLANT & QUARRY	RBLC	KILN NO 1 AND 2					11/19/2003	117.8	LB/H	117.80		THE KILNS ARE CONTROLLED WITH EITHER A CYCLONE/WET SCRUBBER COMBO
AL-0220	AL	CHEMICAL LIME COMPANY - O"NEAL PLANT	RBLC	KILN 1 & COOLER	B	1500	T/D	COAL	03/23/2005	128.12	LB/H	128.12	3HR AVERAGE	
AL-0220	AL	CHEMICAL LIME COMPANY - O"NEAL PLANT	RBLC	KILN 2 & COOLER	B	1500	T/D	COAL	03/23/2005	128.12	LB/H	128.12	3-HR	
CO-0047	CO	HOLNAM, FLORENCE	RBLC	KILN/PREHEATER/BYPASS & CLINKER COOLER EXHAUST	D			COAL	07/29/1999	623.23	T/YR	142.29		WET LIME SCRUBBER
IL-0084	IL	VULCAN MATERIALS	RBLC	LIME KILN	D	1296	T/D		10/28/2002	2.76	LB/T	149.04	LB/T STONE FEED	BAGHOUSE AND SCRUBBER
IA-0070	IA	LEHIGH CEMENT COMPANY - MASON CITY PLANT	RBLC	KILN/CALCINER/PREHEATER	D	150	T/H	COAL	12/11/2003	1.01	LB/T	151.50	LB/T OF CLINKER	WET SCRUBBER.
AL-0200	AL	CEMEX, INC.	RBLC	KILN, CEMENT	D	230	T/H	COAL	09/13/2002	160	LB/H	160.00		
CO-0043	CO	RIO GRANDE PORTLAND CEMENT CORP.	RBLC	PREHEATER/PRECALCINER, KILN	A	950000	T/YR		09/25/2000	1.99	LB/T	215.81		RAW MATERIALS QUARRY WILL BE MANAGED FOR OPTIMUM SULFUR CONTENTS. SO2 WILL BE ABSORBED IN 5-STAGE PRECALCINER/PREHEATER/KILN AND RAW MILL. EMISSION LIMIT IN LB/T OF CLINKER, 12-MO ROLLING AVG.
TX-0536	TX	SEADRIFT COKE	RBLC	CALCINERS PETROLEUM	A	1340	T/D	NATURAL GAS	04/20/2009	957	T/YR	218.49		COMPANY DID A COST ANALYSIS TO COST OUT OF CONTROLS FOR SO2 CONTROLS.
GA-0134	GA	HOUSTON AMERICAN CEMENT PLANT	RBLC	MAIN KILN STACK ST35	A	229	T/H OF DRY FEED	COAL	06/19/2007	1	LB/T CLINKER	229.00	30 DAY ROLLING BASED ON SO2 CEMS	JUDICIOUS SELECTION/USE OF RAW MATERIALS AND , AS NECESSARY, USE OF HYDRATED LIME INJECTION.
MD-0027	MD	LEHIGH PORTLAND CEMENT COMPANY	RBLC	CEMENT MANUFACTURING, PREHEATER/PRECALCINER KILN	D	2214000	T/YR	COAL	06/08/2000	1041	T/YR	237.67		SO2 EMISSION CONTROL OPTIONS INCLUDE THE INSTALLATION OF A 5-STAGE PREHEATER/PRECALCINER PYROPROCESSING PLANT AND THE USE OF RAW MATERIAL WHICH CONTAINS LESS THAN 0.03% SULFUR
GA-0136	GA	CEMEX SOUTHEAST, LLC	RBLC	MAIN KILN STACK K218	B	270	T/H OF DRY FEED	COAL	01/27/2010	1	LB/T CLINKER	270.00	30-DAY ROLLING AVG.	JUDICIOUS SELECTION/USE OF RAW MATERIALS AND , AS NECESSARY, USE OF HYDRATED LIME INJECTION.
PA-0241	PA	GRAYMONT BELLEFONTE PLANT	RBLC	# 6 LIME KILN	D	1200	T/D	COAL/PET COKE	07/09/2004	305	LB/H	305.00	3 HOUR AVG	LOW SULFUR FUEL
WY-0044	WY	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	RBLC	KILN, COAL FIRED		45.3	T/H COAL		03/06/1995	406	LB/H (3 H ROLLING)	406.00		LOW SULFUR COAL AND ABSORPTION OF SO2 BY THE ALKA-LINE RAW MATERIAL
TX-0466	TX	TEXAS LEHIGH CEMENT	RBLC	KILN EXHAUST (4)					02/03/2003	416	LB/H	416.00		BAGHOUSES
KS-0022	KS	MONARCH CEMENT COMPANY	RBLC	2 PRECALCINERS (EACH)	D	120	MMBTU/H	NATURAL GAS	01/27/2000	421	LB/H	421.00		BAGHOUSE
MO-0048	MO	LAFARGE CORPORATION	RBLC	RAW MILL, PREHEATER/PRECALCINER KINL(EP 78)	A	1584071	TONS		08/20/1997	477.3	LB/HR, 3 HR AVG	477.30		INHERENT DRY SCRUBBING
IN-0112	IN	LONE STAR INDUSTRIES, INC.	RBLC	CEMENT KILN, WET PROCESS, COAL	D	75	T/H	COAL	09/18/1998	543	LB/H	543.00		SULFUR CONTENT OF COAL SHALL NOT EXCEED 3 PERCENT SULFUR.
SD-0003	SD	GCC DACOTAH	RBLC	ROTARY KILN #6	D	2250	T/D	CLINKER	04/10/2003	632	LB/H	632.00		INHERENT SCRUBBING EFFECT OF PROCESSING LIMESTONE
IN-0081	IN	LONE STAR INDUSTRIES, INC.	RBLC	CEMENT MANUFACTURING, KILN OPERATION	D	360	T/H	COAL	04/16/1999	3317	T/YR	757.31		
CO-0048	CO	HOLNAM, LAPORTE CO.	RBLC	CALCINER/ KILN	D	584000	T/YR	COAL	09/22/1998	830	LB/H	830.00		SO2 DOES NOT TRIGGER PSD REVIEW. REQUESTED CHANGE IN HOURLY BASIS SO2 EMISSIONS FROM 215.2 LB/H TO 830 LB/H.
TX-0282	TX	CAPITOL CEMENT DIVISION	RBLC	DRY KILN EXHAUST BAGHOUSE (KS-1A)	D	730000	T/YR CLINKER	SEE PLANT INFO PAGE	09/16/1998	840	LB/H	840.00		DRY SCRUBBER ACHIEVEING AT LEAST 30% REDUCTION, OPERATIONAL NO LESS THAN 95% OF THE TIME KILN IS OPERATING. NO LATER THAN 7/1/02 ADDITIONAL CONTROLS (WET SCRUBBER OR EQUIVALENT) WILL BE INSTALLED
OH-0270	OH	CARMEUSE LIME - MAPLE GROVE FACILITY	RBLC	ROTARY KILN (2)	A	650	T/D	COAL, COKE, NG	10/14/2003	1102	LB/H	1102.00	FOR EACH KILN	
IA-0052	IA	LAFARGE CORPORATION	RBLC	CEMENT MANUFACTURING, PREHEATER/PRECALCINER KILN	D	3488	T/D	COAL	07/01/2002	4850	TONS/YR	1107.31		DRY SCRUBBER EQUIVALENT-NOT AN ADD ON CONTROL. LIME IS GENERATED FROM LIMESTONE IN FEED AND COMES INTO CONTACT WITH SO2 AND SOME SO2 CAPTURED IN WASTE KILN DUST. ALTERNATE EMISSION LIMIT IS NAAQS. ALSO 66,500 LB/D.
TX-0282	TX	CAPITOL CEMENT DIVISION	RBLC	WET KILN EXHAUST BAGHOUSE (KS-1B)	D	378650	T/YR CLINKER	SEE PLANT INFO PAGE	09/16/1998	1200	LB/H	1200.00		NONE INDICATED.
MI-0287	MI	HOLNAM, INC.	RBLC	CEMENT KILNS, WET PROCESS (2)	D	100	T/H FEED	COAL	03/20/2000	21.7	LB/T	2170.00		SULFUR IN FUEL LIMIT HAS BEEN DROPPED IN FAVOR OF CEMS. EXISTING LIMIT DOES NOT REFLECT ANTICIPATED 85% REDUCTION IN SLURRY-SCRUBBER. CONTROL BY BAGHOUSE, THEN SCRUBBER.
MO-0059	MO	CONTINENTAL CEMENT COMPANY, LLC	RBLC	ROTARY KILN	A	183	T/H	COAL	09/24/2002	12	LB/T	2196.00	lb/t clinker, 3-hr rolling avg	WET SCRUBBER
TX-0282	TX	CAPITOL CEMENT DIVISION	RBLC	DRY/WET KILN & ALKALI BYPASS BAGHOUSE STACK (KS-1)	D		SEE NOTES	SEE PLANT INFORMATIO	09/16/1998	2400	LB/H	2400.00		DRY SCRUBBER. NO LATER THAN 7/1/02, ADDITIONAL CONTROL OF A WET SCRUBBER OR EQUIV SHALL BE INSTALLED. BOTH SCRUBBERS CONTROL SO2 FROM KS-1A, WHICH IS INCLUDED IN KS-1.
MI-0354	MI	HOLNAM, INC	RBLC	CEMENT KILNS, WET PROCESS, (2)	A	100	T/H	COAL	06/23/1998	11940	T/YR	2726.03	combined	SULFUR IN FUEL LIMITED TO 2.5% MAX, 2.17% ANNUAL AVERAGE. SOME SO2 REMOVED IN PROCESS AND CONTROL.
TX-0279	TX	NORTH TEXAS CEMENT COMPANY	RBLC	MAIN KILN/SCRUBBER STACK	A	3100	T/D CLINKER	COAL	03/04/1999	2840	LB/H	2840.00		SCRUBBER AND BAGHOUSE

Table D-3. CO Best Available Control Technology RBLC Search - Kilns/Calciners

ID	State	Company/Facility	Database	Process Type	Throughput	Throughput Units	Primary Fuel	Permit Type	Permit Date	Emission Limit	Limit Unit	Emission Limit (lb/hr)	Avg. Period	Control Type
OK-0111	OK	MUSKOGEE PORCELAIN FLOOR TILE PLT	RBLC	KILNS					10/14/2005	1.97	LB/H	1.97		GOOD COMBUSTION
WV-0024	WV	WESTERN GREENBRIER CO-GENERATION, LLC	RBLC	CEMENTITIOUS MATERIAL KILN	13	mmbtu	COAL	A	04/26/2006	0.2	LB/MMBTU	2.6	24-HOUR	COMBUSTION CONTROLS
WY-0044	WY	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	RBLC	KILN, COAL FIRED	45.3	T/H COAL			03/06/1995	3.2	LB/H	3.2		PROPER COMBUSTION/BURNER DESIGN
N/A	GA	Carbo Cermamics, McIntyre Plant	TV Permit	Indirect-fired Rotary Calciner			NG, Propane		12/16/2009	6.3	lb/hr	6.3		Good Combustion / PSD BACT
AR-0025	AR	GENERAL SHALE PRODUCTS CORPORATION, LLC	RBLC	KILN, AGGREGATE	10.4	T/H	NATURAL GAS	D	05/06/1999	9.7	LB/H	9.7		GOOD COMBUSTION
NC-0077	NC	CAROLINA STALITE COMPANY - GOLD HILL	RBLC	ROTARY EXPANDING KILN	23	T/H	COAL	D	12/20/2001	13.6	LB/H	13.6		GOOD ENGINEERING PRACTICE
N/A	GA	Carbo Cermamics, McIntyre Plant	TV Permit	Rotary Dryer			NG, Propane		12/16/2009	13.8	lb/hr	13.8		Good Combustion / PSD BACT
OR-0042	OR	EAGLE- PICHER VALE, OREGON PLANT	RBLC	DRYER 1/CALCINER 1	2990400	LB/WK	NATURAL GAS	A	05/23/2003	19.7	LB/H	19.7	3-hour average	GOOD COMBUSTION CONTROL
N/A	GA	Carbo Cermamics, McIntyre Plant	TV Permit	Raw Materials Calciner			NG, Propane		12/16/2009	20	lb/hr	20		Good Combustion / PSD BACT
N/A	GA	Carbo Cermamics, McIntyre Plant	TV Permit	Kiln (Rotary Calciner)			NG, Propane		12/16/2009	24.5	lb/hr	24.5		Good Combustion / PSD BACT
N/A	GA	Carbo Cermamics, Toomsboro Plant	TV Permit	Direct-fired Calciner/Kilns (4)			NG, Propane		12/16/2009	24.7	lb/hr	24.7	3 hours	Good Combustion Techniques.
FL-0224	FL	FLORIDA ROCK INDUSTRIES, INC.	RBLC	KILN, PORTLAND CEMENT	14	T/H	COAL	A	12/23/1996	2.5	LB/T	35	CLINKER	COMBUSTION CONTROLS.
TX-0452	TX	AUSTIN WHITE LIME COMPANY MCNEIL PLANT & QUARRY	RBLC	KILN NO 3					11/19/2003	38.3	LB/H	38.3		THE KILNS ARE CONTROLLED WITH EITHER A CYCLONE/BAGHOUSE COMBO
TX-0282	TX	CAPITOL CEMENT DIVISION	RBLC	WET KILN EXHAUST BAGHOUSE (KS-1B)	378650	T/YR CLINKER	SEE PLANT INFO PAGE	D	09/16/1998	80	LB/H	80		NONE INDICATED.
WI-0250	WI	GRAYMONT (WI) LLC	RBLC	P50 (S50). PREHEATER EQUIPPED, ROTARY LIME KILN	54	T/H STONE	COAL	A	02/06/2009	1.56	LB/T	84.24	24 HR AVG., FIRING LOW ORGANIC STONE	PREHEATER KILN, GOOD OPERATING PRACTICES (GOOD COMBUSTION CONTROL)
TX-0561	TX	CLIFTON LIME PLANT	RBLC	Kiln 3	25	T/H	Coal	C	08/13/2010	3.5	LB/T OF LIME	87.5	30-DAY	Good combustion practices and proper kiln design
MT-0012	MT	CONTINENTAL LIME INC.	RBLC	KILN-LIME, TWO	0				11/19/1997	131	LB/H EACH KILN	131		BAGHOUSE, 75000 ACFM AT 470F WITH APPROX. 17000 SQ.FT AND AN AIR-TO-CLOTH RATIO OF 4:4:1
FL-0110	FL	FL CRUSHED STONE	RBLC	PORTLAND CEMENT MANUFACTURING, KILN	83	T/H	COAL	D	11/17/1995	2	LB/T	166	CLINKER, 1 HR	GOOD COMBUSTION
MO-0048	MO	LAFARGE CORPORATION	RBLC	RAW MILL, PREHEATER/PRECALCINER KINL(EP 78)	1584071	TONS		A	08/20/1997	842	TON/YR	192.24		GOOD COMBUSTION PRACTICES
FL-0173	FL	SOUTHDOWN, INC.	RBLC	PORTLAND CEMENT, KILN 1	165	T/H		D	06/27/1997	1.2	LB/T	198	lb/t per hour kiln feed	COMBUSTION CONTROLS
CO-0043	CO	RIO GRANDE PORTLAND CEMENT CORP.	RBLC	PREHEATER/PRECALCINER, KILN	950000	T/YR		A	09/25/2000	2.11	LB/T	228.82		MULTI-STAGE COMBUSTION AND GOOD COMBUSTION MANAGEMENT PRACTICES. EMISSION LIMIT IN LB/T OF CLINKER. LB/T LIMIT IS 12-MO ROLLING AVG.
FL-0271	FL	BRANFORD CEMENT PLANT (SUWANNE)	RBLC	KILN W/IN LINE RAW MILL W/ SNCR AND BAGHOUSE	127	T/H clinker	COAL	B	03/30/2006	2.9	LB/TON CLINKER	368.3	CEMS 30 DAYS ROLLING AVERAGE	GOOD COMBUSTION AND PROCESS CONTROL
UT-0062	UT	HOLNAM, DEVIL'S SLIDE PLANT	RBLC	KILN			COAL	D	05/13/1996	438	LB/H	438		COMBUSTION CONTROLS
VA-0283	VA	ROANOKE CEMENT	RBLC	CEMENT KILN SYSTEM, #5	1300000	T/YR	COAL	D	06/13/2003	3	LB/T	445.21		PROCESS CONTROL/GOOD COMBUSTION PRACTICES
FL-0267	FL	THOMPSON S. BAKER- CEMENT PLANT (FRI)	RBLC	IN LINE KILN/RAW MILL WITH ESP AND SNCR			COAL	B	11/05/2004	3.6	LB/T	450	24 HR	PROCESS CONTROL
FL-0268	FL	BROOKSVILLE CEMENT PLANT (FCS)	RBLC	125 TPH CLINKER KILN AND ASSOCIATED EQUIPMENT			COAL	B	12/20/2004	3.6	LB/TON CLINKER	450	24 HR	PROCESS CONTROL AND RAW MATERIALS.
TX-0355	TX	PORTLAND CEMENT MANUFACTURING PLANT	RBLC	GRINDING/ PREHEATING/ KILN, K-19				D	06/29/2001	460	LB/H	460		GOOD COMBUSTION PRACTICES AND GOOD COMBUSTION UNIT DESIGN.
OR-0022	OR	ASH GROVE CEMENT COMPANY	RBLC	PYROPROCESSING (KILN)	113	TON CLINKER/H	NATURAL GAS	A	03/10/1997	490	LB/H	490		GOOD COMBUSTION PRACTICES AS MONITORED BY CONTINUOUS CO AND O2 MONITORS (8-HR AVG)
OR-0036	OR	DURKEE FACILITY	RBLC	KILN				A	02/26/1998	490	LB/H	490	8-H AV	NONE INDICATED
FL-0270	FL	TITAN FLORIDA PENNSUCO CEMENT PLANT	RBLC	KILN WITH IN LINE RAW MILL	250	T/H	COAL	C	12/02/2005	2	LB/T CLINKER	500	30 OPERATING-DAY	GOOD COMBUSTION
TX-0282	TX	CAPITOL CEMENT DIVISION	RBLC	DRY KILN EXHAUST BAGHOUSE (KS-1A)	730000	T/YR CLINKER	SEE PLANT INFO PAGE	D	09/16/1998	522.5	LB/H	522.5		NONE INDICATED.
WA-0307	WA	PORTLAND CEMENT CLINKERING PLANT	RBLC	KILN EXHAUST STACK				D	10/05/2001	1045	PPM @ 10% O2	538		NONE INDICATED.
IA-0070	IA	LEHIGH CEMENT COMPANY - MASON CITY PLANT	RBLC	KILN/CALCINER/PREHEATER	150	T/H	COAL	D	12/11/2003	3.7	LB/T	555	LB/T OF CLINKER	PROPER KILN DESIGN AND OPERATION.
CO-0048	CO	HOLNAM, LAPORTE CO.	RBLC	CALCINER/ KILN	584000	T/YR	COAL	D	09/22/1998	566	LB/H	566		CO DOES NOT TRIGGER PSD.
MI-0287	MI	HOLNAM, INC.	RBLC	CEMENT KILNS, WET PROCESS (2)	100	T/H FEED	COAL	D	03/20/2000	6.4	LB/T	640		FABRIC FILTER, SLURRY SCRUBBER, RTO. CURRENT EXISTING LIMIT DOES NOT REFLECT ANTICIPATED 75% REDUCTION IN SCRUBBER AND REGENERATIVE THERMAL OXIDIZER.
FL-0139	FL	SUWANNEE AMERICAN CEMENT COMPANY, INC.	RBLC	IN LINE KILN & RAW MILL	178	T/H	NATURAL GAS	A	06/01/2000	3.6	LB/T	640.8	CLINKER	COMBUSTION CONTROL
NV-0032	NV	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.	RBLC	CEMENT KILN/CLINKER COOLER FACILITY	0				10/24/1995	5.67	LB/TON CLINKER PROD.	647.26		GOOD COMBUSTION PRACTICE. AIR/FUEL RATIO CONTROL SYSTEM
IA-0052	IA	LAFARGE CORPORATION	RBLC	CEMENT MANUFACTURING, PREHEATER/PRECALCINER KILN	3488	T/D	COAL	D	07/01/2002	4.5	LB/TON OF CLINKER	654		GOOD COMBUSTION PRACTICES
GA-0134	GA	HOUSTON AMERICAN CEMENT PLANT	RBLC	MAIN KILN STACK ST35	229	T/H OF DRY FEED	COAL	A	06/19/2007	2.9	LB/T CLINKER	664.1	30-DAY ROLLING AVG ON CO CEMS	PROPER EQUIPMENT DESIGN AND GOOD COMBUSTION OPERATING PRACTICE
IN-0081	IN	LONE STAR INDUSTRIES, INC.	RBLC	CEMENT MANUFACTURING, KILN OPERATION	360	T/H	COAL	D	04/16/1999	2930	T/YR	668.95		GOOD COMBUSTION PRACTICES
TX-0282	TX	CAPITOL CEMENT DIVISION	RBLC	DRY/WET KILN & ALKALI BYPASS BAGHOUSE STACK (KS-1)		SEE NOTES	SEE PLANT INFORMATIO	D	09/16/1998	702.5	LB/H	702.5		NONE INDICATED.
MD-0027	MD	LEHIGH PORTLAND CEMENT COMPANY	RBLC	CEMENT MANUFACTURING, PREHEATER/PRECALCINER KILN	2214000	T/YR	COAL	D	06/08/2000	3328	T/YR	759.82		THE BACT DETERMINED FOR CO IN THIS CASE IS PROCESS MODIFICATION AND OPERATIONAL MONITORING. ANY ADD ON CONTROL SUCH AS THERMAL OR CATALYTIC OXIDATION IS NOT ENVIRONMENTALLY FEASIBLE. LIMIT IS FOR ANY ROLLING 12 MONTH PERIOD
GA-0136	GA	CEMEX SOUTHEAST, LLC	RBLC	MAIN KILN STACK K218	270	T/H OF DRY FEED	COAL	B	01/27/2010	2.9	LB/T CLINKER	783	30-DAY ROLLING AVG. BASED ON CO CEMS	PROPER EQUIPMENT DESIGN AND GOOD COMBUSTION OPERATING PRACTICE
CO-0047	CO	HOLNAM, FLORENCE	RBLC	KILN/PREHEATER/BYPASS & CLINKER COOLER EXHAUST			COAL	D	07/29/1999	3988.7	T/YR	910.66		GOOD COMBUSTION
MO-0059	MO	CONTINENTAL CEMENT COMPANY, LLC	RBLC	ROTARY KILN	183	T/H	COAL	A	09/24/2002	12	LB/T	2196	lb/t clinker, 1-hr rolling avg	PYROCLON
TX-0279	TX	NORTH TEXAS CEMENT COMPANY	RBLC	MAIN KILN/SCRUBBER STACK	3100	T/D CLINKER	COAL	A	03/04/1999	2209	LB/H	2209		GOOD COMBUSTION PRACTICES.
AR-0092	AR	ASH GROVE CEMENT COMPANY	RBLC	PH/PC KILN				A	05/15/2007	2500	LB/H	2500	8-HR AVERAGE	GOOD COMBUSTION PRACTICES
SD-0003	SD	GCC DACOTAH	RBLC	ROTARY KILN #6	2250	T/D	CLINKER	D	04/10/2003	3250	LB/H	3250		GOOD COMBUSTION PRACTICES
WV-0022	WV	MARTINSBURG PLANT	RBLC	PRE-HEATER/PRE-CALCINER KILN	5900	T/D	COAL	C	06/02/2005	3960	LB/H	3960	1-HR AVG.	GOOD COMBUSTION PRACTICES
KS-0020	KS	ASH GROVE CEMENT COMPANY	RBLC	PORTLAND CEMENT PLANT, PREHEATER/PRECALCINER KILN	331	T/H	COAL	A	08/26/1999	5000	LB/H	5000		COMPUTERISED PROCESS/MONITORING CONTROL EQUIPMENT WITH EMPLOYEE TRAINING TO IMPLEMENT GOOD COMBUSTION PRACTICES.
KS-0022	KS	MONARCH CEMENT COMPANY	RBLC	2 PRECALCINERS (EACH)	120	MMBTU/H	NATURAL GAS	D	01/27/2000	5000	LB/H	5000		NATURAL GAS
TX-0466	TX	TEXAS LEHIGH CEMENT	RBLC	KILN EXHAUST (4)					02/03/2003	5298	LB/H	5298		BAGHOUSES

1. Permit types: A = New/Greenfield facility, B = Adding new process to an existing facility, C = Modifying an existing process at an existing facility, D = Both B & C.

Table D-4. PM Best Available Control Technology RBLC Search - Kilns/Calciners

ID	State	Company/Facility	Database	Process Type	Permit Type	Throughput	Throughput Units	Primary Fuel	Permit Date	Pollutant	Emission Limit	Limit Unit	Emission Limit (lb/hr)	Avg. Period	Control Type
MO-0059	MO	CONTINENTAL CEMENT COMPANY, LLC	RBLC	ROTARY KILN	A	183	T/H	COAL	09/24/2002	Particulate matter, filterable < 10 µ (FPM10)	99	% REDUCTION			FABRIC FILTER
WY-0055	WY	WOLD TRONA COMPANY, INC.	RBLC	TRONA ORE CALCINER STACK (E5) (E15)	A	212020	ACFM	NATURAL GAS	04/27/2000	Particulate matter, filterable < 10 µ (FPM10)	0.003	GR/DSCF	1.6		WET SCRUBBER.
WY-0038	WY	WOLD TRONA CO.	RBLC	CALCINER & CALCINER BOILER, (2)	D	213.15	T/H		05/02/1995	Particulate Matter (PM)	0.005	GR/DSCF	2.52		WET SCRUBBER (VENTURI) AND PACKED TOWER CONDENSER ON CALCINER
WA-0307	WA	PORTLAND CEMENT CLINKERING PLANT	RBLC	KILN EXHAUST STACK	D				10/05/2001	Particulate matter, filterable < 2.5 µ (FPM2.5)	0.005	GR/DSCF	0.005	24 H PERIOD	BAGHOUSE STACK
AZ-0052	AZ	ARIZONA PORTLAND CEMENT	RBLC	KILN	C	300	T/H	COAL	12/16/2008	Particulate matter, filterable < 10 µ (FPM10)	0.008	G/DSCF	0.008		BAGHOUSE
N/A	GA	Carbo Cermamics, Toomsboro Plant	TV Permit	Direct-fired Calciner/Kilns (4)	B			NG, Propane	12/16/2009		0.01	gr/dscf		3 hours	Baghouse
N/A	GA	Carbo Cermamics, McIntyre Plant	TV Permit	Indirect-fired Rotary Calciner				NG, Propane	5/12/2008		0.01	gr/dscf			Baghouse
N/A	GA	Carbo Cermamics, McIntyre Plant	TV Permit	Kiln (Rotary Calciner)				NG, Propane	5/12/2008		0.01	gr/dscf			Baghouse
N/A	GA	Carbo Cermamics, McIntyre Plant	TV Permit Amendment	Raw Materials Calciner	D			NG, Propane	12/21/2010		0.01	gr/dscf			Wet Scrubber
VT-0016	VT	OMYA / VERPOL	RBLC	FLASH DRYER SYSTEM #1, #2 AND #3	D				10/26/1999	Particulate matter, filterable < 10 µ (FPM10)	0.01	GR/DSCF	0.86		FABRIC FILTERS
WY-0035	WY	TEXASGULF SODA ASH PLANT	RBLC	ROTARY DRYER, SODA ASH		122	T/H WET CRYSTAL FEED		10/13/1997	Particulate Matter (PM)	0.01	GR/DSCF	3.35		ELECTROSTATIC PRECIPITATOR 124,000 ACFM
IN-0081	IN	LONE STAR INDUSTRIES, INC.	RBLC	CEMENT MANUFACTURING, KILN OPERATION	D	360	T/H	COAL	04/16/1999	Particulate matter, filterable < 10 µ (FPM10)	0.014	GR/DSCF	88.7		ESP
WY-0034	WY	SOLVAY SODA ASH JOINT VENTURE TRONA MINE/SODA ASH	RBLC	CALCINER, NATURAL GAS FIRED TRONA		275	T/H TRONA ORE FEED	NATURAL GAS	02/06/1998	Particulate Matter (PM)	0.015	GR/DSCF	0.015		ELECTROSTATIC PRECIPITATOR 264,000ACFM
IN-0081	IN	LONE STAR INDUSTRIES, INC.	RBLC	CEMENT MANUFACTURING, KILN OPERATION	D	360	T/H	COAL	04/16/1999	Particulate matter, filterable (FPM)	0.016	GR/DSCF	91.3		ESP
WY-0036	WY	OCI, WYOMING L.P.-OCI SODA ASH PLANT	RBLC	CALCINER TRONA ORE, NATURAL GAS FIRED		213	T/H ORE FEED RATE	NATURAL GAS	05/27/1997	Particulate Matter (PM)	0.017	GR/DSCF	0.017		ELECTROSTATIC PRECIPITATOR
WY-0036	WY	OCI, WYOMING L.P.-OCI SODA ASH PLANT	RBLC	ROTARY DRYER, SODA ASH, NATURAL GAS FIRED		144	T/H WET CRYSTAL FEED	NATURAL GAS	05/27/1997	Particulate Matter (PM)	0.017	GR/SCF	5.90		ELECTROSTATIC PRECIPITATOR
OR-0036	OR	DURKEE FACILITY	RBLC	KILN FEED FOR PREHEATER	A				02/26/1998	Particulate Matter (PM)	0.019	GR/DSCF	3.75	3-H AV	BAGHOUSE
N/A	GA	Carbo Cermamics, McIntyre Plant	TV Permit Amendment	Rotary Dryer	D			NG, Propane	12/21/2010		0.02	gr/dscf			Baghouse
N/A	GA	Carbo Cermamics, McIntyre Plant	TV Permit Amendment	Rotary Dryer	D			NG, Propane	12/21/2010		0.02	gr/dscf			Baghouse
GA-0059	GA	THIELE KAOLIN CO.	RBLC	KAOLIN PROCESSING FACILITIES	A	40	T/H		01/24/1995	Particulate Matter (PM)	0.02	GR/DSCF	0.02		BAGHOUSE
N/A	GA	Engelhard Corporation-Edgar Plant	Issued Title V permit	Direct-fired Rotary Calciner							0.025	gr/dscf			Baghouse
NC-0077	NC	CAROLINA STALITE COMPANY - GOLD HILL	RBLC	ROTARY EXPANDING KILN	D	23	T/H	COAL	12/20/2001	Particulate matter, filterable < 10 µ (FPM10)	0.04	GR/DSCF	7.2		BAGFILTERS
GA-0074	GA	DRY BRANCH KAOLIN CO.	RBLC	CALCINER NO. 4	D			FUEL OIL	11/06/1995	Particulate Matter (PM)	0.04	GR/DSCF	0.04		ESP
OR-0042	OR	EAGLE- PICHER VALE, OREGON PLANT	RBLC	DRYER 2/CALCINER 2	A	3124800	LB/WK	NATURAL GAS	05/23/2003	Particulate matter, filterable (FPM)	0.04	GR/DSCF	0.04		BAGHOUSE
OR-0042	OR	EAGLE- PICHER VALE, OREGON PLANT	RBLC	DRYER 2/CALCINER 2	A	3124800	LB/WK	NATURAL GAS	05/23/2003	Particulate Matter (PM)	0.1	GR/DSCF	0.1		FABRIC FILTER MODEL 289-10 PULSE-JET BAGHOUSE WITH AIR TO CLOTH RATIO OF 2.0:1
MI-0354	MI	HOLNAM, INC	RBLC	CEMENT KILNS, WET PROCESS, (2)	A	100	T/H	COAL	06/23/1998	Particulate Matter (PM)	0.1	LB/1000 LB	5	gases	BAGHOUSE UNDER PERMIT 60-71G. 15% OPACITY CEMS. MAXIMUM TDF FEED 4.6 T/H COMBINED.
OR-0036	OR	DURKEE FACILITY	RBLC	KILN	A				02/26/1998	Particulate Matter (PM)	436	LB/D	18.17	DAILY AVER	BAGHOUSE
TX-0282	TX	CAPITOL CEMENT DIVISION	RBLC	KILN DUST DROP TO PILES (F-P-7)	D				09/16/1998	Particulate Matter (PM)	0.01	LB/H	0.01	LESS THAN	NONE INDICATED.
TX-0282	TX	CAPITOL CEMENT DIVISION	RBLC	CKD DRY KILN PUG MILL TO TRUCK (F-P-12)	D				09/16/1998	Particulate Matter (PM)	0.01	LB/H	0.01	LESS THAN	INCOMING AND OUTGOING RR CARS AND TRUCKS USED IN TRANSPORTING CEMENT, CLINKER, COAL, AND PETCOKE SHALL BE CLEANED AND MAINTAINED, AS NECESSARY, TO MINIMIZE FUGITIVE EMISSIONS.
TX-0452	TX	AUSTIN WHITE LIME COMPANY MCNEIL PLANT & QUARRY	RBLC	KILN NO 3 DUST BIN					11/19/2003	Particulate Matter (PM)	0.17	LB/H	0.17		THE FUEL HANDLING AND PRODUCT HANDLING EQUIPMENT AND STORAGE BINS ARE CONTROLLED WITH DUST COLLECTORS, ENCLOSURES, COVERED SPOUTS, AND WATER SPRAYS FOR PM CONTROL
TX-0271	TX	CHEMICAL LIME LTD.-- LIME PLANT	RBLC	KILN STONE FEED HOPPER	D				08/05/1997	Particulate matter, filterable < 10 µ (FPM10)	0.17	LB/H	0.17		BAGHOUSE
TX-0452	TX	AUSTIN WHITE LIME COMPANY MCNEIL PLANT & QUARRY	RBLC	KILN NO 3 DUST BIN					11/19/2003	Particulate Matter (PM)	0.18	LB/H	0.18		THE FUEL HANDLING AND PRODUCT HANDLING EQUIPMENT AND STORAGE BINS ARE CONTROLLED WITH DUST COLLECTORS, ENCLOSURES, COVERED SPOUTS, AND WATER SPRAYS FOR PM CONTROL
LA-0209	LA	GRAVELITE DIVISION	RBLC	ROTARY KILNS, NOS. 1-4	C	22	T/H	COAL	06/28/2006	Particulate matter, filterable < 10 µ (FPM10)	0.97	LB/H	0.97	HOURLY MAXIMUM	VENTURI SCRUBBER
TX-0271	TX	CHEMICAL LIME LTD.-- LIME PLANT	RBLC	KILN	D	25	T/H	NATURAL GAS	08/05/1997	Particulate matter, filterable < 10 µ (FPM10)	2.96	LB/H	2.96		BAGHOUSE
TX-0452	TX	AUSTIN WHITE LIME COMPANY MCNEIL PLANT & QUARRY	RBLC	KILN NO 1/2 REJECT BIN					11/19/2003	Particulate Matter (PM)	3.66	LB/H	3.66		THE FUEL HANDLING AND PRODUCT HANDLING EQUIPMENT AND STORAGE BINS ARE CONTROLLED WITH DUST COLLECTORS, ENCLOSURES, COVERED SPOUTS, AND WATER SPRAYS FOR PM CONTROL
WA-0307	WA	PORTLAND CEMENT CLINKERING PLANT	RBLC	KILN EXHAUST STACK	D				10/05/2001	Particulate Matter (PM)	10.6	LB/H	10.6		BAGHOUSE
TX-0452	TX	AUSTIN WHITE LIME COMPANY MCNEIL PLANT & QUARRY	RBLC	KILN NO 3					11/19/2003	Particulate Matter (PM)	13.2	LB/H	13.2		THE KILNS ARE CONTROLLED WITH EITHER A CYCLONE/BAGHOUSE COMBO
UT-0054	UT	CONTINENTAL LIME INC. - CRICKET MTN. LIME PLANT	RBLC	KILN, #4		1200	T/D, LIME	NATURAL GAS	01/10/1996	Particulate matter, filterable < 10 µ (FPM10)	13.4	LB/H	13.4		BAGHOUSE
WY-0044	WY	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	RBLC	KILN, COAL FIRED		45.3	T/H COAL		03/06/1995	Particulate Matter (PM)	13.59	LB/H	13.59		ELECTROSTATIC PRECIPITATOR (RECONSTRUCT EXISTING)
UT-0062	UT	HOLNAM, DEVIL'S SLIDE PLANT	RBLC	KILN	D			COAL	05/13/1996	Particulate matter, filterable < 10 µ (FPM10)	14	LB/H	14		BAGHOUSE. NOTE: OPACITY LIMIT FOR KILN EXHAUST GASES IS 20%.
OH-0270	OH	CARMEUSE LIME - MAPLE GROVE FACILITY	RBLC	ROTARY KILN (2)	A	650	T/D	COAL, COKE, NG	10/14/2003	Particulate matter, filterable < 10 µ (FPM10)	14.23	LB/H	14.23	for each kiln	BAGHOUSE WITH MAXIMUM OUTLET PM GRAIN LOADING OF 0.021 GRAINS/DSCF
TX-0282	TX	CAPITOL CEMENT DIVISION	RBLC	DRY KILN EXHAUST BAGHOUSE (KS-1A)	D	730000	T/YR CLINKER	SEE PLANT INFO PAGE	09/16/1998	Particulate matter, filterable (FPM)	14.44	LB/H	14.44		BAGHOUSE IS CONTROL.
UT-0059	UT	ASH GROVE CEMENT COMPANY	RBLC	KILN	D	170	T/H	COAL	10/24/1996	Particulate matter, filterable < 10 µ (FPM10)	21.11	LB/H	21.11	@ 170 T/H	BAGHOUSE. EMISSION LIMIT: 21.11 LB/H @ 170 T/H KILN FEED.
CO-0048	CO	HOLNAM, LAPORTE CO.	RBLC	CALCINER/ KILN	D	584000	T/YR	COAL	09/22/1998	Particulate matter, filterable < 10 µ (FPM10)	21.3	LB/H	21.3		BAGHOUSE. SEE NOTE FOR TSP. REQUESTED INCREASE TO 21.3 LB/H FOR EMISSIONS NOT TO EXCEED .3 LB/T OF RAW MATERIAL (AS PER NSPS)
TX-0282	TX	CAPITOL CEMENT DIVISION	RBLC	DRY KILN EXHAUST BAGHOUSE (KS-1A)	D	730000	T/YR CLINKER	SEE PLANT INFO PAGE	09/16/1998	Particulate matter, filterable < 10 µ (FPM10)	21.37	LB/H	21.37	TOTAL PM10	BAGHOUSE IS CONTROL.
UT-0059	UT	ASH GROVE CEMENT COMPANY	RBLC	KILN	D	170	T/H	COAL	10/24/1996	Total Suspended Particulates	23.45	LB/H	23.45	@170 T/H	BAGHOUSE. EMISSION LIMITS 23.45 LB/H @170 T/H KILN FEED RATE.
TX-0282	TX	CAPITOL CEMENT DIVISION	RBLC	DRY KILN EXHAUST BAGHOUSE (KS-1A)	D	730000	T/YR CLINKER	SEE PLANT INFO PAGE	09/16/1998	Particulate Matter (PM)	25.44	LB/H	25.44	TOTAL PM	BAGHOUSE IS CONTROL
CO-0048	CO	HOLNAM, LAPORTE CO.	RBLC	CALCINER/ KILN	D	584000	T/YR	COAL	09/22/1998	Total Suspended Particulates	27.3	LB/H	27.3		BAGHOUSE. SEE FACILITY NOTES: REGULATORY BASIS. REQUESTED LB/H INCREASE FROM 21.5 TO 27.3 LB/H. SEE NOTE - PSD NOT TRIGGERED FOR PM BECAUSE OF NET REDUCTIONS
TX-0279	TX	NORTH TEXAS CEMENT COMPANY	RBLC	MAIN KILN/SCRUBBER STACK	A	3100	T/D CLINKER	COAL	03/04/1999	Particulate Matter (PM)	28	LB/H	28	FRONT-HALF, FED COMPLIANCE	SCRUBBER AND BAGHOUSE
TX-0355	TX	PORTLAND CEMENT MANUFACTURING PLANT	RBLC	GRINDING/ PREHEATING/ KILN, K-19	D				06/29/2001	Particulate matter, filterable (FPM)	32.24	LB/H	32.24		ESP
TX-0355	TX	PORTLAND CEMENT MANUFACTURING PLANT	RBLC	GRINDING/ PREHEATING/ KILN, K-19	D				06/29/2001	Particulate Matter (PM)	36.33	LB/H	36.33		ESP
IN-0112	IN	LONE STAR INDUSTRIES, INC.	RBLC	CEMENT KILN, WET PROCESS, COAL	D	75	T/H	COAL	09/18/1998	Particulate matter, filterable < 10 µ (FPM10)	37.3	LB/H	37.3		ESP
TX-0355	TX	PORTLAND CEMENT MANUFACTURING PLANT	RBLC	GRINDING/ PREHEATING/ KILN, K-19	D				06/29/2001	Particulate matter, filterable < 10 µ (FPM10)	40	LB/H	40		ESP
IN-0112	IN	LONE STAR INDUSTRIES, INC.	RBLC	CEMENT KILN, WET PROCESS, COAL	D	75	T/H	COAL	09/18/1998	Particulate Matter (PM)	40.5	LB/H	40.5		ESP
TX-0452	TX	AUSTIN WHITE LIME COMPANY MCNEIL PLANT & QUARRY	RBLC	KILN NO 1 AND 2					11/19/2003	Particulate Matter (PM)	46.7	LB/H	46.7		THE KILNS ARE CONTROLLED WITH EITHER A CYCLONE/WET SCRUBBER COMBO
TX-0466	TX	TEXAS LEHIGH CEMENT	RBLC	KILN EXHAUST (4)					02/03/2003	Particulate Matter (PM)	95	LB/H	95		BAGHOUSES
MI-0287	MI	HOLNAM, INC.	RBLC	CEMENT KILNS, WET PROCESS (2)	D	100	T/H FEED	COAL	03/20/2000	Particulate Matter (PM)	130	LB/H	130		FABRIC FILTER, SLURRY SCRUBBER, 15% OPACITY APPLIES. ALTERNATE LIMIT IS IN LB/1000 LB GASES @ 6% O2. EXISTING LIMITS DO NOT REFLECT ADDITIONAL 90% ANTICIPATED PM REMOVAL IN SCRUBBER.
TX-0282	TX	CAPITOL CEMENT DIVISION	RBLC	WET KILN EXHAUST BAGHOUSE (KS-1B)	D	378650	T/YR CLINKER	SEE PLANT INFO PAGE	09/16/1998	Particulate matter, filterable < 10 µ (FPM10)	138.3	LB/H	138.3		BAGHOUSE IS CONTROL.
TX-0282	TX	CAPITOL CEMENT DIVISION	RBLC	DRY/WET KILN & ALKALI BYPASS BAGHOUSE STACK (KS-1)	D		SEE NOTES	SEE PLANT INFORMATIO	09/16/1998	Particulate matter, filterable < 10 µ (FPM10)	164.2	LB/H	164.2	TOTAL	BAGHOUSE
NV-0032	NV	GREAT STAR CEMENT CORP./UNITED ROCK PRODUCTS CORP.	RBLC	CEMENT KILN CALCINING		1.6	MILLION TONS		10/24/1995	Particulate matter, filterable < 10 µ (FPM10)	23.7	LB/HR & .015 GR/DSCF	23.7		BAGHOUSE WITH A STACK
MO-0048	MO	LAFARGE CORPORATION	RBLC	RAW MILL, PREHEATER/PRECALCINER KINL(EP 78)	A	1584071	TONS		08/20/1997	Particulate matter, filterable < 10 µ (FPM10)	19.22	LB/HR, 24-HR AVG	19.22		BAGHOUSE
FL-0110	FL	FL CRUSHED STONE	RBLC	PORTLAND CEMENT MANUFACTURING, KILN	D	83	T/H	COAL	11/17/1995	Particulate Matter (PM)	0.02	LB/T	1.66	FEED	FABRIC FILTER
WV-0024	WV	WESTERN GREENBRIER CO-GENERATION, LLC	RBLC	CEMENTITIOUS MATERIAL KILN	A	13	mmbtu	COAL	04/26/2006	Particulate matter, filterable (FPM)	0.065	LB/T		LB/T CLINKER, PER TEST METHOD	BAGHOUSE
FL-0139	FL	SUWANNEE AMERICAN CEMENT COMPANY, INC.	RBLC	IN LINE KILN & RAW MILL	A	178	T/H	NATURAL GAS	06/01/2000	Particulate matter, filterable < 10 µ (FPM10)	0.11	LB/T	19.58		BAGHOUSE
SC-0053	SC	PALMETTO LIME, LLC	RBLC	VERTICAL SHAFT KILNS (LIME MANUFACTURING)	A	1200	T/D		12/12/1997	Particulate matter, filterable < 10 µ (FPM10)	0.12	LB/T	6		BAGHOUSE EFFICIENCY 0.005 GR/DSCF
FL-0139	FL	SUWANNEE AMERICAN CEMENT COMPANY, INC.	RBLC	IN LINE KILN & RAW MILL	A	178	T/H	NATURAL GAS	06/01/2000	Particulate Matter (PM)	0.13	LB/T	23.14		BAGHOUSE
WV-0024	WV	WESTERN GREENBRIER CO-GENERATION, LLC	RBLC	CEMENTITIOUS MATERIAL KILN	A	13	mmbtu	COAL	04/26/2006	Particulate Matter (PM)	0.13	LB/T		LB/T CLINKER, PER TEST METHOD	BAGHOUSE
FL-0173	FL	SOUTHDOWN, INC.	RBLC	PORTLAND CEMENT, KILN 1	D	165	T/H		06/27/1997	Particulate matter, filterable < 10 µ (FPM10)	0.18	LB/T	29.7	lb/t per hour kiln feed	FABRIC FILTERS.
FL-0224	FL	FLORIDA ROCK INDUSTRIES, INC.	RBLC	KILN, PORTLAND CEMENT	A	14	T/H	COAL	12/23/1996	Particulate Matter (PM)	0.2	LB/T	2.8	CLINKER	ESP.
OK-0111	OK	MUSKOGEE PORCELAIN FLOOR TILE PLT	RBLC	KILNS					10/14/2005	Particulate matter, filterable < 10 µ (FPM10)	0.32	LB/T			WET SCRUBBER
IA-0070	IA	LEHIGH CEMENT COMPANY - MASON CITY PLANT	RBLC	KILN/CALCINER/PREHEATER	D	150	T/H	COAL	12/11/2003	Particulate Matter (PM)	0.516	LB/T	77.4	LB/T OF CLINKER	ESP.
MO-0072	MO	CONTINENTAL CEMENT COMPANY, L.L.C.	RBLC	PORTLAND CEMENT KILN	B				07/11/2006	Particulate matter, filterable < 10 µ (FPM10)	0.516	LB/T		CLINK 3-HOUR AVERAGING TIME	BAGHOUSES HAVE BEEN SELECTED AS BACT FOR EACH POINT SOURCE OF PM10 EMISSIONS THAT IS NEW OR MODIFIED
MT-0012	MT	CONTINENTAL LIME INC.	RBLC	KILN-LIME, TWO		0			11/19/1997	Particulate Matter (PM)	0.05	LB/T OF LIMESTONE	0.05		BAG HOUSE FOR 75000 ACFM AT 470F WITH APPROXIMATE-LY 17000 FT2 AND AN AIR-TO-CLOTH RATIO OF 4:4:1.

ID	State	Company/Facility	Database	Process Type	Permit Type	Throughput	Throughput Units	Primary Fuel	Permit Date	Pollutant	Emission Limit	Limit Unit	Emission Limit (lb/hr)	Avg. Period	Control Type
FL-0297	FL	NORTH BROOKSVILLE CEMENT PLANT	RBLC	KILN NO. 3 WITH PREHEATER, CALCINER, IN-LINE RAW MILL AND AIR HEATER	B	550	MMBTU/H	COAL	06/27/2007	Particulate matter, filterable < 10 µ (FPM10)	0.1	LB/T CLINKER		THREE 1-H RUN	FABRIC FILTER
FL-0271	FL	BRANFORD CEMENT PLANT (SUWANNE)	RBLC	KILN W/IN LINE RAW MILL W/ SNCR AND BAGHOUSE	B	127	T/H clinker	COAL	03/30/2006	Particulate Matter (PM)	0.1	LB/TON DR PHF	12.7	AVERAGE OF 3, 1-HR RUNS	BAGHOUSE
GA-0136	GA	CEMEX SOUTHEAST, LLC	RBLC	MAIN KILN STACK K218	B	270	T/H OF DRY FEED	COAL	01/27/2010	Particulate matter, filterable (FPM)	0.153	LB/T PM CLINKER	41.31	AVG. OF THREE 1-HR RUNS/METH. 5	FABRIC FILTERS/BAGHOUSE
FL-0267	FL	THOMPSON S. BAKER- CEMENT PLANT (FRI)	RBLC	IN LINE KILN/RAW MILL WITH ESP AND SNCR	B			COAL	11/05/2004	Particulate matter, filterable < 10 µ (FPM10)	0.2	LB/TON CLINKER	25	3 HR	ESP
FL-0268	FL	BROOKSVILLE CEMENT PLANT (FCS)	RBLC	125 TPH CLINKER KILN AND ASSOCIATED EQUIPMENT	B			COAL	12/20/2004	Particulate matter, filterable < 10 µ (FPM10)	0.2	LB/TON CLINKER	25	3-HR	BAGHOUSE
IL-0057	IL	ILLINOIS CEMENT COMPANY	RBLC	KILN, CEMENT, PREHEATER-PRECALCINER	D	3000	TON/D CEMENT CLINKER		06/12/1998	Particulate Matter (PM)	0.208	LB/T CLINKER	26		FABRIC FILTER
FL-0267	FL	THOMPSON S. BAKER- CEMENT PLANT (FRI)	RBLC	IN LINE KILN/RAW MILL WITH ESP AND SNCR	B			COAL	11/05/2004	Particulate Matter (PM)	0.23	LB/TON CLINKER	28.8	3 HR	ESP
FL-0268	FL	BROOKSVILLE CEMENT PLANT (FCS)	RBLC	125 TPH CLINKER KILN AND ASSOCIATED EQUIPMENT	B			COAL	12/20/2004	Particulate Matter (PM)	0.23	LB/TON CLINKER	28.8	3-HR	BAGHOUSE
IA-0052	IA	LAFARGE CORPORATION	RBLC	CEMENT MANUFACTURING, PREHEATER/PRECALCINER KILN	D	3488	T/D	COAL	07/01/2002	Total Suspended Particulates	0.516	LB/TON OF CLINKER	74.99		BAGHOUSE (LIMIT INCLUDES CONDENSIBLES). ALTERNATE LIMIT IS PER TON OF FEED AND IS BASED ON MACT AND NSPS.
OK-0110	OK	MUSKOGEE PORCELAIN FLOOR TILE PLT	RBLC	KILNS	A				10/21/2005	Particulate matter, filterable < 10 µ (FPM10)	0.032	LB/TON TILE			USE OF NATURAL GAS FUEL
CA-0653	CA	A & M PRODUCTS	RBLC	ROTARY AGGREGATE DRYER		15	TON AGGREGATE/HR	LPG	04/13/1995	Particulate matter, filterable < 10 µ (FPM10)	27.1	LBM/DAY	1.13		BAGHOUSE
CO-0048	CO	HOLNAM, LAPORTE CO.	RBLC	STACKER / RECALCINER DOME	D				09/22/1998	Particulate matter, filterable < 10 µ (FPM10)	0.043	T/YR	0.01		BAGHOUSE. EMISSION LIMITS IN LB/T NOT AVAILABLE.
OH-0270	OH	CARMEUSE LIME - MAPLE GROVE FACILITY	RBLC	KILN DUST HANDLING	A				10/14/2003	Particulate matter, filterable < 10 µ (FPM10)	0.21	T/YR	0.05	FUGITIVE EMISSIONS	WATERING OF DUST AND BAGHOUSE
CO-0047	CO	HOLNAM, FLORENCE	RBLC	CEMENT KILN DUST HAULING	D				07/29/1999	Particulate matter, filterable < 10 µ (FPM10)	1.34	T/YR	0.31		WETTING MATERIAL PRIOR TO PLACEMENT.
AR-0025	AR	GENERAL SHALE PRODUCTS CORPORATION, LLC	RBLC	KILN, AGGREGATE	D	10.4	T/H	NATURAL GAS	05/06/1999	Particulate matter, filterable < 10 µ (FPM10)	21.9	T/YR	5		NATURAL GAS USAGE, WET SCRUBBER, AND GOOD COMBUSTION
CO-0043	CO	RIO GRANDE PORTLAND CEMENT CORP.	RBLC	PREHEATER/PRECALCINER, KILN	A	950000	T/YR		09/25/2000	Particulate matter, filterable < 10 µ (FPM10)	45.9	T/YR	10.48		HIGH TEMPERATURE FILTER BAGHOUSE
MD-0027	MD	LEHIGH PORTLAND CEMENT COMPANY	RBLC	CEMENT MANUFACTURING, PREHEATER/PRECALCINER KILN	D	2214000	T/YR	COAL	06/08/2000	Particulate matter, filterable < 10 µ (FPM10)	96	T/YR	21.92		ENCLOSURE, WET SUPPRESSION SYSTEMS AND PAVED ROADS. CONTROL EFFICIENCIES RANGE FROM 60-90%
CO-0047	CO	HOLNAM, FLORENCE	RBLC	KILN/PREHEATER/BYPASS & CLINKER COOLER EXHAUST	D			COAL	07/29/1999	Total Suspended Particulates	132.1	T/YR	30.16		BAGHOUSE
MD-0027	MD	LEHIGH PORTLAND CEMENT COMPANY	RBLC	CEMENT MANUFACTURING, PREHEATER/PRECALCINER KILN	D	2214000	T/YR	COAL	06/08/2000	Particulate matter, filterable < 10 µ (FPM10)	620	T/YR	141.55		ALL STACKS ARE EQUIPPED WITH BAGHOUSE TO MEET EMISSION LIMIT. KILN STACK 0.015 GR/SCFD; CLINKER COOLER STACK 0.0129 GR/SCFD; OTHER STACKS 0.01 GR/SCFD

1. Permit types: A = New/Greenfield facility, B = Adding new process to an existing facility, C = Modifying an existing process at an existing facility, D = Both B & C.

Table D-5. VOC Best Available Control Technology RBLC Search - Kilns/Calciners

ID	State	Company/Facility	Database	Process Type	Throughput	Throughput Units	Primary Fuel	Permit Type	Permit Date	Emission Limit	Emission Limit Unit	Emission Limit (lb/hr)	Avg. Period	Control Type
TX-0360	TX	TEXAS LIME	RBLC	LIME KILN NO 4, 4-WS-1			COAL	D	08/02/1999	0.1	LB/H	0.1		NONE INDICATED
WY-0036	WY	OCI, WYOMING L.P.-OCI SODA ASH PLANT	RLBC	ROTARY DRYER, SODA ASH, NATURAL GAS FIRED	144	T/H WET CRYSTAL FEED	NATURAL GAS		05/27/1997	0.37	LB/H	0.37		
TX-0452	TX	AUSTIN WHITE LIME COMPANY MCNEIL PLANT & QUARRY	RBLC	KILN NO 1 AND 2					11/19/2003	0.9	LB/H	0.9		THE KILNS ARE CONTROLLED WITH EITHER A CYCLONE/WET SCRUBBER COMBO
TX-0360	TX	TEXAS LIME	RLBC	LIME KILN NO 6, 6-WS-1	850	T/D CAO	COAL	D	08/02/1999	1	LB/H	1		NONE INDICATED
TX-0452	TX	AUSTIN WHITE LIME COMPANY MCNEIL PLANT & QUARRY	RBLC	KILN NO 3					11/19/2003	1	LB/H	1		THE KILNS ARE CONTROLLED WITH EITHER A CYCLONE/BAGHOUSE COMBO
MT-0012	MT	CONTINENTAL LIME INC.	RLBC	KILN-LIME, TWO	0				11/19/1997	1.25	LB/H EACH KILN	1.25		BAGHOUSE, 75000 ACFM AT 470F WITH APPROX. 17000 SQ.FT AND AN AIR-TO-CLOTH RATIO OF 4:4:1
FL-0224	FL	FLORIDA ROCK INDUSTRIES, INC	RBLC	KILN, PORTLAND CEMENT	14	T/H	COAL	A	12/23/1996	0.11	LB/T	1.54	CLINKER	COMBUSTION CONTROLS.
OK-0110	OK	MUSKOGEE PORCELAIN FLOOR TILE PLT	RLBC	VERTICAL DRYERS				A	10/21/2005	4.26	LB/H	4.26		GOOD COMBUSTION
PA-0241	PA	GRAYMONT BELLEFONTE PLANT	RBLC	# 7 LIME KILN	1050	T/D	COAL/PETROLEUM COKE	D	07/09/2004	0.118	LB/T	5.16	TON OF LIME	
VA-0299	VA	UNITED STATES GYPSUM COMPANY	RLBC	KILN, BOARD DRYING				A	06/19/2006	5.8	LB/H	5.8		
PA-0241	PA	GRAYMONT BELLEFONTE PLANT	RBLC	# 6 LIME KILN	1200	T/D	COAL/PET COKE	D	07/09/2004	0.118	LB/T	5.9	TON OF LIME	
WY-0044	WY	MOUNTAIN CEMENT COMPANY-LARAMIE FACILITY	RLBC	KILN, COAL FIRED	45.3	T/H COAL			03/06/1995	7.3	LB/H	7.3		PROPER COMBUSTION/BURNER DESIGN
OH-0321	OH	MARTIN MARIETTA MATERIALS	RBLC	ROTARY LIME KILN	18000	LB/H	COAL, COKE, NATURAL GAS	B	11/13/2008	39.42	T/YR	9		
IN-0112	IN	LONE STAR INDUSTRIES, INC	RLBC	CEMENT KILN, WET PROCESS, TIRE FUEL	75	T/H	WASTE TIRES	D	09/18/1998	9.13	LB/H	9.13		
FL-0173	FL	SOUTHDOWN, INC.	RBLC	PORTLAND CEMENT, KILN 2	165	T/H		D	06/27/1997	0.09	LB/T	14.85	lb/t per hour kiln feed	GOOD COMBUSTION PRACTICES.
FL-0173	FL	SOUTHDOWN, INC.	RLBC	PORTLAND CEMENT, KILN 1	165	T/H		D	06/27/1997	0.09	LB/T	14.85	lb/t per hour kiln feed	GOOD COMBUSTION PRACTICES
FL-0267	FL	THOMPSON S. BAKER- CEMENT PLANT (FRI	RBLC	IN LINE KILN/RAW MILL WITH ESP AND SNCR			COAL	B	11/05/2004	0.12	LB/T	15	30 DAY	PROCESS CONTROL
FL-0268	FL	BROOKSVILLE CEMENT PLANT (FCS)	RLBC	125 TPH CLINKER KILN AND ASSOCIATED EQUIPM			COAL	B	12/20/2004	0.12	LB/TON CLINKER	15	30 DAY	PROCESS CONTROLS
TX-0282	TX	CAPITOL CEMENT DIVISION	RBLC	WET KILN EXHAUST BAGHOUSE (KS-1B)	378650	T/YR CLINKER	SEE PLANT INFO PAGE	D	09/16/1998	15	LB/H	15		NONE INDICATED.
TX-0355	TX	PORTLAND CEMENT MANUFACTURING PLANT	RLBC	GRINDING/ PREHEATING/ KILN, K-19				D	06/29/2001	15	LB/H	15		NONE INDICATED
FL-0271	FL	BRANFORD CEMENT PLANT (SUWANNEE)	RBLC	KILN W/IN LINE RAW MILL W/ SNCR AND BAGHOU	127	T/H clinker	COAL	B	03/30/2006	0.12	LB/TON CLINKER	15.24	CEMS 30 DAYS BLOCK AVERAGE	GOOD COMBUSTION
OH-0270	OH	CARMEUSE LIME - MAPLE GROVE FACILITY	RLBC	ROTARY KILN (2)	650	T/D	COAL, COKE, NG	A	10/14/2003	16.25	LB/H	16.25	for each kiln	
FL-0231	FL	RINKER/MIAMI CEMENT PLANT	RBLC	IN-LINE KILN/RAW MILL/CLINKER COOLER SYSTE	137	T/H	COAL	D	03/01/2002	0.12	LB/T	16.44	LB/TON CLINKER	PROPER COMBUSTION CONTROL AND RAW MATERIAL SELECTION. REASONABLE ASSURANCE. PLANT IS OPERATING WITHIN VOC LIMIT PROVIDED BY THE MONITOR
FL-0139	FL	SUWANNEE AMERICAN CEMENT COMPANY, INC.	RLBC	IN LINE KILN & RAW MILL	178	T/H	NATURAL GAS	A	06/01/2000	0.12	LB/T	21.36	CLINKER	COMBUSTION CONTROL
AR-0092	AR	ASH GROVE CEMENT COMPANY	RBLC	PH/PC KILN				A	05/15/2007	27.5	LB/H	27.5	30-DAY ROLLING AVERAGE	GOOD COMBUSTION PRACTICES
WI-0250	WI	GRAYMONT (WI) LLC	RLBC	P50 (S50). PREHEATER EQUIPPED, ROTARY LIME K	54	T/H STONE	COAL	A	02/06/2009	33	LB/H	33	USING HIGH ORGANIC CONTENT LIMESTONE	USE OF A PREHEATER KILN AND GOOD OPERATING PRACTICES: GOOD COMBUSTION CONTROL
WV-0022	WV	MARTINSBURG PLANT	RBLC	PRE-HEATER/PRE-CALCINER KILN	5900	T/D	COAL	C	06/02/2005	38.7	LB/H	38.7	3-HOUR AVG.	GOOD COMBUSTION PRACTICES
CO-0048	CO	HOLNAM, LAPORTE CO.	RLBC	CALCINER/ KILN	584000	T/YR	COAL	D	09/22/1998	40	LB/H	40		KILN DESIGNED TO REMOVE KEROGENS FROM RAW MATERIAL. VOC DOES NOT TRIGGER PSD
CO-0047	CO	HOLNAM, FLORENCE	RBLC	KILN/PREHEATER/BYPASS & CLINKER COOLER			COAL	D	07/29/1999	180.5	T/YR	41.21		GOOD COMBUSTION
WY-0036	WY	OCI, WYOMING L.P.-OCI SODA ASH PLANT	RLBC	CALCINER TRONA ORE, NATURAL GAS FIRED	213	T/H ORE FEED RATE	NATURAL GAS		05/27/1997	44.04	LB/H	44.04		
WI-0233	WI	CLM - SUPERIOR	RBLC	LIME KILN (P50)	650	T/D	COAL / PET COKE	A	08/16/2006	84.2	LB/H	84.2	LB CO/H 3 HOUR AVG.	USE OF PREHEATER ROTARY KILN WITH GOOD COMBUSTION CONTROL. COMPLY WITH CO BACT LIMIT FOR COMPLIANCE DEMONSTRATION
TX-0282	TX	CAPITOL CEMENT DIVISION	RLBC	DRY KILN EXHAUST BAGHOUSE (KS-1A)	730000	T/YR CLINKER	SEE PLANT INFO PAGE	D	09/16/1998	97.55	LB/H	97.55		NONE INDICATED.
GA-0134	GA	HOUSTON AMERICAN CEMENT PLANT	RBLC	MAIN KILN STACK ST35	229	T/H OF DRY FEED	COAL	A	06/19/2007	0.5	LB/T CLINKER	114.5	30 DAY ROLLIN AVG BASED ON THC CEMS	JUDICIOUS SELECTION/USE OF RAW MATERIALS.
TX-0466	TX	TEXAS LEHIGH CEMENT	RLBC	KILN EXHAUST (4)					02/03/2003	118.69	LB/H	118.69		BAGHOUSES
GA-0136	GA	CEMEX SOUTHEAST, LLC	RBLC	MAIN KILN STACK K218	270	T/H OF DRY FEED	COAL	B	01/27/2010	0.5	LB/T CLINKER	135	30-DAY ROLLING AVG. BASED ON THE CEMS	JUDICIOUS SELECTION/USE OF RAW MATERIALS
AL-0200	AL	CEMEX, INC.	RLBC	KILN, CEMENT	230	T/H	COAL	D	09/13/2002	136	LB/H	136		
TX-0282	TX	CAPITOL CEMENT DIVISION	RBLC	DRY/WET KILN & ALKALI BYPASS BAGHOUSE		SEE NOTES	SEE PLANT INFORMATIC	D	09/16/1998	277.55	LB/H	277.55		NONE INDICATED
AL-0203	AL	HOLCIM (US), INC.	RLBC	KILN SYSTEM (CALCINING KILN, PREHTR W/PRECA	390	T/H	COAL	D	02/04/2003	2116	T/YR	483.11		
WY-0034	WY	SOLVAY SODA ASH JOINT VENTURE TRONA MINE/SODA ASH	RBLC	CALCINER, NATURAL GAS FIRED TRONA	275	T/H TRONA ORE FEED	NATURAL GAS		02/06/1998	533.5	LB/H	533.5		
TX-0279	TX	NORTH TEXAS CEMENT COMPANY	RLBC	MAIN KILN/SCRUBBER STACK	3100	T/D CLINKER	COAL	A	03/04/1999	686	LB/H	686		GOOD COMBUSTION PRACTICES.
MI-0287	MI	HOLNAM, INC.	RBLC	CEMENT KILNS, WET PROCESS (2)	100	T/H FEED	COAL	D	03/20/2000	13	LB/T	1300		REGENERATIVE THERMAL OXIDIZERS, THREE IN PARALLEL PER KILN. STANDBY ACTIVATED CARBON FOR BACKUP. CURRENT EXISTING LIMITS DO NOT REFLECT ADDITIONAL 80% REMOVAL ANTICIPATED IN RTOS.
MI-0354	MI	HOLNAM, INC	RBLC	CEMENT KILNS, WET PROCESS, (2)	100	T/H	COAL	A	06/23/1998	7217	T/YR	1647.72	combined	COOLING AIR CONDENSER REMOVES PAH AND ORGANICS BEFORE BAGHOUSE. ACTIVATED CARBON IS INJECTED FOR ADSORPTION OF POLLUTANTS. REMOVAL IN BAGHOUSE. CARBON SYSTEM PER PERMIT 60-71H.

1. Permit types: A = New/Greenfield facility, B = Adding new process to an existing facility, C = Modifying an existing process at an existing facility, D = Both B & C.

Table D-6. NOx Best Available Control Technology RBLC Search - Pelletizers

ID	State	Company/Facility	Database	Process Type	Throughput	Throughput Units	Primary Fuel	Permit Type	Permit Date	Emission Limit (lb/hr)	Avg Period	Control Type
	GA	Carbo Cermamics - Toomsboro Plant	TV Permit	Spray Dryers (8)			NG, Propane	B	12/16/2009	8.3	3 hours	Low NOx Burner

1. Permit types: A = New/Greenfield facility, B = Adding new process to an existing facility, C = Modifying an existing process at an existing facility, D = Both B & C.

Table D-7. SO2 Best Available Control Technology RBLC Search - Pelletizers

ID	State	Company/Facility	Database	Process Type	Throughput	Throughput Units	Primary Fuel	Permit Type	Permit Date	Emission Limit (lb/hr)	Control Type
	GA	Carbo Cermamics - Toomsboro Plant	TV Permit	Spray Dryers (8)			NG, Propane	B	12/16/2009	-	Burning of clean fuels

1. Permit types: A = New/Greenfield facility, B = Adding new process to an existing facility, C = Modifying an existing process at an existing facility, D = Both B & C.

Table 8. CO Best Available Control Technology RBLC Search - Pelletizers

ID	State	Company Name	Database	Process Type	Throughput	Throughput Units	Primary Fuel	Permit Type	Permit Date	Emission Limit	Emission Limit Unit	Avg Period	Control Type
OK-0111	OK	DALITALIA LLC	RBLC	SPRAY DRYERS					10/14/2005	0.23	LB/T		GOOD COMBUSTION
OK-0110	OK	DALITALIA LLC	RBLC	SPRAY DRYERS				A	10/21/2005	0.366	LB/TON		GOOD COMBUSTION
	GA	Carbo Cermamics - Toomsboro Plant	TV Permit	Spray Dryers (8)			NG, Propane	B	12/16/2009	16.6	lb/hr	3 hours	Good Combustion

1. Permit types: A = New/Greenfield facility, B = Adding new process to an existing facility, C = Modifying an existing process at an existing facility, D = Both B & C.

Table D-9. PM Best Available Control Technology RBLC Search - Pelletizers

ID	State	Company/Facility	Database	Process Type	Throughput	Throughput Units	Primary Fuel	Permit Type	Permit Date	Emission Limit (gr/dscf)	Avg Period	Control Type
VT-0016	VT	OMYA, INC. / Vermont Marble Power Division	RBLC	FLASH DRYER SYSTEM #1, #2 AND #3				D	10/26/1999	0.01		FABRIC FILTERS
OK-0110	OK	DALITALIA LLC	RBLC	SPRAY DRYERS				A	10/21/2005	0.018		BAGHOUSE
	GA	J.M. Huber Corporation	Issued Title V permit	Spray Dryers						0.02		Baghouse
	GA	Carbo Cermamics - Toomsboro Plant	TV Permit	Spray Dryers (8)			NG, Propane	B	12/16/2009	0.02	3 hours	Baghouse
	GA	Engelhard Corporation-Edgar Plant	Issued Title V permit	Spray Dryer						0.025		Baghouse
OK-0111	OK	DALITALIA LLC	RBLC	VERTICAL DRYERS					10/14/2005	0.76		USE OF NATURAL GAS AS FUEL

1. Permit types: A = New/Greenfield facility, B = Adding new process to an existing facility, C = Modifying an existing process at an existing facility, D = Both B & C.

Table D-10. VOC Best Available Control Technology RBLC Search - Pelletizers

ID	State	Company/Facility	Database	Process Type	Throughput	Throughput Units	Primary Fuel	Permit Type	Permit Date	Emission Limit	Emission Limit Unit	Avg Period	Control Type
OK-0110	OK	DALITALIA LLC	RBLC	VERTICAL				A	10/21/2005	4.26	LB/H		
OK-0111	OK	DALITALIA LLC	RBLC	VERTICAL					10/14/2005	5.11	LB/H		GOOD COMBUSTION
OK-0111	OK	DALITALIA LLC	RBLC	SPRAY DRYERS					10/14/2005	0.25	LB/T		BACT-PSD
OK-0110	OK	DALITALIA LLC	RBLC	SPRAY DRYERS				A	10/21/2005	0.25	LB/TON MATERIAL		GOOD COMBUSTION

1. Permit types: A = New/Greenfield facility, B = Adding new process to an existing facility, C = Modifying an existing process at an existing facility, D = Both B & C.

Table D-11. NO$_X$ Best Available Control Technology RBLC Search - Natural Gas Boilers < 100 MMBtu/hr

ID	State	Company/Facility	Process Type	Throughput	Throughput Units	Primary Fuel	Permit Type	Permit Date	Emission Limit (lb/MMBtu)	Avg. Period	Control Type
LA-0229	LA	SHINTECH PLAQUEMINE PLANT 2	EQT122-EQT125 - FOUR VCM CRACKING FURNACES	90	MMBTU/H	NATURAL GAS	B	7/10/2008	0.009		LOW NOX BURNERS (LNB) IN COMBINATION WITH SELECTIVE CATALYTIC REDUCTION (SCR)
OK-0055	OK	MUSTANG ENERGY PROJECT	AUXILIARY BOILER	31	MMBTU/H	NATURAL GAS	A	2/12/2002	0.01		COMBUSTION CONTROL
NV-0049	NV	HARRAH'S OPERATING COMPANY, INC.	BOILER - UNIT CP26	24	MMBTU/H	NATURAL GAS	A	8/20/2009	0.011		LOW NOX BURNER
MD-0040	MD	CPV ST CHARLES	BOILER	93	MMBTU/H	NATURAL GAS	A	11/12/2008	0.011	3-HR AVERAGE	LOW NOX WITH FGR
NY-0095	NY	CAITHNES BELLPORT ENERGY CENTER	AUXILIARY BOILER	29.4	MMBTU/H	NATURAL GAS	0	5/10/2006	0.011		LOW NOX BURNERS & FLUE GAS RECIRCULATION
CA-0903	CA	DISNEYLAND RESORT	BOILER, CLEAVER BROOKS WATER-TUBE	8.5	MMBTU/H	NATURAL GAS	A	9/27/2001	0.015		ALZETA ULTRA LOW-NOX BURNER, GOOD COMBUSTION
TX-0378	TX	LA PORTE POLYPROPYLENE PLANT	PACKAGE BOILER BO-4	60	MMBTU/H	NAT GAS	D	11/5/2001	0.015		ULTRA LOW-NOX BURNERS
LA-0240	LA	FLOPAM INC.	Boilers	25.1	MMBTU/H	natural gas	A	6/14/2010	0.015	HOURLY MAXIMUM	Ultra Low NOx Burners
NV-0050	NV	MGM MIRAGE	WATER HEATERS - UNITS NY037 AND NY038 AT NEW YORK - NEW YORK	2	MMBTU/H	NATURAL GAS	A	11/30/2009	0.025		LOW-NOX BURNERS AND GOOD COMBUSTION PRACTICES
AZ-0049	AZ	LA PAZ GENERATING FACILITY	AUXILIARY BOILER FOR GE TURBINE	41	MMBTU/H	NATURAL GAS	A	9/4/2003	0.027		LOW NOX BURNERS
NV-0047	NV	NELLIS AIR FORCE BASE	BOILERS/HEATERS - NATURAL GAS-FIRED	0	0	NATURAL GAS	A	2/26/2008	0.03		LOW-NOX BURNER AND FLUE GAS RECIRCULATION
NV-0049	NV	HARRAH'S OPERATING COMPANY, INC.	BOILER - UNIT BA01	16.8	MMBTU/H	NATURAL GAS	A	3/18/2009	0.03		LOW-NOX BURNER AND BLUE GAS RECIRCULATION
WY-0067	WY	ECHO SPRINGS GAS PLANT	HOT OIL HEATER S38	84	MMBTU/H	NATURAL GAS	A	5/29/2008	0.03		LOW NOX BURNERS WITH FLUE GAS RECIRCULATION
NV-0049	NV	HARRAH'S OPERATING COMPANY, INC.	BOILER - UNIT BA03	31.38	MMBTU/H	NATURAL GAS	A	3/18/2009	0.031		LOW-NOX BURNER
OH-0258	OH	PRO TEC COATING COMPANY	BOILERS (4)	20.9	MMBTU/H	NATURAL GAS	D	4/1/2000	0.033		LOW NOX BURNERS.
IA-0060	IA	HAWKEYE GENERATING, LLC	AUXILIARY BOILER (48.5 MMBTU/H)	48.69	IILLION CF/Y	NATUAL GAS	A	11/16/2001	0.034		GCP
OH-0263	OH	FREMONT ENERGY CENTER, LLC	AUXILIARY BOILER	80	MMBTU/H	NATURAL GAS	A	4/6/2001	0.034		LOW NOX BURNERS
OH-0252	OH	DUKE ENERGY HANGING ROCK ENERGY	BOILERS (2)	30.6	MMBTU/H	NATURAL GAS	A	3/1/2001	0.035	EACH BOILER	
AL-0191	AL	HYUNDAI MOTOR MANUFACTURING OF ALABAMA, LLC	BOILERS, NATURAL GAS, (3)	50	MMBTU/H	NATURAL GAS	A	3/23/2004	0.035		NATURAL GAS ONLY; LOW NOX BURNERS
AL-0178	AL	ANNISTON ARMY DEPOT	TWO (2) 13.4 MMBTU/H BOILERS	13.4	MMBTU/H	NATURAL GAS	A	1/5/2001	0.036		LOW NOX BURNERS
AL-0178	AL	ANNISTON ARMY DEPOT	TWO (2) 11.7 MMBTU/H BOILERS	11.7	MMBTU/H	NATURAL GAS	A	1/5/2001	0.036		LOW NOX BURNERS
AZ-0049	AZ	LA PAZ GENERATING FACILITY	AUXILIARY BOILER FOR SIEMENS TURBINES	55.34	MMBTU/H	NATURAL GAS	A	9/4/2003	0.036		LOW NOX BURNERS
NV-0049	NV	HARRAH'S OPERATING COMPANY, INC.	BOILER - UNIT CP03	33.48	MMBTU/H	NATURAL GAS	A	8/20/2009	0.037		LOW NOX BURNER
NJ-0062	NJ	CONSOLIDATE EDISON DEVELOPMENT (	FUEL GAS HEATERS (3 UNITS)	4.62	MMBTU/H	NATURAL GAS	A	10/22/2002	0.037		LOW NOX -COMBUSTOR
GA-0101	GA	MURRAY ENERGY FACILITY	BOILER, AUXILIARY	31.4	MMBTU/H	NATURAL GAS	D	10/23/2002	0.037		DRY LOW NOX BURNERS, FLUE GAS RECIRCULATION
WA-0297	WA	NORTHWEST PIPELINE CORPORATION M	BOILER	4.19	MMBTU/H	NATURAL GAS	D	8/30/2002	0.040	24 H AVG	GOOD COMBUSTION PRACTICE
MN-0053	MN	FAIRBAULT ENERGY PARK	BOILER, NATURAL GAS (1)	40	MMBTU/H	NATURAL GAS	A	7/15/2004	0.04	3 HOUR AVERAGE	LOW NOX BURNER; FGR.
IA-0088	IA	ADM CORN PROCESSING - CEDAR RAPID	INDIRECT-FIRED DDGS DRYER	93.7	MMBTU/H	NATURAL GAS	B	6/29/2007	0.04	AVERAGE OF 3 TEST RUNS	LOW NOX BURNERS WITH FLUE GAS RECIRCULATION
OK-0135	OK	PRYOR PLANT CHEMICAL	BOILERS #1 AND #2	80	MMBTU/H	NATURAL GAS	C	2/23/2009	0.05	3-H/168-H ROLLING CUMMULATIVE	LOW-NOX BURNERS AND GOOD COMBUSTION PRACTICES
AL-0169	AL	BLOUNT MEGAWATT FACILITY	AUXILIARY BOILER	40	MMBTU/H	NATURAL GAS	A	2/5/2001	0.08		LOW NOX BURNERS
OK-0074	OK	KIAMICHI ENERGY FACILITY	AUXILIARY BOILER	27.5	MMBTU/H	NATURAL GAS	D	5/1/2001	0.1		LOW NOX BURNERS
WA-0301	WA	BP CHERRY POINT REFINERY	PROCESS HEATER, IHT	13	MMBTU/H	NATURAL GAS	B	4/20/2005	0.1	7% O2, 24 hr ave	ULTRA LOW NOX BURNERS
NV-0046	NV	GOODSPRINGS COMPRESSOR STATION	COMMERCIAL/INSTITUTIONAL BOILER	3.85	MMBTU/H	NATURAL GAS	A	5/16/2006	0.101		GOOD COMBUSTION PRACTICE
TX-0389	TX	BAYTOWN CARBON BLACK PLANT	BACK-UP BOILER	13.4	MMBUT/H	NATURAL GAS	A	12/31/2002	0.104		
AL-0181	AL	DUKE ENERGY AUTAUGA, LLC	31.4 MMBTU/HR NATURAL GAS FIRED BOILER	31.4	MMBTU/H	NATURAL GAS	A	10/23/2001	0.108		LOW NOX BURNERS
AL-0230	AL	THYSSENKRUPP STEEL AND STAINLESS	NATURAL GAS-FIRED BATCH ANNEALING FU	33.4	MMBTU each	NATURAL GAS	A	8/17/2007	0.11		UNLB WITH EGR
GA-0107	GA	TALBOT ENERGY FACILITY	FUEL GAS PREHEATERS, (3)	5	MMBTU/H	NATURAL GAS	A	6/9/2003	0.11		DRY LOW NOX BURNERS
LA-0231	LA	LAKE CHARLES GASIFICATION FACILITY	GASIFIER STARTUP PREHEATER BURNERS (5)	35	MMBTU/H	NATURAL GAS	A	6/22/2009	0.11	MAXIMUM (EACH)	GOOD DESIGN AND PROPER OPERATION
TX-0364	TX	SALT CREEK GAS PLANT	GLYCOL REBOILER, EPN11	2.5	MMBTU/H	NAT GAS	D	1/31/2003	0.116		NONE INDICATED
TX-0364	TX	SALT CREEK GAS PLANT	HOT OIL HEATER, EPN6	12	MMBTU/H	NAT GAS	D	1/31/2003	0.118		NONE INDICATED
LA-0203	LA	OAKDALE OSB PLANT	AUXILIARY THERMAL OIL HEATER	66.5	MMBTU/H	NATURAL GAS	A	6/13/2005	0.118	HOURLY MAXIMUM	USE OF NATURAL GAS AS FUEL AND GOOD COMBUSTION PRACTICES
NV-0039	NV	CHUCK LENZIE GENERATING STATION	AUXILIARY BOILERS	44.1	MMBTU/H	NATURAL GAS	A	6/1/2001	0.118	ONE-HOUR AVERAGE	GOOD COMBUSTION CONTROL
MS-0045	MS	NISSAN NORTH AMERICA, INC.	BOILER	35	MMBTU	NATURAL GAS	A	4/2/2001	0.12		LOW NOX BURNERS
AR-0076	AR	U.S. ARMY, PINE BLUFF ARSENAL	BOILER, LABORATORY SN-PBCDF-16	1.4	mmbtu/h	NATURAL GAS	D	2/17/2004	0.143		LOW-NOX BURNERS WITHOUT FLUE GAS RECIRCULATION.
NE-0026	NE	NUCOR STEEL DIVISION	NNII BILET POST-HEATER	6.8	MMBTU/H	NATURAL GAS	A	6/22/2004	0.147		ULTRA-LOW NOX BURNERS
IA-0064	IA	ROQUETTE AMERICA	DEW POINT HEATER	1.6	MMBTU/H	NATURAL GAS	A	1/31/2003	0.15		GOOD COMBUSTION PRACTICES
OK-0044	OK	SMITH POCOLA ENERGY PROJECT	AUXILIARY BOILERS, (2)	48	MMBTU/H	NATURAL GAS	A	8/16/2001	0.196	combined	DRY LOW NOX BURNERS, OPERATES IN PRE-MIX MODE.
LA-0174	LA	PORT HUDSON OPERATIONS	POWER BOILER NO. 2	65.5	MMBTU/H	NAT GAS	D	1/25/2002	0.936		LOW-NOX BURNERS

Table D-12. SO_2 Best Available Control Technology RBLC Search - Natural Gas Boilers < 100 MMBtu/hr

ID	State	Company/Facility	Process Type	Throughput	Throughput Units	Primary Fuel	Permit Type	Permit Date	Emission Limit (lb/MMBtu)	Avg. Period	Control Type
OH-0309	OH	TOLEDO SUPPLIER PARK- PAINT SHOP	BOILER (2), NATURAL GAS	20.4	MMBTU/H	NATURAL GAS	C	5/3/2007	0.00049		
AL-0190	AL	GE PLASTICS	FURNACE, HOT OIL, 20 MMBTU/H	20	MMBTU/H	NATURAL GAS	D	7/13/2001	0.00050		GOOD COMBUSTION PRACTICES
NY-0095	NY	CAITHNES BELLPORT ENERGY CENTER	AUXILIARY BOILER	29.4	MMBTU/H	NATURAL GAS	0	5/10/2006	0.00050		LOW SULFUR FUEL
LA-0231	LA	LAKE CHARLES GASIFICATION FACILITY	METHANATION STARTUP HEATERS	56.9	MMBTU/H	NATURAL GAS	A	6/22/2009	0.00053	MAXIMUM	FUELED BY NATURAL GAS OR SUBSTITUTE NATURAL GAS (SNG)
WI-0228	WI	WPS - WESTON PLANT	B63, S63; B64, S64 - NATURAL GAS STATION HEATER 1 AND 2	0.75	MMBTU/H	NATURAL GAS	A	10/19/2004	0.00053		NATURAL GAS
TX-0501	TX	TEXSTAR GAS PROCESS FACILITY	POWER STEAM BOILER	93	MMBTU/H	NATURAL GAS	B	7/11/2006	0.00054		
OH-0251	OH	CENTRAL SOYA COMPANY INC.	DRYER, SOY PROTEIN CONCENTRATE - COMBUSTION	37	MMBTU/H	NATURAL GAS	D	11/29/2001	0.00057		
LA-0231	LA	LAKE CHARLES GASIFICATION FACILITY	GASIFIER STARTUP PREHEATER BURNERS (5)	35	MMBTU/H	NATURAL GAS	A	6/22/2009	0.00057	MAXIMUM (EACH)	FUELED BY NATURAL GAS OR SUBSTITUTE NATURAL GAS (SNG)
LA-0231	LA	LAKE CHARLES GASIFICATION FACILITY	SHIFT REACTOR STARTUP HEATER	34.2	MMBTU/H	NATURAL GAS	A	6/22/2009	0.00058	MAXIMUM	FUELED BY NATURAL GAS OR SUBSTITUTE NATURAL GAS (SNG)
OH-0255	OH	AEP WATERFORD ENERGY LLC	BOILER, NATURAL GAS	85.2	MMBTU/H	NATURAL GAS	D	3/29/2001	0.00059		LOW S NATURAL GAS, 2 GR/100 SCF
AL-0230	AL	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	NATURAL GAS-FIRED BATCH ANNEALING FURNACES (LA63, LA64)	33.4	MMBTU each	NATURAL GAS	A	8/17/2007	0.0006		
AR-0077	AR	BLUEWATER PROJECT	BOILERS	22	MMBTU/H	NATURAL GAS	A	7/22/2004	0.0006		NATURAL GAS COMBUSTION ONLY
IA-0062	IA	EMERY GENERATING STATION	GAS HEATER, (2)	16.4	MMBTU/H	NATURAL GAS	A	12/20/2002	0.0006		LOW SULFUR FUEL, NG
IN-0108	IN	NUCOR STEEL	BOILER, NATURAL GAS, (2)	34	MMBTU/H	NATURAL GAS	D	11/21/2003	0.0006		COMPLIANCE BY USING NATURAL GAS
TX-0364	TX	SALT CREEK GAS PLANT	HOT OIL HEATER, EPN26	32.5	MMBTU/H	NAT GAS	D	1/31/2003	0.00062		NONE INDICATED
WI-0227	WI	PORT WASHINGTON GENERATING STATION	NATURAL GAS FIRED AUXILLIARY BOILER	97.1	MMBTU/H	NATURAL GAS	A	10/13/2004	0.00062		NATURAL GAS FUEL
TX-0354	TX	ATOFINA CHEMICALS INCORPORATED	(2) STEAM BOILERS, X-426A AND X-426B	15.8	MMBTU/H	NATURAL GAS	D	12/19/2002	0.00063	EACH	FUEL GAS SHALL BE SWEET NATURAL GAS CONTAINING NO MORE THAN 5 GR S/100 DSCF.
TX-0354	TX	ATOFINA CHEMICALS INCORPORATED	HEAT TRANSFER FLUID HEATER, H202	31	MMBTU/H	NATURAL GAS	D	12/19/2002	0.00065		FUEL GAS SHALL BE SWEET NATURAL GAS CONTAINING NO MORE THAN 5 GR S/100 DSCF.
TX-0354	TX	ATOFINA CHEMICALS INCORPORATED	HEAT TRANSFER FLUID HEATER, H2202	31	MMBTU/H	NATURAL GAS	D	12/19/2002	0.00065		FUEL GAS SHALL BE SWEET NATURAL GAS CONTAINING NO MORE THAN 0.5 GR S/100 DSCF.
NV-0037	NV	COPPER MOUNTAIN POWER	AUXILIARY BOILER	60	MMBTU/H	NATURAL GAS	A	5/14/2004	0.0007		USE OF LOW-SULFUR NATURAL GAS
LA-0203	LA	OAKDALE OSB PLANT	AUXILIARY THERMAL OIL HEATER	66.5	MMBTU/H	NATURAL GAS	A	6/13/2005	0.0008	HOURLY MAXIMUM	USE OF NATURAL GAS AS FUEL AND GOOD COMBUSTION PRACTICES
TX-0364	TX	SALT CREEK GAS PLANT	HOT OIL HEATER, EPN6	12	MMBTU/H	NAT GAS	D	1/31/2003	0.00083		NONE INDICATED
OK-0129	OK	CHOUTEAU POWER PLANT	AUXILIARY BOILER	33.5	MMBTU/H	NATURAL GAS	B	1/23/2009	0.0009		LOW SULFUR FUEL
NV-0044	NV	HARRAH'S OPERATING COMPANY, INC.	COMMERCIAL/INSTITUTIONAL-SIZE BOILERS	35.4	MMBTU/H	NATURAL GAS	A	1/4/2007	0.001		USE OF NATURAL GAS AS THE ONLY FUEL
VA-0255	VA	VA POWER - POSSUM POINT	BOILER, AUXILIARY	99	MMBTU/H	NATURAL GAS	D	11/18/2002	0.001	EACH UNIT	LOW SULFUR FUEL AND GOOD COMBUSTION PRACTICES.
OH-0252	OH	DUKE ENERGY HANGING ROCK ENERGY FACILITY	BOILERS (2)	30.6	MMBTU/H	NATURAL GAS	A	12/28/2004	0.001	EACH BOILER	THE MAXIMUM S CONTENT OF THE NATURAL GAS SHALL NOT EXCEED 2 GRAINS PER 100 CUBIC FEET.
WI-0226	WI	WPS - WESTON PLANT	NATURAL GAS FIRED BOILER	46.2	MMBTU/H	NATURAL GAS	A	8/27/2004	0.0011		NATURAL GAS FUEL ONLY
NV-0047	NV	NELLIS AIR FORCE BASE	BOILERS/HEATERS - NATURAL GAS-FIRED	0	0	NATURAL GAS	A	2/26/2008	0.0015		USE OF PIPELINE-QUALITY NATURAL GAS
NV-0048	NV	GOODSPRINGS COMPRESSOR STATION	COMMERCIAL/INSTITUTIONAL-SIZE BOILER (<100 MMBTU/H)	3.85	MMBTU/H	NATURAL GAS	A	5/16/2006	0.0015		LOW-SULFUR NATURAL GAS IS THE ONLY FUEL USED BY THE UNIT.
*OK-0134	OK	PRYOR PLANT CHEMICAL	Nitric Acid Preheaters No. 1 (EU 401, EUG 4)	20	MMBTUH	Natural Gas	C	2/23/2009	0.0015		natural gas combustion
OH-0264	OH	NORTON ENERGY STORAGE, LLC	RECUPERATOR PRE-HEATERS (9)	12.84	MMBTU/H	NATURAL GAS	D	5/23/2002	0.0018		THE MAXIMUM SULFUR CONTENT OF THE NATURAL GAS SHALL NOT EXCEED 0.6 GRAINS PER 100 STANDARD CUBIC FEET.
OH-0264	OH	NORTON ENERGY STORAGE, LLC	FUEL SUPPLY HEATERS (9)	11.45	MMBTU/H	NATURAL GAS	D	5/23/2002	0.0018		THE MAXIMUM SULFUR CONTENT OF THE NATURAL GAS SHALL NOT EXCEED 0.6 GRAINS PER 100 STANDARD CUBIC FEET.
AR-0086	AR	NUCOR-YAMATO STEEL COMPANY, BLYTHEVILLE MILL	VTD BOILER	50	MMBTU/H	NATURAL GAS	A	6/11/2004	0.002		GOOD COMBUSTION PRACTICE, NATURAL GAS COMBUSTION
WI-0227	WI	PORT WASHINGTON GENERATING STATION	GAS HEATER (P06, S06)	10	MMBTU/H	NATURAL GAS	A	10/13/2004	0.0020		NATURAL GAS FUEL
OK-0135	OK	PRYOR PLANT CHEMICAL	BOILERS #1 AND #2	80	MMBTU/H	NATURAL GAS	C	2/23/2009	0.0025		
NV-0046	NV	GOODSPRINGS COMPRESSOR STATION	COMMERCIAL/INSTITUTIONAL BOILER	3.85	MMBTU/H	NATURAL GAS	A	5/16/2006	0.0026		LOW-SULFUR NATURAL GAS IS THE ONLY FUEL FOR THE PROCESS.
NJ-0062	NJ	CONSOLIDATE EDISON DEVELOPMENT (CED)	FUEL GAS HEATERS (3 UNITS)	4.62	MMBTU/H	NATURAL GAS	A	10/22/2002	0.0030		LOW SULFUR FUEL.
TX-0364	TX	SALT CREEK GAS PLANT	HP TEG FIREBOX, EPN30	3	MMBTU/H	NAT GAS	D	1/31/2003	0.0033		NONE INDICATED
LA-0174	LA	PORT HUDSON OPERATIONS	POWER BOILER NO. 2	65.5	MMBTU/H	NAT GAS	D	1/25/2002	0.0040		FIRING NATURAL GAS
NV-0049	NV	HARRAH'S OPERATING COMPANY, INC.	BOILER - UNIT BA01	16.8	MMBTU/H	NATURAL GAS	A	8/20/2009	0.0042		FUEL IS LIMITED TO NATURAL GAS.
NJ-0036	NJ	AES RED OAK LLC	FUEL GAS HEATER	16	MMBTU/H	NATURAL GAS	D	10/24/2001	0.0043		NATURAL GAS FUEL
OH-0248	OH	LAWRENCE ENERGY	BOILER	99	MMBTU/H	NATURAL GAS	A	9/24/2002	0.0057		
OK-0090	OK	DUKE ENERGY STEPHENS, LLC STEPHENS ENERGY	BOILER, AUXILIARY	33	MMBTU/H	NATURAL GAS	D	3/21/2003	0.0061		BACT IS USE OF PIPE-LINE QUALITY NATURAL GAS
AR-0090	AR	NUCOR STEEL, ARKANSAS	PICKLE LINE BOILERS, SN-52	12.6	MMBTU EACH	NATURAL GAS	A	4/3/2006	0.0079		
TX-0364	TX	SALT CREEK GAS PLANT	GLYCOL REBOILER, EPN11	2.5	MMBTU/H	NAT GAS	D	1/31/2003	0.008		NONE INDICATED
TX-0458	TX	JACK COUNTY POWER PLANT	AUXILIARY BOILER	36	mmbtu/h	NATURAL GAS	0	7/22/2003	0.0083		
VA-0243	VA	STANLEY FURNITURE	BOILER, NAT GAS & OIL	26.5	MMBTU/H	NATURAL GAS	A	12/1/2002	0.1378		EMISSION LIMITS IN T/YR ONLY
KY-0087	KY	QUEBECOR WORLD FRANKLIN	BOILER, NATURAL GAS, #4	33.5	MMBTU/H	NATURAL GAS	D	7/12/2002	1.057		CLEAN FUEL: FUEL OIL LIMITED TO < 0.5% S BY WT

Table D-13. CO Best Available Control Technology RBLC Search - Natural Gas Boilers < 100 MMBtu/hr

ID	State	Company/Facility	Process Type	Throughput	Throughput Units	Primary Fuel	Permit Type	Permit Date	Emission Limit (lb/MMBtu)	Avg. Period	Control Type
NV-0049	NV	HARRAH'S OPERATING COMPANY, INC.	BOILER - UNIT CP01	35.4	MMBTU/H	NATURAL GAS	A	8/20/2009	0.0073		OPERATING IN ACCORDANCE WITH THE MANUFACTURER'S SPECIFICATION
NV-0049	NV	HARRAH'S OPERATING COMPANY, INC.	BOILER - UNIT CP03	33.48	MMBTU/H	NATURAL GAS	A	8/20/2009	0.0075		OPERATING IN ACCORDANCE WITH THE MANUFACTURER'S SPECIFICATION
NE-0026	NE	NUCOR STEEL DIVISION	NNII BILET POST-HEATER	6.8	MMBTU/H	NATURAL GAS	A	6/22/2004	0.0084		
OH-0258	OH	PRO TEC COATING COMPANY	BOILERS (4)	20.9	MMBTU/H	NATURAL GAS	D	2/15/2001	0.0110	each	
IA-0062	IA	EMERY GENERATING STATION	AUXILIARY BOILER	68	MMBTU/H	NATURAL GAS	A	12/20/2002	0.0164		CATALYTIC OXIDATION
NV-0049	NV	HARRAH'S OPERATING COMPANY, INC.	BOILER - UNIT BA03	31.38	MMBTU/H	NATURAL GAS	A	8/20/2009	0.0172		OPERATING IN ACCORDANCE WITH THE MANUFACTURER'S SPECIFICATION.
NV-0049	NV	HARRAH'S OPERATING COMPANY, INC.	BOILER - UNIT BA01	16.8	MMBTU/H	NATURAL GAS	A	8/20/2009	0.0173		FLUE GAS RECIRCULATION
MD-0040	MD	CPV ST CHARLES	BOILER	93	MMBTU/H	NATURAL GAS	A	11/12/2008	0.02	3-HR AVERAGE	
WY-0067	WY	ECHO SPRINGS GAS PLANT	HOT OIL HEATER S38	84	MMBTU/H	NATURAL GAS	A	4/1/2009	0.02		GOOD COMBUSTION PRACTICES
NV-0050	NV	MGM MIRAGE	WATER HEATERS - UNITS NY037 AND NY038 AT NEW YORK - NEW YORK	2	MMBTU/H	NATURAL GAS	A	11/30/2009	0.035		LIMITING THE FUEL TO NATURAL GAS ONLY AND GOOD COMBUSTION PRACTICES
NV-0044	NV	HARRAH'S OPERATING COMPANY, INC.	COMMERCIAL/INSTITUTIONAL-SIZE BOILERS	35.4	MMBTU/H	NATURAL GAS	A	1/4/2007	0.036		GOOD COMBUSTION DESIGN
NY-0095	NY	CAITHNES BELLPORT ENERGY	AUXILIARY BOILER	29.4	MMBTU/H	NATURAL GAS		5/10/2006	0.036		GOOD COMBUSTION PRACTICES
NV-0047	NV	NELLIS AIR FORCE BASE	BOILERS/HEATERS - NATURAL GAS-FIRED			NATURAL GAS	A	2/26/2008	0.037		FLUE GAS RECIRCULATION
NV-0049	NV	HARRAH'S OPERATING COMPANY, INC.	BOILER - UNIT CP26	24	MMBTU/H	NATURAL GAS	A	8/20/2009	0.037		OPERATING IN ACCORDANCE WITH THE MANUFACTURER'S SPECIFICATION
LA-0240	LA	FLOPAM INC.	Boilers	25.1	MMBTU/H	natural gas	A	6/14/2010	0.0371	HOURLY MAXIMUM	Good equipment design and proper combustion practices
TX-0458	TX	JACK COUNTY POWER PLANT	AUXILIARY BOILER	36	mmbtu/h	NATURAL GAS		7/22/2003	0.0389		
OK-0054	OK	QUAD GRAPHICS OKC FACILITY	BOILERS	62.77	MMBTU/H	NATURAL GAS	A	8/21/2001	0.0393		GOOD COMBUSTION/MAINTENANCE
OK-0136	OK	PONCA CITY REFINERY	TB-1, TB-2, TB-3	95	MMBTU/H	NATURAL GAS	D	2/9/2009	0.04	365-DAY ROLLING AVERAGE	ULTRA-LOW NOX BURNERS AND GOOD COMBUSTION PRACTICE; 0.04 LB/MMBTU
LA-0229	LA	SHINTECH PLAQUEMINE PLANT 2	EQT122-EQT125 - FOUR VCM CRACKING FURNACES	90	MMBTU/H	NATURAL GAS	B	7/10/2008	0.046		GOOD COMBUSTION PRACTICES
WI-0227	WI	PORT WASHINGTON GENERATING STATION	GAS HEATER (P06, S06)	10	MMBTU/H	NATURAL GAS	A	10/13/2004	0.047		NATURAL GAS FUEL
NJ-0036	NJ	AES RED OAK LLC	FUEL GAS HEATER	16	MMBTU/H	NATURAL GAS	D	10/24/2001	0.0538		GOOD COMBUSTION PRACTICE
LA-0231	LA	LAKE CHARLES GASIFICATION FACILITY	GASIFIER STARTUP PREHEATER BURNERS (5)	35	MMBTU/H	NATURAL GAS	A	6/22/2009	0.056	MAXIMUM (EACH)	GOOD DESIGN AND PROPER OPERATION
MN-0054	MN	MANKATO ENERGY CENTER	BOILER, COMMERCIAL	70	MMBTU/H	NATURAL GAS		12/4/2003	0.06		GOOD COMBUSTION
IN-0108	IN	NUCOR STEEL	BOILER, NATURAL GAS, (2)	34	MMBTU/H	NATURAL GAS	D	11/21/2003	0.061		GOOD COMBUSTION PRACTICES, NATURAL GAS
OK-0072	OK	REDBUD POWER PLT	AUXILIARY BOILER	93	MMBUT/H	NATURAL GAS	D	5/6/2002	0.07		BOILER DESIGN AND GOOD OPERATING PRACTICES
TX-0501	TX	TEXSTAR GAS PROCESS FACILITY	POWER STEAM BOILER	93	MMBTU/H	NATURAL GAS	B	7/11/2006	0.0758		
WY-0066	WY	MEDICINE BOW IGL PLANT	GASIFICATION PREHEATER 1	21	MMBTU/H	NATURAL GAS	A	3/4/2009	0.08	HOURLY	GOOD COMBUSTION PRACTICES
VA-0261	VA	CPV CUNNINGHAM CREEK	AUXILIARY BOILER	80	MMBTU/H	NATURAL GAS	A	9/6/2002	0.0803		GOOD COMBUSTION PRACTICES.
TX-0378	TX	LA PORTE POLYPROPYLENE PLANT	PACKAGE BOILER BO-4	60	MMBTU/H	NAT GAS	D	11/5/2001	0.0807		NONE INDICATED
LA-0120	LA	GEISMAR PLANT	HOT OIL FURNACE, #621-99	20	MMBTU/H	NATURAL GAS	D	2/26/2002	0.081		GOOD COMBUSTION PRACTICES
OH-0323	OH	TITAN TIRE CORPORATION OF BRYAN	BOILER	50.4	MMBTU/H	NATURAL GAS		6/5/2008	0.0823		
NC-0094	NC	GENPOWER EARLEYS, LLC	BOILER, AUXILIARY, NATURAL GAS	83	MMBTU/H	NATURAL GAS	A	1/9/2002	0.0824		GOOD C OMBUSTION PRACTICES AND DESIGN
LA-0231	LA	LAKE CHARLES GASIFICATION FACILITY	METHANATION STARTUP HEATERS	56.9	MMBTU/H	NATURAL GAS	A	6/22/2009	0.0824	MAXIMUM	GOOD DESIGN AND PROPER OPERATION
LA-0231	LA	LAKE CHARLES GASIFICATION FACILITY	SHIFT REACTOR STARTUP HEATER	34.2	MMBTU/H	NATURAL GAS	A	6/22/2009	0.0825	MAXIMUM	GOOD DESIGN AND PROPER OPERATION
*OK-0134	OK	PRYOR PLANT CHEMICAL	Nitric Acid Preheaters No. 1 (EU 401, EUG 4)	20	MMBTUH	Natural Gas	C	2/23/2009	0.0825	1-HR, 8-HR	good combustion practices
*OK-0134	OK	PRYOR PLANT CHEMICAL	Nitric Acid Preheater No3 (EU 402, EUG 4)	20	mmbtuh	Natural Gas	C	2/23/2009	0.0825	1-HR/8-HR	good combustion
AL-0231	AL	NUCOR DECATUR LLC	GALVANIZING LINE FURNACE	98.7	MMBTU/H	NATURAL GAS	D	6/12/2007	0.084		
OK-0128	OK	MID AMERICAN STEEL ROLLING MILL	Ladle pre-heater and refractory drying			natural gas	B	9/8/2008	0.084		natural gas fuel
GA-0098	GA	RINCON POWER PLANT	AUXILIARY BOILER	83	MMBTU/H	NATURAL GAS	A	3/24/2003	0.093		
OK-0129	OK	CHOUTEAU POWER PLANT	AUXILIARY BOILER	33.5	MMBTU/H	NATURAL GAS	B	1/23/2009	0.15		GOOD COMBUSTION
AK-0062	AK	BADAMI DEVELOPMENT FACILITY	NATCO TEG REBOILER	1.34	MMBTU/H	NATURAL GAS	D	8/19/2005	0.15		GOOD OPERATIONAL PRACTICES
AR-0090	AR	NUCOR STEEL, ARKANSAS	PICKLE LINE BOILERS, SN-52	12.6	MMBTU EACH	NATURAL GAS	A	4/3/2006	0.254		GOOD COMBUSTION PRACTICE
PA-0210	PA	DART CONTAINER CORP OF PA	BOILER, (2)	33.5	MMBTU/H	NATURAL GAS	A	12/14/2001	0.30		GOOD COMBUSTION PRACTICE
OK-0071	OK	MCCLAIN ENERGY FACILITY	AUXILIARY BOILER	22	MMBTU/H	NATURAL GAS	D	10/25/2001	0.37		USE OF NATURAL GAS FUEL
AR-0077	AR	BLUEWATER PROJECT	BOILERS	22	MMBTU/H	NATURAL GAS	A	7/22/2004	0.84		GOOD COMBUSTION PRACTICE

Table D-14. PM Best Available Control Technology RBLC Search - Natural Gas Boilers < 100 MMBtu/hr

ID	State	Company/Facility	Process Type	Throughput	Throughput Units	Primary Fuel	Permit Type	Permit Date	Emission Limit lb/MMBtu	Avg. Period	Control Type
LA-0231	LA	LAKE CHARLES GASIFICATION FACILITY	GASIFIER STARTUP PREHEATER BURNERS (5)	35	MMBTU/H	NATURAL GAS	A	6/22/2009	0.0009	MAXIMUM (EACH)	GOOD DESIGN AND PROPER OPERATION
MD-0035	MD	DOMINION	VAPORIZATION HEATER			NATURAL GAS	A	8/12/2005	0.001		
OH-0323	OH	TITAN TIRE CORPORATION OF BRYAN	BOILER	50.4	MMBTU/H	NATURAL GAS		6/5/2008	0.0019		
OH-0309	OH	TOLEDO SUPPLIER PARK- PAINT SHOP	BOILER (2), NATURAL GAS	20.4	MMBTU/H	NATURAL GAS	C	5/3/2007	0.002		
OH-0251	OH	CENTRAL SOYA COMPANY INC.	DRYER, SOY PROTEIN CONCENTRATE - COMBUSTION	37	MMBTU/H	NATURAL GAS	D	11/29/2001	0.003		BAGHOUSE WITH 100% CAPTURE
NY-0095	NY	CAITHNES BELLPORT ENERGY CENTER	AUXILIARY BOILER	29.4	MMBTU/H	NATURAL GAS		5/10/2006	0.0033		LOW SULFUR FUEL
LA-0240	LA	FLOPAM INC.	Boilers	25.1	MMBTU/H	natural gas	A	6/14/2010	0.004	HOURLY MAXIMUM	Good equipment design and proper combustion practices, fueled by natural gas/alcohol
MD-0040	MD	CPV ST CHARLES	BOILER	93	MMBTU/H	NATURAL GAS	A	11/12/2008	0.005	3-HR AVERAGE	
MD-0040	MD	CPV ST CHARLES	BOILER	93	MMBTU/H	NATURAL GAS	A	11/12/2008	0.005	3-HR AVERAGE	
MD-0040	MD	CPV ST CHARLES	BOILER	93	MMBTU/H	NATURAL GAS	A	11/12/2008	0.005	3-HR AVERAGE	
LA-0240	LA	FLOPAM INC.	Boilers	25.1	MMBTU/H	natural gas	A	6/14/2010	0.0052	HOURLY MAXIMUM	Good equipment design and proper combustion practices, fueled by natural gas/alcohol
LA-0120	LA	GEISMAR PLANT	REGENERATOR FURNACE #620-99	3.3	MMBTU/H	NATURAL GAS	D	2/26/2002	0.0061		GOOD COMBUSTION PRACTICES
OK-0135	OK	PRYOR PLANT CHEMICAL	BOILERS #1 AND #2	80	MMBTU/H	NATURAL GAS	C	2/23/2009	0.0063	24-HOUR	
TX-0364	TX	SALT CREEK GAS PLANT	HP TEG FIREBOX, EPN30	3	MMBTU/H	NAT GAS	D	1/31/2003	0.0067		NONE INDICATED
TX-0501	TX	TEXSTAR GAS PROCESS FACILITY	POWER STEAM BOILER	93	MMBTU/H	NATURAL GAS	B	7/11/2006	0.0069		
MD-0040	MD	CPV ST CHARLES	HEATER	1.7	MMBTU/H	NATURAL GAS	A	11/12/2008	0.007		
LA-0229	LA	SHINTECH PLAQUEMINE PLANT 2	EQT122-EQT125 - FOUR VCM CRACKING FURNACES	90	MMBTU/H	NATURAL GAS	B	7/10/2008	0.007		GOOD COMBUSTION PRACTICES AND CLEAN BURNING FUELS
LA-0231	LA	LAKE CHARLES GASIFICATION FACILITY	SHIFT REACTOR STARTUP HEATER	34.2	MMBTU/H	NATURAL GAS	A	6/22/2009	0.0073	MAXIMUM	GOOD DESIGN AND PROPER OPERATION
LA-0231	LA	LAKE CHARLES GASIFICATION FACILITY	METHANATION STARTUP HEATERS	56.9	MMBTU/H	NATURAL GAS	A	6/22/2009	0.0074	MAXIMUM	GOOD DESIGN AND PROPER OPERATION
*OK-0134	OK	PRYOR PLANT CHEMICAL	Nitric Acid Preheaters No. 1 (EU 401, EUG 4)	20	MMBTUH	Natural Gas	C	2/23/2009	0.0075	24-HR	Natural gas combustion
NV-0049	NV	HARRAH'S OPERATING COMPANY, INC.	BOILER - UNIT BA03	31.38	MMBTU/H	NATURAL GAS	A	8/20/2009	0.0076		OPERATING IN ACCORDANCE WITH THE MANUFACTURER'S SPECIFICATION
NV-0047	NV	NELLIS AIR FORCE BASE	BOILERS/HEATERS - NATURAL GAS-FIRED			NATURAL GAS	A	2/26/2008	0.0077		FLUE GAS RECIRCULATION
NV-0049	NV	HARRAH'S OPERATING COMPANY, INC.	BOILER - UNIT BA01	16.8	MMBTU/H	NATURAL GAS	A	8/20/2009	0.0077		OPERATING IN ACCORDANCE WITH THE MANUFACTURER'S SPECIFICATION
WI-0228	WI	WPS - WESTON PLANT	B63, S63; B64, S64 - NATURAL GAS STATION HEATER 1 AND 2	0.75	MMBTU/H	NATURAL GAS	A	10/19/2004	0.008		NATURAL GAS FUEL
NV-0037	NV	COPPER MOUNTAIN POWER	AUXILIARY BOILER	60	MMBTU/H	NATURAL GAS	A	5/14/2004	0.0083		RESTRICTION OF OPERATION TO NATURAL GAS
LA-0203	LA	OAKDALE OSB PLANT	AUXILIARY THERMAL OIL HEATER	66.5	MMBTU/H	NATURAL GAS	A	6/13/2005	0.0089	HOURLY MAXIMUM	USE OF NATURAL GAS AS FUEL AND GOOD COMBUSTION PRACTICES
TX-0364	TX	SALT CREEK GAS PLANT	HOT OIL HEATER, EPN26	32.5	MMBTU/H	NAT GAS	D	1/31/2003	0.0089		NONE INDICATED
NM-0044	NM	CLOVIS ENERGY FACILITY	AUXILIARY BOILERS (AUX-1 AND AUX-2)	33	MMBTU/H	NATURAL GAS	A	6/27/2002	0.0091		NATURAL GAS ONLY, GOOD COMBUSTION PRACTICE
TX-0364	TX	SALT CREEK GAS PLANT	HOT OIL HEATER, EPN6	12	MMBTU/H	NAT GAS	D	1/31/2003	0.0092		NONE INDICATED
VA-0243	VA	STANLEY FURNITURE	BOILER, NAT GAS & OIL	26.5	MMBTU/H	NATURAL GAS	A	12/1/2002	0.0095		EMISSION LIMITS IN T/YR ONLY
*LA-0244	LA	LAKE CHARLES CHEMICAL COMPLEX - LAB UNIT	EQT0027 - PACOL CHARGE HEATER H-201	87.3	MM BTU/hr	Natural Gas	C	11/29/2010	0.0099	HOURLY MAXIMUM	
*LA-0244	LA	LAKE CHARLES CHEMICAL COMPLEX - LAB UNIT	EQT0028 - PACOL STARTUP HEATER H-202	21	MM BTU/hr	natural gas	C	11/29/2010	0.01	HOURLY MAXIMUM	No additional Control
AR-0070	AR	GENOVA ARKANSAS I, LLC	AUXILIARY BOILER	33	MMBTU/H	NATURAL GAS	A	8/23/2002	0.012		GOOD COMBUSTION PRACTICE
AZ-0049	AZ	LA PAZ GENERATING FACILITY	AUXILIARY BOILER FOR GE TURBINE	41	MMBTU/H	NATURAL GAS	A	9/4/2003	0.015		
WI-0226	WI	WPS - WESTON PLANT	NATURAL GAS FIRED BOILER	46.2	MMBTU/H	NATURAL GAS	A	8/27/2004	0.017		NATURAL GAS
AR-0090	AR	NUCOR STEEL, ARKANSAS	PICKLE LINE BOILERS, SN-52	12.6	MBTU EAC	NATURAL GAS	A	4/3/2006	0.024		GOOD COMBUSTION PRACTICE
WI-0223	WI	LOUISIANA-PACIFIC HAYWARD	THERMAL OIL HEATER, GTS ENERGY, S31, B31	32	MMBTU/H	NATURAL GAS	C	6/17/2004	0.026		USE OF NATURAL GAS / DISTILLATE OIL, W/ RESTRICTION ON OIL USAGE
WI-0223	WI	LOUISIANA-PACIFIC HAYWARD	THERMAL OIL HEATER, GTS ENERGY, S32, B32	32	MMBTU/H	NATURAL GAS	C	6/17/2004	0.031		USE OF NATURAL GAS / DISTILLATE OIL, W/ RESTRICTION ON OIL USAGE
AR-0044	AR	ARKANSAS STEEL ASSOCIATES	PREHEATERS, LADLE, (3)	4	MMBTU/H	NATURAL GAS	D	1/5/2001	0.050	combined	NATURAL GAS COMBUSTION/GOOD COMBUSTION PRACTICES.
LA-0174	LA	PORT HUDSON OPERATIONS	POWER BOILER NO. 2	65.5	MMBTU/H	NAT GAS	D	1/25/2002	0.051		FIRED BY NATURAL GAS
LA-0174	LA	PORT HUDSON OPERATIONS	POWER BOILER NO. 2	65.5	MMBTU/H	NAT GAS	D	1/25/2002	0.051		FIRED BY NATURAL GAS
AR-0076	AR	U.S. ARMY, PINE BLUFF ARSENAL	BOILER, LABORATORY SN-PBCDF-16	1.4	mmbtu/h	NATURAL GAS	D	2/17/2004	0.071		NATURAL GAS ONLY.
KY-0087	KY	QUEBECOR WORLD FRANKLIN	BOILER, NATURAL GAS, #4	33.5	MMBTU/H	NATURAL GAS	D	7/12/2002	0.308		
PA-0210	PA	DART CONTAINER CORP OF PA	BOILER, (2)	33.5	MMBTU/H	NATURAL GAS	A	12/14/2001	0.4		
SC-0061	SC	COLUMBIA ENERGY LLC	HOT WATER HEATERS (2)	11	MMBTU/H	NATURAL GAS	A	4/9/2001	0.6		CLEAN BURNING FUEL
AL-0202	AL	CORUS TUSCALOOSA	EQUALIZING FURNACE	1.8	MMBTU/H	NATURAL GAS	D	6/3/2003	3.7		NATURAL GAS/GOOD COMBUSTION

Table D-15. VOC Best Available Control Technology RBLC Search - Natural Gas Boilers < 100 MMBtu/hr

ID	State	Company/Facility	Process Type	Throughput	Throughput Units	Primary Fuel	Permit Type	Permit Date	Emission Limit (lb/MMBtu)	Avg. Period	Control Type
TX-0408	TX	INDIAN ROCK GATHERING COMPANY LP	AUXILIARY BOILER, (2)	6	MMBTU/H	NATURAL GAS	C	11/22/2002	0.0017	EACH	
MD-0035	MD	DOMINION	VAPORIZATION HEATER			NATURAL GAS	A	8/12/2005	0.0020		NATURAL GAS COMBUSTION AND A CATALYTIC OXIDATION
MD-0040	MD	CPV ST CHARLES	BOILER	93	MMBTU/H	NATURAL GAS	A	11/12/2008	0.0020	3-HR AVERAGE	
AL-0231	AL	NUCOR DECATUR LLC	VACUUM DEGASSER BOILER	95	MMBTU/H	NATURAL GAS	D	6/12/2007	0.0026		
IN-0108	IN	NUCOR STEEL	BOILER, NATURAL GAS, (2)	34	MMBTU/H	NATURAL GAS	D	11/21/2003	0.0026		COMPLIANCE BY USING NATURAL GAS
OH-0251	OH	CENTRAL SOYA COMPANY INC.	DRYER, SOY PROTEIN CONCENTRATE - COMBUSTION	37	MMBTU/H	NATURAL GAS	D	11/29/2001	0.0027		
LA-0240	LA	FLOPAM INC.	Boilers	25.1	MMBTU/H	natural gas	A	6/14/2010	0.0030	NATURAL GAS FIRED	Good equipment design and proper combustion techniques
VA-0255	VA	VA POWER - POSSUM POINT	BOILER, AUXILIARY	99	MMBTU/H	NATURAL GAS	D	11/18/2002	0.0040	EACH UNIT	GOOD COMBUSTION PRACTICES.
OH-0255	OH	AEP WATERFORD ENERGY LLC	BOILER, NATURAL GAS	85.2	MMBTU/H	NATURAL GAS	D	3/29/2001	0.0041		
TX-0501	TX	TEXSTAR GAS PROCESS FACILITY	POWER STEAM BOILER	93	MMBTU/H	NATURAL GAS	B	7/11/2006	0.0049		
MD-0040	MD	CPV ST CHARLES	HEATER	1.7	MMBTU/H	NATURAL GAS	A	11/12/2008	0.0050		
NV-0044	NV	HARRAH'S OPERATING COMPANY, INC.	COMMERCIAL/INSTITUTIONAL-SIZE BOILERS	35.4	MMBTU/H	NATURAL GAS	A	1/4/2007	0.0050		GOOD COMBUSTION DESIGN
NV-0048	NV	GOODSPRINGS COMPRESSOR STATION	COMMERCIAL/INSTITUTIONAL-SIZE BOILER (<100 MMBTU/H)	3.85	MMBTU/H	NATURAL GAS	A	5/16/2006	0.0050		GOOD COMBUSTION PRACTICE
NV-0046	NV	GOODSPRINGS COMPRESSOR STATION	COMMERCIAL/INSTITUTIONAL BOILER	3.85	MMBTU/H	NATURAL GAS	A	5/16/2006	0.0052		GOOD COMBUSTION PROCESS
WI-0228	WI	WPS - WESTON PLANT	B63, S63; B64, S64 - NATURAL GAS STATION HEATER 1 AND 2	0.75	MMBTU/H	NATURAL GAS	A	10/19/2004	0.0053		NATURAL GAS
OH-0323	OH	TITAN TIRE CORPORATION OF BRYAN	BOILER	50.4	MMBTU/H	NATURAL GAS		6/5/2008	0.0054		
OH-0309	OH	TOLEDO SUPPLIER PARK- PAINT SHOP	BOILER (2), NATURAL GAS	20.4	MMBTU/H	NATURAL GAS	C	5/3/2007	0.0054		
NV-0049	NV	HARRAH'S OPERATING COMPANY, INC.	BOILER - UNIT FL01	14.34	MMBTU/H	NATURAL GAS	A	8/20/2009	0.0054		FLUE GAS RECIRCULATION
NV-0050	NV	MGM MIRAGE	WATER HEATERS - UNITS NY037 AND NY038 AT NEW YORK - NEW YORK	2	MMBTU/H	NATURAL GAS	A	11/30/2009	0.0054		LIMITING THE FUEL TO NATURAL GAS ONLY AND GOOD COMBUSTION PRACTICES
OK-0128	OK	MID AMERICAN STEEL ROLLING MILL	Ladle pre-heater and refractory drying			natural gas	B	9/8/2008	0.0055		Natural gas fuel
*OK-0134	OK	PRYOR PLANT CHEMICAL	Nitric Acid Preheaters No. 1 (EU 401, EUG 4)	20	MMBTUH	Natural Gas	C	2/23/2009	0.0055		good combustion
TX-0378	TX	LA PORTE POLYPROPYLENE PLANT	PACKAGE BOILER BO-4	60	MMBTU/H	NAT GAS	D	11/5/2001	0.0058		NONE INDICATED
OH-0265	OH	DRESDEN ENERGY LLC	BOILER, NATURAL GAS	49	MMBTU/H	NATURAL GAS	A	10/16/2001	0.0059		
MN-0053	MN	FAIRBAULT ENERGY PARK	BOILER, NATURAL GAS (1)	40	MMBTU/H	NATURAL GAS	A	7/15/2004	0.0060	3 HOUR AVERAGE	GOOD COMBUSTION.
WI-0227	WI	PORT WASHINGTON GENERATING STATION	GAS HEATER (P06, S06)	10	MMBTU/H	NATURAL GAS	A	10/13/2004	0.0060		NATURAL GAS FUEL
NV-0047	NV	NELLIS AIR FORCE BASE	BOILERS/HEATERS - NATURAL GAS-FIRED			NATURAL GAS	A	2/26/2008	0.0062		FLUE GAS RECIRCULATION
OK-0135	OK	PRYOR PLANT CHEMICAL	BOILERS #1 AND #2	80	MMBTU/H	NATURAL GAS	C	2/23/2009	0.0063		
TX-0364	TX	SALT CREEK GAS PLANT	HOT OIL HEATER, EPN26	32.5	MMBTU/H	NAT GAS	D	1/31/2003	0.0065		NONE INDICATED
LA-0203	LA	OAKDALE OSB PLANT	AUXILIARY THERMAL OIL HEATER	66.5	MMBTU/H	NATURAL GAS	A	6/13/2005	0.0065	HOURLY MAXIMUM	USE OF NATURAL GAS AS FUEL AND GOOD COMBUSTION PRACTICES
NV-0037	NV	COPPER MOUNTAIN POWER	AUXILIARY BOILER	60	MMBTU/H	NATURAL GAS	A	5/14/2004	0.0067		EFFECTIVE COMBUSTION SYSTEM DESIGN, 10:1 TURNDOWN CAPABILITY AND LOW NOX BURNER TECHNOLOGY
MN-0054	MN	MANKATO ENERGY CENTER	BOILER, COMMERCIAL	70	MMBTU/H	NATURAL GAS		12/4/2003	0.0070		GOOD COMBUSTION
OK-0072	OK	REDBUD POWER PLT	AUXILIARY BOILER	93	MMBUT/H	NATURAL GAS	D	5/6/2002	0.0075		BOILER DESIGN AND GOOD OPERATING PRACTICES
TX-0364	TX	SALT CREEK GAS PLANT	GLYCOL REBOILER, EPN11	2.5	MMBTU/H	NAT GAS	D	1/31/2003	0.0080		NONE INDICATED
AL-0190	AL	GE PLASTICS	FURNACE, HOT OIL, 10 MMBTU/H	10	MMBTU/H	NATURAL GAS	D	7/13/2001	0.0100		GOOD COMBUSTION PRACTICES
AL-0181	AL	DUKE ENERGY AUTAUGA, LLC	31.4 MMBTU/HR NATURAL GAS FIRED BOILER	31.4	MMBTU/H	NATURAL GAS	A	10/23/2001	0.0104		EFFICIENT COMBUSTION.
OK-0044	OK	SMITH POCOLA ENERGY PROJECT	AUXILIARY BOILERS, (2)	48	MMBTU/H	NATURAL GAS	A	8/16/2001	0.0108	combined	COMBUSTION CONTROL
IN-0110	IN	COGENTRIX LAWRENCE CO., LLC	BOILER, AUXILIARY, NATURAL GAS	35	MMBTU/H	NATURAL GAS	A	10/5/2001	0.0110		CLEAN FUEL, GOOD COMBUSTION PRACTICE
OH-0257	OH	JACKSON COUNTY POWER, LLC	AUXILIARY BOILER	76	MMBTU/H	NATURAL GAS	A	12/27/2001	0.0121		
GA-0101	GA	MURRAY ENERGY FACILITY	BOILER, AUXILIARY	31.4	MMBTU/H	NATURAL GAS	D	10/23/2002	0.0127		GOOD COMBUSTION PRACTICE
AL-0180	AL	DUKE ENERGY DALE, LLC	35 MMBTU/HR NAT. GAS FIRED AUXILIARY BOILER	35	MMBTU/H	NATURAL GAS	A	12/11/2001	0.0140		GOOD COMBUSTION
NM-0044	NM	CLOVIS ENERGY FACILITY	AUXILIARY BOILERS (AUX-1 AND AUX-2)	33	MMBTU/H	NATURAL GAS	A	6/27/2002	0.0152		CLEAN FUELS, GOOD COMBUSTION PRACTICE
AR-0090	AR	NUCOR STEEL, ARKANSAS	PICKLE LINE BOILERS, SN-52	12.6	MMBTU EACH	NATURAL GAS	A	4/3/2006	0.0159		GOOD COMBUSTION PRACTICE
CO-0058	CO	CHEYENNE STATION	HEATERS	45	MMBTU/H	NATURAL GAS	A	6/12/2004	0.0160	1-HR AVERAGE	GOOD COMBUSTION PRACTICES
OK-0129	OK	CHOUTEAU POWER PLANT	AUXILIARY BOILER	33.5	MMBTU/H	NATURAL GAS	B	1/23/2009	0.0161		GOOD COMBUSTION
TX-0458	TX	JACK COUNTY POWER PLANT	AUXILIARY BOILER	36	mmbtu/h	NATURAL GAS		7/22/2003	0.0167		
AR-0070	AR	GENOVA ARKANSAS I, LLC	AUXILIARY BOILER	33	MMBTU/H	NATURAL GAS	A	8/23/2002	0.0180		GOOD COMBUSTION PRACTICE
NV-0039	NV	CHUCK LENZIE GENERATING STATION	AUXILIARY BOILERS	44.1	MMBTU/H	NATURAL GAS	A	6/1/2001	0.0181		GOOD COMBUSTION CONTROL
WY-0067	WY	ECHO SPRINGS GAS PLANT	HOT OIL HEATER S38	84	MMBTU/H	NATURAL GAS	A	4/1/2009	0.0200		GOOD COMBUSTION PRACTICES
IA-0088	IA	ADM CORN PROCESSING - CEDAR RAPIDS	INDIRECT-FIRED DDGS DRYER	93.7	MMBTU/H	NATURAL GAS	B	6/29/2007	0.0337	AVERAGE OF 3 TEST RUNS	ROUTE PROCESS OFF-GASSES THROUGH THE DRYERS COMBUSTION CHAMBER.
NJ-0062	NJ	CONSOLIDATE EDISON DEVELOPMENT (CED)	FUEL GAS HEATERS (3 UNITS)	4.62	MMBTU/H	NATURAL GAS	A	10/22/2002	0.0476		GOOD COMBUSTION PRACTICE
AL-0202	AL	CORUS TUSCALOOSA	EQUALIZING FURNACE	1.8	MMBTU/H	NATURAL GAS	D	6/3/2003	0.2778		NATURAL GAS/GOOD COMBUSTION

Table D-16. NO$_X$ Best Available Control Technology RBLC Search - Emergency Generator

ID	State	Company/Facility	Process Type	Throughput	Throughput Units	Primary Fuel	Permit Type[1]	Permit Date	Emission Limit (lb/MMBtu)	Avg. Period	Control Type
OH-0255	OH	AEP WATERFORD ENERGY LLC	EMERGENCY GENERATOR	1000	KW	DIESEL	D	03/29/2001	0.05		
MD-0037	MD	MEDIMMUNE FREDERICK CAMPUS	TWO (2) DIESEL (NO. 2 FUEL OIL) FIRED, NON-EMERGENCY GENERATORS EACH RATED AT 2500 KILOWATTS (3604 BRAKE HORSEPOWER)	2500	KW	DIESEL (NO. 2 FUEL OIL)	A	01/28/2008	0.53	EXCEPT START-UP NOT TO EXCEED 9 MINUTES	SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM FOR EACH GENERATOR
MS-0086	MS	CHEVRON PRODUCTS COMPANY, PASCAGOULA REFINERY	TEMPORARY, PORTABLE CRUDE I GENERATOR			DIESEL	D	05/08/2007	0.62	3-HR ROLLING AVERAGE	SELECTIVE CATALYTIC REDUCTION (SCR)
AK-0064	AK	DUTCH HARBOR POWER PLANT	I.C.	5000	KW	FUEL OIL	B	01/31/2007	0.88	3 HOURS	REDUCE NOX BY 90%
AK-0059	AK	USAF EARECKSON AIR STATION	IC ENGINE, DIESEL, (2)	3000	KW	DIESEL	D	09/29/2003	0.95	3-H AVG	SCR
PA-0209	PA	ORCHARD PARK GENERATING STATION	IC ENGINE, GENERATOR	8086	BHP	FUEL OIL	A	11/08/2002	1.30		LEAN BURN, SCR, LOW EMISSION COMBUSTION CONTROL
IA-0067	IA	WALTER SCOTT JR. ENERGY CENTER	EMERGENCY GENERATOR	97.73	GAL/H	DIESEL FUEL	B	06/17/2003	1.71		GOOD COMBUSTION PRACTICES
NC-0074	NC	BRIDGESTONE/FIRESTONE NORTH AMERICAN TIRE	IC ENGINES, AIR COMPRESSORS, DIESEL, (5)	4.46	MMBTU/H	DIESEL	D	01/24/2003	1.75	each	IGNITION TIMING RETARD
NH-0015	NH	CONCORD STEAM CORPORATION	EMRGENCY GENERATOR 1	5.6	MMBTU/H	DIESEL FUEL	A	02/27/2009	1.98	AVERAGE OF 3 1-HOUR TEST RUNS	LESS THAN 500 HOURS OF OPERATION PER CONSECUTIVE 12 MONTH PERIOD
OK-0091	OK	CARDINAL FG CO./ CARDINAL GLASS PLANT	IC ENGINES, EMERGENCY GENERATORS (2)	2000	KW	DIESEL	A	03/18/2003	2.04	see note	ENGINE DESIGN AND LIMIT ON HOURS OF OPERATION (<500 H/YR)
OK-0090	OK	DUKE ENERGY STEPHENS, LLC STEPHENS ENERGY	IC ENGINE, BACKUP GENERATOR, DIESEL	749	BHP	DIESEL	D	03/21/2003	2.16		ENGINE DESIGN AND LIMITED HOURS OF OPERATION (<100 H/YR)
IA-0095	IA	TATE & LYLE INDGREDIENTS AMERICAS, INC.	FIRE PUMP ENGINE	575	HP	DIESEL	A	09/19/2008	2.52	AVERAGE OF THREE STACK TEST RUNS	
NC-0074	NC	BRIDGESTONE/FIRESTONE NORTH AMERICAN TIRE	IC ENGINE, DIESEL GENERATOR, (2)	15.7	MMBTU/H	DIESEL	D	01/24/2003	2.79	each	IGNITION TIMING RETARD
OK-0070	OK	GENOVA OK I POWER PROJECT	DIESEL ENGINE, BACKUP GENERATOR	750	KW	DIESEL	A	06/13/2002	3.01		ENGINE DESIGN AND LIMITATION OF HOURS
IA-0064	IA	ROQUETTE AMERICA	710 HP DIESEL STARTING ENGINE	38.4	GAL/H	DIESEL	A	01/31/2003	3.10		GOOD COMBUSTION PRACTICES
OH-0275	OH	PSI ENERGY-MADISON STATION	EMERGENCY DIESEL GENERATOR, 2	17.21	MMBTU/H	DIESEL FUEL	A	08/24/2004	3.20		
LA-0204	LA	PLAQUEMINE PVC PLANT	LARGE EMERGENCY ENGINES			DIESEL	A	02/27/2009	3.20		GOOD COMBUSTION PRACTICES AND GASEOUS FUEL BURNING
NJ-0036	NJ	AES RED OAK LLC	EMERGENCY GENERATOR	49	MMBTU/H	DIESEL FUEL	D	10/24/2001	3.26		LIMITED USE
MN-0053	MN	FAIRBAULT ENERGY PARK	IC ENGINE, LARGE, FUEL OIL (1)	670	HP	DIESEL	A	07/15/2004	3.28		GOOD COMBUSTION.
KS-0028	KS	NEARMAN CREEK POWER STATION	EMERGENCY BLACK START GENERATOR	24.1	MMBTU/H	NO. 2 FUEL OIL	A	10/18/2005	3.52	FULL LOAD OPERATIONS	EMERGENCY DIESEL GENERATORS HAVE NOT BEEN REQUIRED TO INSTALL ADDITIONAL NOX CONTROLS BECAUSE OF INTERMITTENT OPERATION.
OH-0317	OH	OHIO RIVER CLEAN FUELS, LLC	EMERGENCY GENERATOR	2922	HP	DIESEL FUEL OIL	A	11/20/2008	3.56		GOOD COMBUSTION PRACTICES, GOOD ENGINE DESIGN, IGNITION TIMING RETARD, TURBOCHARGER, AND LOW-TEMPERATURE AFTERCOOLER
IA-0088	IA	ADM CORN PROCESSING - CEDAR RAPIDS	EMERGENCY GENERATOR	1500	KW	DIESEL	B	06/29/2007	3.90	AVERAGE OF 3 TEST RUNS	NO SPECIFIC CONTROL TECHNOLOGY IS SPECIFED. ENGINE IS REQUIRED TO MEET LIMITS ESTABLISHED AS BACT (TIER 2 NONROAD). THIS COULD REQUIRE ANY NUMBER OF CONTROL TECHNOLOGIES AND OPERATIONAL REQ. TO MEET THE BACT STANDARD.
AR-0076	AR	U.S. ARMY, PINE BLUFF ARSENAL	IC ENGINE, EMERGENCY GENERATOR (2)	2500	KW	DIESEL FUEL	D	02/17/2004	3.97	EACH	LIMITATION OF OPERATING HOURS TO LESS THAN 1200 COMBINED HOURS/YR FOR SN-PBCDF-09 AND SN-PBCDF-10 AND LESS THAN 500 HOURS/YR FOR SN-PBCDF-12.
AK-0066	AK	ENDICOTT PRODUCTION FACILITY, LIBERTY DEVELOPMENT PROJEC	EU ID 58, CAMP ENGINE 3	1041	HP	DISTILLATE	B	06/15/2009	4.07		GOOD COMBUSTION PRACTICES
AR-0094	AR	JOHN W. TURK JR. POWER PLANT	EMERGENCY GENERATOR AND FIRE PUMP ENGINE				A	11/05/2008	4.14	3 HOUR	GOOD COMBUSTION
CA-1014	CA	POWER SYSTEM ASSOCIATES/JOHNSON POWER SYSTEMS	IC ENGINE, EMERGENCY, COMPRESSION IGNITION	536	BHP	DIESEL	A	07/11/2001	4.16		TURBOCHARGED AND AFTERCOOLED
WV-0023	WV	MAIDSVILLE	EMERGENCY GENERATOR	1801	HP	DIESEL	A	03/02/2004	4.56		GOOD COMBUSTION PRACTICES
LA-0231	LA	LAKE CHARLES GASIFICATION FACILITY	EMERGENCY DIESEL POWER GENERATOR ENGINES (2)	1341	HP EACH	DIESEL	A	06/22/2009	5.01	MAXIMUM (EACH)	COMPLY WITH 40 CFR 60 SUBPART IIII
LA-0219	LA	CREOLE TRAIL LNG IMPORT TERMINAL	FIREWATER PUMP DIESEL ENGINE	525	HP	DIESEL	A	08/15/2007	5.05	HOURLY MAXIMUM	GOOD COMBUSTION PRACTICES AND GOOD ENGINE DESIGN INCORPORATING FUEL INJECTION TIMING RETARDATION (ITR)
OK-0128	OK	MID AMERICAN STEEL ROLLING MILL	Emergency Generator	1200	HP	No. 2 diesel	B	09/08/2008	5.11		500 hours per year operations
NV-0050	NV	MGM MIRAGE	EMERGENCY GENERATORS - UNITS LX024 AND LX025 AT LUXOR	2206	HP	DIESEL OIL	A	11/30/2009	5.15		TURBOCHARGING, AFTER-COOLING, AND LEAN-BURN TECHNOLOGY
CA-1010	CA	POWER SYSTEM ASSOCIATES/JOHNSON POWER SYSTEMS	IC ENGINE, EMERGENCY, COMPRESSION IGNITION	764	BHP	DIESEL	A	07/11/2001	5.36		TURBOCHARGE AND AFTERCOOLED
AK-0060	AK	DUTCH HARBOR SEAFOOD PROCESSING FACILITY	IC ENGINE, GENERATOR, FUEL OIL, (3)	2220	KW	DISTILLATE FUEL OIL	D	10/10/2003	5.58		WATER INJECTION, LOW NOX DESIGN
FL-0310	FL	SHADY HILLS GENERATING STATION	2.5 MW EMERGENCY GENERATOR	2.5	MW	ULTRA LOW S OIL	B	01/12/2009	5.98	3 ONE HOUR TEST	PURCHASE MODEL IS AT LEAST AS STRINGENT AS THE BACT VALUES, UNDER EPA CERTIFICATION.
LA-0219	LA	CREOLE TRAIL LNG IMPORT TERMINAL	FIREWATER PUMP DIESEL ENGINE	660	HP	DIESEL	A	08/15/2007	6.00	HOURLY MAXIMUM	GOOD COMBUSTION PRACTICES AND GOOD ENGINE DESIGN INCORPORATING FUEL INJECTION TIMING RETARDATION (ITR)
OH-0254	OH	DUKE ENERGY WASHINGTON COUNTY LLC	EMERGENCY DIESEL-FIRED GENERATOR	600	KW	DIESEL	D	08/14/2003	6.06		LOW SULFUR FUEL, COMBUSTION CONTROL
NV-0047	NV	NELLIS AIR FORCE BASE	LARGE INTERNAL COMBUSTION ENGINES (>500 HP)			DIESEL OIL	A	02/26/2008	6.57		TURBOCHARGER AND AFTERCOOLER
LA-0219	LA	CREOLE TRAIL LNG IMPORT TERMINAL	DIESEL EMERGENCY GENERATOR NOS. 1 & 2	2168	HP EACH	DIESEL	A	08/15/2007	6.88	HOURLY MAXIMUM	GOOD COMBUSTION PRACTICES AND GOOD ENGINE DESIGN INCORPORATING FUEL INJECTION TIMING RETARDATION (ITR)
AK-0065	AK	NAKNEK POWER PLANT	CATERPILLAR 3512B GENERATOR ENGINES (3)	1050	KW	DIESEL	B	12/11/2006	6.95	1 HOUR	EPA CERTIFIED LOW EMISSIONS STRATEGY
LA-0194	LA	SABINE PASS LNG TERMINAL	FIREWATER PUMP DIESEL ENGINES 1-3	660	HP EACH	DIESEL	A	11/24/2004	7.27	HOURLY MAXIMUM	GOOD ENGINE DESIGN AND PROPER OPERATING PRACTICES
AK-0064	AK	DUTCH HARBOR POWER PLANT	I.C.	5211	KW	FUEL OIL	B	01/31/2007	8.79	3 HOURS	FUEL INJECTION TIMING RETARD AND AFTERCOOLER (PART OF ENGINE DESIGN)
MN-0071	MN	FAIRBAULT ENERGY PARK	EMERGENCY GENERATOR	1750	KW	NO. 2		06/05/2007	9.43	3 HOUR AVERAGE	
NV-0049	NV	HARRAH'S OPERATING COMPANY, INC.	LARGE INTERNAL COMBUSTION ENGINES (>600 HP) - UNIT HA13	1232	HP	DIESEL OIL	A	08/20/2009	9.43		THE UNIT IS EQUIPPED WITH A TURBOCHARGER.
IA-0058	IA	GREATER DES MOINES ENERGY CENTER	EMERGENCY GENERATOR	700	KW	DIESEL	A	04/10/2002	9.50		RETARDED INGITION TIMING (3-4 DEGREES)
NJ-0073	NJ	TRIGEN	DUAL FUEL ENGINES ON 100 % DISTILLATE FUEL OIL	1	MMGAL/YR	DISTILLATE FUEL OIL	A	03/08/2008	10.40	3-HOUR AVERAGE	
MN-0054	MN	MANKATO ENERGY CENTER	INTERNAL COMBUSTION ENGINE, LARGE	1850	HP	DIESEL FUEL		12/04/2003	11.00		GOOD COMBUSTION
WI-0207	WI	ACE ETHANOL - STANLEY	IC ENGINE, DIESEL GENERATOR SET, B70	1850	BHP		A	01/21/2004	11.26		LIMIT ON HOURS OF OPERATION (16.7 HRS/MO, 12 MO. AVG.)
LA-0122	LA	MANSFIELD MILL	ADMINISTRATION BUILDING DIESEL GENERATOR	587	HP	DIESEL	D	08/14/2001	12.12		PREVENTATIVE MAINTENANCE
AR-0051	AR	DUKE ENERGY-JACKSON FACILITY	GENERATOR, DIESEL-FIRED	671	HP	DIESEL FUEL	D	04/01/2002	12.13		GOOD OPERATING PRACTICE
LA-0122	LA	MANSFIELD MILL	AUXILIARY DIESEL GENERATORS NO.1 & NO.2	1100	HP EACH	DIESEL FUEL	D	08/14/2001	12.15	EACH	PREVENTATIVE MAINTENANCE
LA-0211	LA	GARYVILLE REFINERY	EMERGENCY GENERATORS (DOCK & TANK FARM) (21-08 & 22-08)			DIESEL	D	12/27/2006	12.18	ANNUAL AVERAGE	USE OF DIESEL WITH A SULFUR CONTENT OF 15 PPMV OR LESS
LA-0122	LA	MANSFIELD MILL	CATERPILLAR BACK-UP DIESEL AIR COMPRESSORS, 2	775	HP EACH	DIESEL FUEL	D	08/14/2001	19.58	EACH	PREVENTATIVE MAINTENANCE
*VA-0305	VA	INGENCO K&O FACILITY	ELECTRIC GENERATION	550	HHP	DISTILLATE OIL	A	09/26/2007	39.16		CHARGE AIR COOLING SYSTEMS AND GOOD COMBUSTION PRACTICES

1. Permit types: A = New/Greenfield facility, B = Adding new process to an existing facility, C = Modifying an existing process at an existing facility, D = Both B & C.

Table D-17. SO_2 Best Available Control Technology RBLC Search - Emergency Generator

ID	State	Company/Facility	Process Type	Throughput	Throughput Units	Primary Fuel	Permit Type[1]	Permit Date	Emission Limit (lb/MMBtu)	Avg. Period	Control Type
OH-0255	OH	AEP WATERFORD ENERGY LLC	EMERGENCY GENERATOR	1000	KW	DIESEL	D	03/29/2001	0.001		LOW SULFUR FUEL
LA-0231	LA	LAKE CHARLES GASIFICATION FACILITY	EMERGENCY DIESEL POWER GENERATOR ENGINES (2)	1341	HP EACH	DIESEL	A	06/22/2009	0.003	MAXIMUM (EACH)	COMPLY WITH 40 CFR 60 SUBPART IIII
AR-0094	AR	JOHN W. TURK JR. POWER PLANT	EMERGENCY GENERATOR AND FIRE PUMP ENGINE				A	11/05/2008	0.005	3 HOUR	LOW SULFUR DIESEL USE
NV-0047	NV	NELLIS AIR FORCE BASE	LARGE INTERNAL COMBUSTION ENGINES (>500 HP)			DIESEL OIL	A	02/26/2008	0.017		LIMITING SULFUR CONTENT IN THE DIESEL OIL TO 0.05%
OH-0266	OH	UNIVERSITY OF CINCINNATI	DIESEL FIRED ENGINES (2), 2 MW, 2922 BHP	19.17	MMBTU/H	DIESEL FUEL OIL	A	08/15/2002	0.043		SULFUR CONTENT OF DIESEL FUEL LESS THAN 0.05 PERCENT.
KS-0028	KS	NEARMAN CREEK POWER STATION	EMERGENCY BLACK START GENERATOR	24.1	MMBTU/H	NO. 2 FUEL OIL	A	10/18/2005	0.050	FULL LOAD OPERATIONS	GOOD COMBUSTION CONTROL
NJ-0036	NJ	AES RED OAK LLC	EMERGENCY GENERATOR	49	MMBTU/H	DIESEL FUEL	D	10/24/2001	0.050		LOW SULFUR FUEL
OK-0091	OK	CARDINAL FG CO./ CARDINAL GLASS PLANT	IC ENGINES, EMERGENCY GENERATORS (2)	2000	KW	DIESEL	A	03/18/2003	0.050		LOW SULFUR FUEL, < 0.05% S
MN-0053	MN	FAIRBAULT ENERGY PARK	IC ENGINE, LARGE, FUEL OIL (1)	670	HP	DIESEL	A	07/15/2004	0.051		LOW SULFUR FUEL.
IA-0067	IA	WALTER SCOTT JR. ENERGY CENTER	EMERGENCY GENERATOR	97.73	GAL/H	DIESEL FUEL	B	06/17/2003	0.052		GOOD COMBUSTION PRACTICES AND LOW SULFUR FUEL
CO-0055	CO	LAMAR LIGHT & POWER POWER PLANT	DIESEL ENGINES FOR SWITCHING, LOCOMOTIVE & FIRE PUMP	1500	HP	DIESEL	D	02/03/2006	0.060		LOW SULFUR FUEL. LESS TAN 0.05 BY WHEIGHT
AR-0076	AR	U.S. ARMY, PINE BLUFF ARSENAL	IC ENGINE, EMERGENCY GENERATOR (2)	2500	KW	DIESEL FUEL	D	02/17/2004	0.070	EACH	LOW SULFUR DIESEL: LESS THAN OR EQUAL TO 0.05 WT % S. ALSO: LIMITATION OF OPERATING HOURS TO LESS THAN 1200 COMBINED HOURS/YR FOR SN-PBCDF-09 AND SN-PBCDF-10 AND LESS THAN 500 HOURS/YR FOR SN-PBCDF-12.
NV-0050	NV	MGM MIRAGE	EMERGENCY GENERATORS - UNITS LX024 AND LX025 AT LUXOR	2206	HP	DIESEL OIL	A	11/30/2009	0.079		LIMITING SULFUR CONTENT IN THE DIESEL OIL TO 0.03%
SC-0064	SC	SCE&G - JASPER COUNTY GENERATING FACILITY	GENERATOR, EMERGENCY,DIESEL FUEL	2000	KW	DIESEL	A	05/23/2002	0.132		LOW SULFUR (0.05%) DIESEL
CA-0988	CA	PACIFIC BELL	IC ENGINES	2935	HP	DIESEL FUEL	A	02/01/2003	0.139		
IA-0088	IA	ADM CORN PROCESSING - CEDAR RAPIDS	EMERGENCY GENERATOR	1500	KW	DIESEL	B	06/29/2007	0.147	AVERAGE OF 3 TEST RUNS	BURN LOW-SULFUR DIESEL FUEL. 0.05% BY WEIGHT OR LESS NOT TO EXCEED THE NSPS REQUIREMENT.
IA-0095	IA	TATE & LYLE INDGREDIENTS AMERICAS, INC.	EMERGENCY GENERATOR	700	KW	DIESEL	A	09/19/2008	0.149	AVERAGE OF THREE STACK TEST RUNS	FUEL SULFUR LIMIT
IA-0095	IA	TATE & LYLE INDGREDIENTS AMERICAS, INC.	FIRE PUMP ENGINE	575	HP	DIESEL	A	09/19/2008	0.149	AVERAGE OF THREE STACK TEST RUNS	LIMIT ON SULFUR IN FUEL
MN-0071	MN	FAIRBAULT ENERGY PARK	EMERGENCY GENERATOR	1750	KW	NO. 2		06/05/2007	0.157	3 HOUR AVERAGE	
NV-0049	NV	HARRAH'S OPERATING COMPANY, INC.	LARGE INTERNAL COMBUSTION ENGINES (>600 HP) - UNIT HA13	1232	HP	DIESEL OIL	A	08/20/2009	0.157		THE UNIT SHALL COMBUST ONLY LOW-SULFUR DIESEL OIL WITH A SULFUR CONTENT LESS THAN 0.05%.
OK-0090	OK	DUKE ENERGY STEPHENS, LLC STEPHENS ENERGY	IC ENGINE, BACKUP GENERATOR, DIESEL	749	BHP	DIESEL	D	03/21/2003	0.157		USE OF LOW SULFUR DIESEL FUEL (< 0.05% S BY WT)
OK-0129	OK	CHOUTEAU POWER PLANT	EMERGENCY DIESEL GENERATOR (2200 HP)	2200	HP	LOW SULFUR DIESEL	B	01/23/2009	0.159		LOW SULFUR DIESEL 0.05%S
OK-0128	OK	MID AMERICAN STEEL ROLLING MILL	Emergency Generator	1200	HP	No. 2 diesel	B	09/08/2008	0.160		500 hours per year, 0.05% sulfur diesel fuel
OH-0254	OH	DUKE ENERGY WASHINGTON COUNTY LLC	EMERGENCY DIESEL-FIRED GENERATOR	600	KW	DIESEL	D	08/14/2003	0.195		LOW SULFUR FUEL, COMBUSTION CONTROL
OK-0072	OK	REDBUD POWER PLT	DIESEL ENGINE, EMERGENCY GENERATOR	1818	HP	DIESEL FUEL	D	05/06/2002	0.400		
VA-0276	VA	INGENCO - CHARLES CITY PLANT	IC ENGINES, (48)	550	HP	FUEL OIL	A	06/20/2003	0.500		GOOD COMBUSTION PRACTICES
OH-0275	OH	PSI ENERGY-MADISON STATION	EMERGENCY DIESEL GENERATOR, 2	17.21	MMBTU/H	DIESEL FUEL	A	08/24/2004	0.500		SULFUR LIMITED TO 0.05 % BY WEIGHT. OPERATIONS LIMITED TO 499 HOUR PER YEAR
MN-0054	MN	MANKATO ENERGY CENTER	INTERNAL COMBUSTION ENGINE, LARGE	1850	HP	DIESEL FUEL		12/04/2003	0.511		LOW SULFUR FUEL
PA-0271	PA	MERCK & CO. WESTPOINT	MOBILE EMERGENCY GENERATOR			DIESEL	B	02/23/2007	0.780		
LA-0122	LA	MANSFIELD MILL	AUXILIARY DIESEL GENERATORS NO.1 & NO.2	1100	HP EACH	DIESEL FUEL	D	08/14/2001	0.786	EACH	PREVENTATIVE MAINTENANCE
LA-0122	LA	MANSFIELD MILL	ADMINISTRATION BUILDING DIESEL GENERATOR	587	HP	DIESEL	D	08/14/2001	0.803		PREVENTATIVE MAINTENANCE
TX-0407	TX	STERNE ELECTRIC GENERATING FACILITY	EMERGENCY GENERATOR	1350	HP	DIESEL	A	12/06/2002	0.806		DISTILLATE FUEL OIL CONTAINING NO MORE THAN 0.2 WEIGHT PERCENT OF SULFUR.
LA-0122	LA	MANSFIELD MILL	CATERPILLAR BACK-UP DIESEL AIR COMPRESSORS, 2	775	HP EACH	DIESEL FUEL	D	08/14/2001	0.811	EACH	PREVENTATIVE MAINTENANCE
WV-0023	WV	MAIDSVILLE	EMERGENCY GENERATOR	1801	HP	DIESEL	A	03/02/2004	1.418		SULFUR CONTENT IN THE FUEL LIMITED TO 0.05% BY WEIGHT
NC-0074	NC	BRIDGESTONE/FIRESTONE NORTH AMERICAN TIRE	IC ENGINE, DIESEL GENERATOR, (2)	15.7	MMBTU/H	DIESEL	D	01/24/2003	2.300		
NC-0074	NC	BRIDGESTONE/FIRESTONE NORTH AMERICAN TIRE	IC ENGINES, AIR COMPRESSORS, DIESEL, (5)	4.46	MMBTU/H	DIESEL	D	01/24/2003	2.300		
NC-0075	NC	FORT BRAGG	IC ENGINES, DIESEL, (17)			DIESEL	D	08/20/2001	2.300		
*VA-0305	VA	INGENCO K&O FACILITY	ELECTRIC GENERATION	550	HHP	DISTILLATE OIL	A	09/26/2007	5.009		GOOD COMBUSTIONS PRACTICES AND CONTINUOUS MONITORING DEVICES

1. Permit types: A = New/Greenfield facility, B = Adding new process to an existing facility, C = Modifying an existing process at an existing facility, D = Both B & C.

Table D-18. CO Best Available Control Technology RBLC Search - Emergency Generator

ID	State	Company/Facility	Process Type	Throughput	Throughput Units	Primary Fuel	Permit Type[1]	Permit Date	Emission Limit (lb/MMBtu)	Avg. Period	Control Type
OH-0255	OH	AEP WATERFORD ENERGY LLC	EMERGENCY GENERATOR	1000	KW	DIESEL	D	03/29/2001	0.015		
NJ-0036	NJ	AES RED OAK LLC	EMERGENCY GENERATOR	49	MMBTU/H	DIESEL FUEL	D	10/24/2001	0.023		GOOD COMBUSTION PRACTICE
OH-0266	OH	UNIVERSITY OF CINCINNATI	DIESEL FIRED ENGINES (2), 2 MW, 2922 BHP	19.17	MMBTU/H	DIESEL FUEL OIL	A	08/15/2002	0.09		
LA-0219	LA	CREOLE TRAIL LNG IMPORT TERMINAL	FIREWATER PUMP DIESEL ENGINE	660	HP	DIESEL	A	08/15/2007	0.18	HOURLY MAXIMUM	GOOD COMBUSTION PRACTICES AND GOOD ENGINE DESIGN INCORPORATING FUEL INJECTION TIMING RETARDATION (ITR)
LA-0231	LA	LAKE CHARLES GASIFICATION FACILITY	EMERGENCY DIESEL POWER GENERATOR ENGINES (2)	1341	HP EACH	DIESEL	A	06/22/2009	0.18	MAXIMUN (EACH)	COMPLY WITH 40 CFR 60 SUBPART IIII
NV-0047	NV	NELLIS AIR FORCE BASE	LARGE INTERNAL COMBUSTION ENGINES (>500 HP)			DIESEL OIL	A	02/26/2008	0.19		TURBOCHARGER AND AFTERCOOLER
OK-0091	OK	CARDINAL FG CO./ CARDINAL GLASS PLANT	IC ENGINES, EMERGENCY GENERATORS (2)	2000	KW	DIESEL	A	03/18/2003	0.20		ENGINE DESIGN AND LIMIT ON HOURS OF OPERATION (<500 H/YR)
KS-0028	KS	NEARMAN CREEK POWER STATION	EMERGENCY BLACK START GENERATOR	24.1	MMBTU/H	NO. 2 FUEL OIL	A	10/18/2005	0.29	FULL LOAD OPERATIONS	GOOD ENGINE DESIGN IS PROPOSED AS BACT
OK-0070	OK	GENOVA OK I POWER PROJECT	DIESEL ENGINE, BACKUP GENERATOR	750	KW	DIESEL	A	06/13/2002	0.31		ENGINE DESIGN
CA-1010	CA	POWER SYSTEM ASSOCIATES/JOHNSON POWER SYSTEMS	IC ENGINE, EMERGENCY, COMPRESSION IGNITION	764	BHP	DIESEL	A	07/11/2001	0.32		
LA-0194	LA	SABINE PASS LNG TERMINAL	FIREWATER PUMP DIESEL ENGINES 1-3	660	HP EACH	DIESEL	A	11/24/2004	0.33	HOURLY MAXIMUM	GOOD ENGINE DESIGN AMD PROPER OPERATING PRACTICES
AK-0059	AK	USAF EARECKSON AIR STATION	IC ENGINE, DIESEL, (2)	3000	KW	DIESEL	D	09/29/2003	0.43		SCR OXIDATION CATALYST
CA-1012	CA	POWER SYSTEM ASSOCIATES/JOHNSON POWER SYSTEMS	IC ENGINES, EMERGENCY, COMPRESSION IGNITION	685	BHP	DIESEL	A	07/11/2001	0.45		
AK-0061	AK	SNAKE RIVER POWER PLANT	WARTSILA 12V32B DIESEL ELECTRIC GENERATOR	5211	KW	DIESEL FUEL	B	11/05/2004	0.59	3-HOUR @ 100% LOAD	GOOD COMBUSTION PRACTICES
CO-0055	CO	LAMAR LIGHT & POWER POWER PLANT	DIESEL ENGINES FOR SWITCHING, LOCOMOTIVE & FIRE PUMP	1500	HP	DIESEL	D	02/03/2006	0.61	DURATION OF TESTS	GOOD COMBUSTION MANAGEMENT PRACTICE
PA-0271	PA	MERCK & CO. WESTPOINT	MOBILE EMERGENCY GENERATOR			DIESEL	B	02/23/2007	0.68		
NV-0050	NV	MGM MIRAGE	EMERGENCY GENERATORS - UNITS LX024 AND LX025 AT LUXOR	2206	HP	DIESEL OIL	A	11/30/2009	0.71		TURBOCHARGER AND GOOD COMBUSTION PRACTICES
MS-0086	MS	CHEVRON PRODUCTS COMPANY, PASCAGOULA REFINERY	TEMPORARY, PORTABLE CRUDE I GENERATOR			DIESEL	D	05/08/2007	0.74	3-HR ROLLING AVERAGE	
MN-0053	MN	FAIRBAULT ENERGY PARK	IC ENGINE, LARGE, FUEL OIL (1)	670	HP	DIESEL	A	07/15/2004	0.76	3 HOUR AVERAGE	GOOD COMBUSTION.
LA-0204	LA	PLAQUEMINE PVC PLANT	LARGE EMERGENCY ENGINES			DIESEL	A	02/27/2009	0.85		GOOD COMBUSTION PRACTICES AND GASEOUS FUEL BURNING
WI-0207	WI	ACE ETHANOL - STANLEY	IC ENGINE, DIESEL GENERATOR SET, B70	1850	BHP		A	01/21/2004	0.87		LIMITED OPERATION, DESIGN
LA-0219	LA	CREOLE TRAIL LNG IMPORT TERMINAL	FIREWATER PUMP DIESEL ENGINE	525	HP	DIESEL	A	08/15/2007	1.20	HOURLY MAXIMUM	GOOD COMBUSTION PRACTICES AND GOOD ENGINE DESIGN INCORPORATING FUEL INJECTION TIMING RETARDATION (ITR)
WV-0023	WV	MAIDSVILLE	EMERGENCY GENERATOR	1801	HP	DIESEL	A	03/02/2004	1.93		GOOD COMBUSTION PRACTICES
OH-0317	OH	OHIO RIVER CLEAN FUELS, LLC	EMERGENCY GENERATOR	2922	HP	DIESEL FUEL OIL	A	11/20/2008	2.04		GOOD COMBUSTION PRACTICES AND GOOD ENGINE DESIGN
MN-0071	MN	FAIRBAULT ENERGY PARK	EMERGENCY GENERATOR	1750	KW	NO. 2		06/05/2007	2.16	3 HOUR AVERAGE	
AK-0066	AK	ENDICOTT PRODUCTION FACILITY, LIBERTY DEVELOPMENT PROJECT	EU ID 58, CAMP ENGINE 3	1041	HP	DISTILLATE	B	06/15/2009	2.25		GOOD COMBUSTION PRACTICES
IA-0088	IA	ADM CORN PROCESSING - CEDAR RAPIDS	EMERGENCY GENERATOR	1500	KW	DIESEL	B	06/29/2007	2.25	AVERAGE OF 3 TEST RUNS	NO SPECIFIC CONTROL TECHNOLOGY IS SPECIFED. ENGINE IS REQUIRED TO MEET LIMITS ESTABLISHED AS BACT (TIER 2 NONROAD). THIS COULD REQUIRE ANY NUMBER OF CONTROL TECHNOLOGIES AND OPERATIONAL REQ. TO MEET THE BACT STANDARD.
AR-0094	AR	JOHN W. TURK JR. POWER PLANT	EMERGENCY GENERATOR AND FIRE PUMP ENGINE				A	11/05/2008	2.26	3 HOUR	
*FL-0322	FL	SWEET SORGHUM-TO-ETHANOL ADVANCED BIOREFINERY	Two 2682 HP Emergency Generators	0		ULSD	A	12/23/2010	2.26		
ID-0018	ID	LANGLEY GULCH POWER PLANT	EMERGENCY GENERATOR ENGINE	750	KW	DIESEL	A	06/25/2010	2.26		TIER 2 ENGINE-BASED, GOOD COMBUSTION PRACTICES (GCP)
AK-0065	AK	NAKNEK POWER PLANT	CATERPILLAR 3512B GENERATOR ENGINES (3)	1050	KW	DIESEL	B	12/11/2006	2.46	HOUR	EPA CERTIFIED LOW EMISSIONS STRATEGY
LA-0122	LA	MANSFIELD MILL	ADMINISTRATION BUILDING DIESEL GENERATOR	587	HP	DIESEL	D	08/14/2001	2.61		PREVENTATIVE MAINTENANCE
LA-0211	LA	GARYVILLE REFINERY	EMERGENCY GENERATORS (DOCK & TANK FARM) (21-08 & 22-08)			DIESEL	D	12/27/2006	2.63	ANNUAL AVERAGE	USE OF DIESEL WITH A SULFUR CONTENT OF 15 PPMV OR LESS
OK-0090	OK	DUKE ENERGY STEPHENS, LLC STEPHENS ENERGY	IC ENGINE, BACKUP GENERATOR, DIESEL	749	BHP	DIESEL	D	03/21/2003	2.66		ENGINE DESIGN AND GOOD COMBUSTION PRACTICES
LA-0122	LA	MANSFIELD MILL	CATERPILLAR BACK-UP DIESEL AIR COMPRESSORS, 2	775	HP EACH	DIESEL FUEL	D	08/14/2001	2.74	EACH	PREVENTATIVE MAINTENANCE
VA-0276	VA	INGENCO - CHARLES CITY PLANT	IC ENGINES, (48)	550	HP	FUEL OIL	A	06/20/2003	3.30		LIMITING THE TREATED LANDFILL GAS HEAT INPUT RATION TO 50% AND A LANDFILL GAS TREATMENT SYSTEM.
LA-0122	LA	MANSFIELD MILL	AUXILIARY DIESEL GENERATORS NO.1 & NO.2	1100	HP EACH	DIESEL FUEL	D	08/14/2001	3.79	EACH	PREVENTATIVE MAINTENANCE
FL-0310	FL	SHADY HILLS GENERATING STATION	2.5 MW EMERGENCY GENERATOR	2.5	MW	ULTRA LOW S OIL	B	01/12/2009	7.37	3 ONE HOUR TEST RUNS BY EPA METHOD 10	PURCHASED MODEL IS AT LEAST AS STRINGENT AS THE BACT VALUES UNDER EPA'S CERTIFICATION.
OH-0254	OH	DUKE ENERGY WASHINGTON COUNTY LLC	EMERGENCY DIESEL-FIRED GENERATOR	600	KW	DIESEL	D	08/14/2003	7.42		LOW SULFUR FUEL, COMBUSTION CONTROL
OK-0072	OK	REDBUD POWER PLT	DIESEL ENGINE, EMERGENCY GENERATOR	1818	HP	DIESEL FUEL	D	05/06/2002	21.62		ENGINE DESIGN
*VA-0305	VA	INGENCO K&O FACILITY	ELECTRIC GENERATION	550	HHP	DISTILLATE OIL	A	09/26/2007	39.16		ENGINE CONTROL MODULE

1. Permit types: A = New/Greenfield facility, B = Adding new process to an existing facility, C = Modifying an existing process at an existing facility, D = Both B & C.

Table D-19. PM Best Available Control Technology RBLC Search - Emergency Generator

ID	State	Company/Facility	Process Type	Throughput	Throughput Units	Primary Fuel	Permit Type[1]	Permit Date	Emission Limit (lb/MMBtu)	Avg. Period	Control Type
OH-0255	OH	AEP WATERFORD ENERGY LLC	EMERGENCY GENERATOR	1000	KW	DIESEL	D	03/29/2001	0.0007		
OH-0275	OH	PSI ENERGY-MADISON STATION	EMERGENCY DIESEL GENERATOR, 2	17.21	MMBTU/H	DIESEL FUEL	A	08/24/2004	0.0036	ROLLING 12-MONTHS	
OH-0266	OH	UNIVERSITY OF CINCINNATI	DIESEL FIRED ENGINES (2), 2 MW, 2922 BHP	19.17	MMBTU/H	DIESEL FUEL OIL	A	08/15/2002	0.012		
AZ-0046	AZ	ARIZONA CLEAN FUELS YUMA	EMERGENCY GENERATOR	10.9	MMBTU/H	NO. 2 DIESEL FUEL	A	04/14/2005	0.013		
CO-0055	CO	LAMAR LIGHT & POWER POWER PLANT	DIESEL ENGINES FOR SWITCHING, LOCOMOTIVE & FIRE PUMP	1500	HP	DIESEL	D	02/03/2006	0.016	DURATION OF TESTS	LOW SULFUR FUEL - %0.05 BY WEIGHT
LA-0231	LA	LAKE CHARLES GASIFICATION FACILITY	EMERGENCY DIESEL POWER GENERATOR ENGINES (2)	1341	HP EACH	DIESEL	A	06/22/2009	0.018	MAXIMUM (EACH)	COMPLY WITH 40 CFR 60 SUBPART IIII
OK-0070	OK	GENOVA OK I POWER PROJECT	DIESEL ENGINE, BACKUP GENERATOR	750	KW	DIESEL	A	06/13/2002	0.033		COMBUSTION CONTROL AND GOOD ENGINE DESIGN
CA-1010	CA	POWER SYSTEM ASSOCIATES/JOHNSON POWER SYSTEMS	IC ENGINE, EMERGENCY, COMPRESSION IGNITION	764	BHP	DIESEL	A	07/11/2001	0.035		
CA-1120	CA	SNOW SUMMIT, INC.	ICE: COMPRESSION IGNITION > = 175 HP	2835	2835 BHP	DIESEL	A	08/26/2003	0.039		SCR SYSTEM AND DIESEL PARTICULATE FILTER
NV-0050	NV	MGM MIRAGE	EMERGENCY GENERATORS - UNITS LX024 AND LX025 AT LUXOR	2206	HP	DIESEL OIL	A	11/30/2009	0.039		TURBOCHARGER AND GOOD COMBUSTION PRACTICES
OK-0091	OK	CARDINAL FG CO./ CARDINAL GLASS PLANT	IC ENGINES, EMERGENCY GENERATORS (2)	2000	KW	DIESEL	A	03/18/2003	0.044		ENGINE DESIGN
NJ-0036	NJ	AES RED OAK LLC	EMERGENCY GENERATOR	49	MMBTU/H	DIESEL FUEL	D	10/24/2001	0.054		LIMITED USE
NY-0101	NY	CORNELL COMBINED HEAT & POWER PROJECT	EMERGENCY DIESEL GENERATORS (2)	1000	KW	LOW SULFUR DIESEL	B	03/12/2008	0.056	1 HOUR AVG	ULTRA LOW SULFUR DIESEL AT 15 PPM S.
NY-0101	NY	CORNELL COMBINED HEAT & POWER PROJECT	EMERGENCY DIESEL GENERATORS (2)	1000	KW	LOW SULFUR DIESEL	B	03/12/2008	0.056	1 HOUR AVG	ULTRA LOW SULFUR DIESEL AT 15 PPM S
NY-0101	NY	CORNELL COMBINED HEAT & POWER PROJECT	EMERGENCY DIESEL GENERATORS (2)	1000	KW	LOW SULFUR DIESEL	B	03/12/2008	0.056	1 HOUR AVG	ULTRA LOW SULFUR DIESEL AT 15 PPM S
MI-0389	MI	KARN WEADOCK GENERATING COMPLEX	EMERGENCY GENERATOR	2000	KW	ULTRA LOW SULFUR DIESEL		12/29/2009	0.057	TEST METHOD	ENGINE DESIGN AND OPERATION. 15 PPM SULFUR FUEL.
CA-1013	CA	POWER SYSTEM ASSOCIATES/JOHNSON POWER SYSTEMS	IC ENGINE, EMERGENCY, COMPRESSION IGNITION	610	BHP	DIESEL	A	07/11/2001	0.061		
MN-0054	MN	MANKATO ENERGY CENTER	INTERNAL COMBUSTION ENGINE, LARGE	1850	HP	DIESEL FUEL		12/04/2003	0.061		GOOD COMBUSTION
WI-0207	WI	ACE ETHANOL - STANLEY	IC ENGINE, DIESEL GENERATOR SET, B70	1850	BHP		A	01/21/2004	0.061		USE OF VERY LOW SULFUR DIESEL FUEL (0.05 WT % S).
MN-0054	MN	MANKATO ENERGY CENTER	INTERNAL COMBUSTION ENGINE, LARGE	1850	HP	DIESEL FUEL		12/04/2003	0.061		GOOD COMBUSTION
IA-0064	IA	ROQUETTE AMERICA	710 HP DIESEL STARTING ENGINE	38.4	GAL/H	DIESEL	A	01/31/2003	0.069		LOW ASH FUEL, GOOD COMBUSTION PRACTICES.
NV-0047	NV	NELLIS AIR FORCE BASE	LARGE INTERNAL COMBUSTION ENGINES (>500 HP)			DIESEL OIL	A	02/26/2008	0.073		TURBOCHARGER AND AFTERCOOLER
CA-0988	CA	PACIFIC BELL	IC ENGINES	2935	HP	DIESEL FUEL	A	02/01/2003	0.087		
MN-0053	MN	FAIRBAULT ENERGY PARK	IC ENGINE, LARGE, FUEL OIL (1)	670	HP	DIESEL	A	07/15/2004	0.100	3 HOUR AVERAGE	CLEAN FUEL AND GOOD COMBUSTION.
LA-0204	LA	PLAQUEMINE PVC PLANT	LARGE EMERGENCY ENGINES			DIESEL	A	02/27/2009	0.100		GOOD COMBUSTION PRACTICES AND GASEOUS FUEL BURNING
OH-0317	OH	OHIO RIVER CLEAN FUELS, LLC	EMERGENCY GENERATOR	2922	HP	DIESEL FUEL OIL	A	11/20/2008	0.117		GOOD COMBUSTION PRACTICES AND GOOD ENGINE DESIGN
OK-0090	OK	DUKE ENERGY STEPHENS, LLC STEPHENS ENERGY	IC ENGINE, BACKUP GENERATOR, DIESEL	749	BHP	DIESEL	D	03/21/2003	0.124		COMBUSTION CONTROL AND GOOD ENGINE DESIGN
LA-0219	LA	CREOLE TRAIL LNG IMPORT TERMINAL	DIESEL EMERGENCY GENERATOR NOS. 1 & 2	2168	HP EACH	DIESEL	A	08/15/2007	0.125	HOURLY MAXIMUM	GOOD COMBUSTION PRACTICES, GOOD ENGINE DESIGN, AND USE OF LOW SULFUR AND LOW ASH DIESEL
OK-0129	OK	CHOUTEAU POWER PLANT	EMERGENCY DIESEL GENERATOR (2200 HP)	2200	HP	LOW SULFUR DIESEL	B	01/23/2009	0.129		
ID-0018	ID	LANGLEY GULCH POWER PLANT	EMERGENCY GENERATOR ENGINE	750	KW	DIESEL	A	06/25/2010	0.129		TIER 2 ENGINE-BASED,
IA-0088	IA	ADM CORN PROCESSING - CEDAR RAPIDS	EMERGENCY GENERATOR	1500	KW	DIESEL	B	06/29/2007	0.130	AVERAGE OF 3 TEST RUNS	NO SPECIFIC CONTROL TECHNOLOGY IS SPECIFED. ENGINE IS REQUIRED TO MEET LIMITS ESTABLISHED AS BACT (TIER 2 NONROAD). THIS COULD REQUIRE ANY NUMBER OF CONTROL TECHNOLOGIES AND OPERATIONAL REQ. TO MEET THE BACT STANDARD.
PA-0271	PA	MERCK & CO. WESTPOINT	MOBILE EMERGENCY GENERATOR			DIESEL	B	02/23/2007	0.139		
IA-0067	IA	WALTER SCOTT JR. ENERGY CENTER	EMERGENCY GENERATOR	97.73	GAL/H	DIESEL FUEL	B	06/17/2003	0.140		GOOD COMBUSTION PRACTICES
LA-0219	LA	CREOLE TRAIL LNG IMPORT TERMINAL	FIREWATER PUMP DIESEL ENGINE	525	HP	DIESEL	A	08/15/2007	0.210	HOURLY MAXIMUM	GOOD COMBUSTION PRACTICES, GOOD ENGINE DESIGN, AND USE OF LOW SULFUR AND LOW ASH DIESEL
MN-0071	MN	FAIRBAULT ENERGY PARK	EMERGENCY GENERATOR	1750	KW	NO. 2		06/05/2007	0.275	3 HOUR	
NV-0049	NV	HARRAH'S OPERATING COMPANY, INC.	LARGE INTERNAL COMBUSTION ENGINES (>600 HP) - UNIT HA13	1232	HP	DIESEL OIL	A	08/20/2009	0.275		THE UNIT IS EQUIPPED WITH A TURBOCHARGER.
OK-0128	OK	MID AMERICAN STEEL ROLLING MILL	Emergency Generator	1200	HP	No. 2 diesel	B	09/08/2008	0.275		
FL-0310	FL	SHADY HILLS GENERATING STATION	2.5 MW EMERGENCY GENERATOR	2.5	MW	ULTRA LOW S OIL	B	01/12/2009	0.347	NA /RECORDKEEPING	FIRING ULSO WITH A MAXIMUM SULFUR CONTENT OF 0.0015% BY WEIGHT AND A MAXIMUM HOURS OF OPERATION OF 500 HOUR/YR.
LA-0219	LA	CREOLE TRAIL LNG IMPORT TERMINAL	FIREWATER PUMP DIESEL ENGINE	660	HP	DIESEL	A	08/15/2007	0.381	HOURLY MAXIMUM	GOOD COMBUSTION PRACTICES, GOOD ENGINE DESIGN, AND USE OF LOW SULFUR AND LOW ASH DIESEL
LA-0211	LA	GARYVILLE REFINERY	EMERGENCY GENERATORS (DOCK & TANK FARM) (21-08 & 22-08)			DIESEL	D	12/27/2006	0.865	ANNUAL AVERAGE	USE OF DIESEL WITH A SULFUR CONTENT OF 15 PPMV OR LESS
AK-0061	AK	SNAKE RIVER POWER PLANT	WARTSILA 12V32B DIESEL ELECTRIC GENERATOR	5211	KW	DIESEL FUEL	B	11/05/2004	11.59	3-HOUR @ 100% LOAD	GOOD COMBUSTION PRACTICES
*VA-0305	VA	INGENCO K&O FACILITY	ELECTRIC GENERATION	550	HHP	DISTILLATE OIL	A	09/26/2007	18.91		GOOD COMBUSTIONS PRACTICES AND CONTINUOUS MONITORING DEVICES
*VA-0305	VA	INGENCO K&O FACILITY	ELECTRIC GENERATION	550	HHP	DISTILLATE OIL	A	09/26/2007	18.91		GOOD COMBUSTIONS PRACTICES AND CONTINUOUS MONITORING DEVICES

1. Permit types: A = New/Greenfield facility, B = Adding new process to an existing facility, C = Modifying an existing process at an existing facility, D = Both B & C.

Table D-20. VOC Best Available Control Technology RBLC Search - Emergency Generator

ID	State	Company/Facility	Process Type	Throughput	Throughput Units	Primary Fuel	Permit Type[1]	Permit Date	Emission Limit (lb/MMBtu)	Avg. Period	Control Type
OH-0255	OH	AEP WATERFORD ENERGY LLC	EMERGENCY GENERATOR	1000	KW	DIESEL	D	03/29/2001	0.001		
LA-0219	LA	CREOLE TRAIL LNG IMPORT TERMINAL	FIREWATER PUMP DIESEL ENGINE	660	HP	DIESEL	A	08/15/2007	0.02	HOURLY MAXIMUM	GOOD COMBUSTION PRACTICES AND GOOD ENGINE DESIGN
CA-1010	CA	POWER SYSTEM ASSOCIATES/JOHNSON POWER SYSTEMS	IC ENGINE, EMERGENCY, COMPRESSION IGNITION	764	BHP	DIESEL	A	07/11/2001	0.03		
LA-0194	LA	SABINE PASS LNG TERMINAL	FIREWATER PUMP DIESEL ENGINES 1-3	660	HP EACH	DIESEL	A	11/24/2004	0.04	HOURLY MAXIMUM	GOOD COMBUSTION PRACTICES
OH-0266	OH	UNIVERSITY OF CINCINNATI	DIESEL FIRED ENGINES (2), 2 MW, 2922 BHP	19.17	MMBTU/H	DIESEL FUEL OIL	A	08/15/2002	0.05		
CA-1012	CA	POWER SYSTEM ASSOCIATES/JOHNSON POWER SYSTEMS	IC ENGINES, EMERGENCY, COMPRESSION IGNITION	685	BHP	DIESEL	A	07/11/2001	0.06		
CA-1013	CA	POWER SYSTEM ASSOCIATES/JOHNSON POWER SYSTEMS	IC ENGINE, EMERGENCY, COMPRESSION IGNITION	610	BHP	DIESEL	A	07/11/2001	0.06		
IA-0095	IA	TATE & LYLE INDGREDIENTS AMERICAS, INC.	FIRE PUMP ENGINE	575	HP	DIESEL	A	09/19/2008	0.06	AVERAGE OF THREE STACK TEST RUNS	
LA-0219	LA	CREOLE TRAIL LNG IMPORT TERMINAL	FIREWATER PUMP DIESEL ENGINE	525	HP	DIESEL	A	08/15/2007	0.07	HOURLY MAXIMUM	GOOD COMBUSTION PRACTICES AND GOOD ENGINE DESIGN
IA-0067	IA	WALTER SCOTT JR. ENERGY CENTER	EMERGENCY GENERATOR	97.73	GAL/H	DIESEL FUEL	B	06/17/2003	0.09		GOOD COMBUSTION PRACTICES
OH-0275	OH	PSI ENERGY-MADISON STATION	EMERGENCY DIESEL GENERATOR, 2	17.21	MMBTU/H	DIESEL FUEL	A	08/24/2004	0.09		
MN-0053	MN	FAIRBAULT ENERGY PARK	IC ENGINE, LARGE, FUEL OIL (1)	670	HP	DIESEL	A	07/15/2004	0.1	3 HOUR AVERAGE	GOOD COMBUSTION.
MN-0054	MN	MANKATO ENERGY CENTER	INTERNAL COMBUSTION ENGINE, LARGE	1850	HP	DIESEL FUEL		12/04/2003	0.10		GOOD COMBUSTION
WI-0207	WI	ACE ETHANOL - STANLEY	IC ENGINE, DIESEL GENERATOR SET, B70	1850	BHP		A	01/21/2004	0.10		LIMITED OPERATION, DESIGN
NV-0050	NV	MGM MIRAGE	EMERGENCY GENERATORS - UNITS LX024 AND LX025 AT LUXOR	2206	HP	DIESEL OIL	A	11/30/2009	0.12		TURBOCHARGER AND GOOD COMBUSTION PRACTICES
IA-0095	IA	TATE & LYLE INDGREDIENTS AMERICAS, INC.	EMERGENCY GENERATOR	700	KW	DIESEL	A	09/19/2008	0.13	AVERAGE OF THREE STACK TEST RUNS	
NV-0047	NV	NELLIS AIR FORCE BASE	LARGE INTERNAL COMBUSTION ENGINES (>500 HP)			DIESEL OIL	A	02/26/2008	0.17		TURBOCHARGER AND AFTERCOOLER
OH-0317	OH	OHIO RIVER CLEAN FUELS, LLC	EMERGENCY GENERATOR	2922	HP	DIESEL FUEL OIL	A	11/20/2008	0.19		GOOD COMBUSTION PRACTICES AND GOOD ENGINE DESIGN
NJ-0036	NJ	AES RED OAK LLC	EMERGENCY GENERATOR	49	MMBTU/H	DIESEL FUEL	D	10/24/2001	0.25		GOOD COMBUSTION
SC-0064	SC	SCE&G - JASPER COUNTY GENERATING FACILITY	GENERATOR, EMERGENCY,DIESEL FUEL	2000	KW	DIESEL	A	05/23/2002	0.25		
OK-0128	OK	MID AMERICAN STEEL ROLLING MILL	Emergency Generator	1200	HP	No. 2 diesel	B	09/08/2008	0.25		
IA-0088	IA	ADM CORN PROCESSING - CEDAR RAPIDS	EMERGENCY GENERATOR	1500	KW	DIESEL	B	06/29/2007	0.26	AVERAGE OF 3 TEST RUNS	NO SPECIFIC CONTROL TECHNOLOGY IS SPECIFED. ENGINE IS REQUIRED TO MEET LIMITS ESTABLISHED AS BACT (TIER 2 NONROAD). THIS COULD REQUIRE ANY NUMBER OF CONTROL TECHNOLOGIES AND OPERATIONAL REQ. TO MEET THE BACT STANDARD.
WV-0023	WV	MAIDSVILLE	EMERGENCY GENERATOR	1801	HP	DIESEL	A	03/02/2004	0.26		GOOD COMBUSTION PRACTICES
MN-0071	MN	FAIRBAULT ENERGY PARK	EMERGENCY GENERATOR	1750	KW	NO. 2		06/05/2007	0.28	3 HOUR AVERAGE	
NV-0049	NV	HARRAH'S OPERATING COMPANY, INC.	LARGE INTERNAL COMBUSTION ENGINES (>600 HP) - UNIT HA13	1232	HP	DIESEL OIL	A	08/20/2009	0.28		THE UNIT IS EQUIPPED WITH A TURBOCHARGER.
OK-0072	OK	REDBUD POWER PLT	DIESEL ENGINE, EMERGENCY GENERATOR	1818	HP	DIESEL FUEL	D	05/06/2002	0.28		ENGINE DESIGN
OK-0129	OK	CHOUTEAU POWER PLANT	EMERGENCY DIESEL GENERATOR (2200 HP)	2200	HP	LOW SULFUR DIESEL	B	01/23/2009	0.28		GOOD COMBUSTION
PA-0271	PA	MERCK & CO. WESTPOINT	MOBILE EMERGENCY GENERATOR			DIESEL	B	02/23/2007	0.28		
LA-0219	LA	CREOLE TRAIL LNG IMPORT TERMINAL	DIESEL EMERGENCY GENERATOR NOS. 1 & 2	2168	HP EACH	DIESEL	A	08/15/2007	0.30	HOURLY MAXIMUM	GOOD COMBUSTION PRACTICES AND GOOD ENGINE DESIGN
OK-0091	OK	CARDINAL FG CO./ CARDINAL GLASS PLANT	IC ENGINES, EMERGENCY GENERATORS (2)	2000	KW	DIESEL	A	03/18/2003	0.32		ENGINE DESIGN AND LIMIT ON HOURS OF OPERATION (<500 H/YR)
VA-0276	VA	INGENCO - CHARLES CITY PLANT	IC ENGINES, (48)	550	HP	FUEL OIL	A	06/20/2003	0.4		GOOD COMBUSTION PRACTICES.
OH-0254	OH	DUKE ENERGY WASHINGTON COUNTY LLC	EMERGENCY DIESEL-FIRED GENERATOR	600	KW	DIESEL	D	08/14/2003	0.86		LOW SULFUR FUEL, COMBUSTION CONTROL
CA-0988	CA	PACIFIC BELL	IC ENGINES	2935	HP	DIESEL FUEL	A	02/01/2003	0.87		
OK-0090	OK	DUKE ENERGY STEPHENS, LLC STEPHENS ENERGY	IC ENGINE, BACKUP GENERATOR, DIESEL	749	BHP	DIESEL	D	03/21/2003	0.89		BACT IS GOOD ENGINE DESIGN
LA-0122	LA	MANSFIELD MILL	ADMINISTRATION BUILDING DIESEL GENERATOR	587	HP	DIESEL	D	08/14/2001	0.94		PREVENTATIVE MAINTENANCE
AR-0051	AR	DUKE ENERGY-JACKSON FACILITY	GENERATOR, DIESEL-FIRED	671	HP	DIESEL FUEL	D	04/01/2002	0.95		GOOD OPERATING PRACTICE
LA-0122	LA	MANSFIELD MILL	CATERPILLAR BACK-UP DIESEL AIR COMPRESSORS, 2	775	HP EACH	DIESEL FUEL	D	08/14/2001	0.96	EACH	PREVENTATIVE MAINTENANCE
LA-0122	LA	MANSFIELD MILL	AUXILIARY DIESEL GENERATORS NO.1 & NO.2	1100	HP EACH	DIESEL FUEL	D	08/14/2001	0.96	EACH	PREVENTATIVE MAINTENANCE
TX-0407	TX	STERNE ELECTRIC GENERATING FACILITY	EMERGENCY GENERATOR	1350	HP	DIESEL	A	12/06/2002	0.97		
LA-0211	LA	GARYVILLE REFINERY	EMERGENCY GENERATORS (DOCK & TANK FARM) (21-08 & 22-08)			DIESEL	D	12/27/2006	0.98	ANNUAL AVERAGE	USE OF DIESEL WITH A SULFUR CONTENT OF 15 PPMV OR LESS
AR-0094	AR	JOHN W. TURK JR. POWER PLANT	EMERGENCY GENERATOR AND FIRE PUMP ENGINE				A	11/05/2008	4.14	3 HOUR	GOOD COMBUSTION
ID-0018	ID	LANGLEY GULCH POWER PLANT	EMERGENCY GENERATOR ENGINE	750	KW	DIESEL	A	06/25/2010	4.14	NOX+NMHC	TIER 2 ENGINE-BASED, GOOD COMBUSTION PRACTICES (GCP)
IA-0084	IA	ADM POLYMERS	EMERGENCY GENERATOR	74.3	GAL/H	DIESEL FUEL	B	11/30/2006	4.16	AVERAGE OF THREE (3) 1-H TEST RUNS	GOOD COMBUSTION PRACTICES
*VA-0305	VA	INGENCO K&O FACILITY	ELECTRIC GENERATION	550	HHP	DISTILLATE OIL	A	09/26/2007	25.21		GOOD COMBUSTIONS PRACTICES AND CONTINUOUS MONITORING DEVICES

1. Permit types: A = New/Greenfield facility, B = Adding new process to an existing facility, C = Modifying an existing process at an existing facility, D = Both B & C.

Table D-21. PM/PM_{10}/$PM_{2.5}$ - Best Available Control Technology RBLC Search - Material Handling

RBLC ID	State	Company/Facility	Database	Process Type	Permit Type	Permit Date	Pollutant	Limit (gr/dscf)	Controls / Type
GA-0074	GA	DRY BRANCH KAOLIN CO.	RBLC	SILOS (5)	D	11/6/1995	Particulate Matter (PM)	0.0008	BAGHOUSE
GA-0074	GA	DRY BRANCH KAOLIN CO.	RBLC	TRUCK LOADING	D	11/6/1995	Particulate Matter (PM)	0.0008	BAGHOUSE
GA-0074	GA	DRY BRANCH KAOLIN CO.	RBLC	RAILCAR LOADING	D	11/6/1995	Particulate Matter (PM)	0.0008	BAGHOUSE
GA-0074	GA	DRY BRANCH KAOLIN CO.	RBLC	BIN VENTS (3)	D	11/6/1995	Particulate Matter (PM)	0.0008	BAGHOUSE
*WI-0252	WI	SPECIALTY MINERALS INC. - SUPERIOR	RBLC	P10 - LIME SILO	A	7/22/2010	Particulate matter, filterable < 2.5 µ (FPM2.5)	0.001	PNEUMATIC CONVEYING, TOTAL ENCLOSURE, BIN VENT FABRIC FILTER
GA-0132	GA	YELLOW PINE ENERGY COMPANY, LLC	RBLC	FUEL PROCESS BUILDING 1	A	12/3/2008	Particulate matter, fugitive	0.0014	FUEL PROCESS BUILDING 1 - FABRIC FILTER, WATER SPRAYS, AND ENCLOSURE; FUEL STORAGE SILO - FABRIC FILTER AND ENCLOSURE; FLY ASH SILO - ENCLOSURES AND CLOSED VENT SYSTEM; TRIPPER DECK DAY SILOS 1-5 - FABRIC FILTERS AND ENCLOSURES.
KY-0079	KY	KENTUCKY MOUNTAIN POWER, LLC	RBLC	MATERIAL HANDLING, LIMESTONE PREP SYSTEM	A	5/4/2001	Particulate Matter (PM)	0.0014	ENCLOSURE AND BAGHOUSE FOR TRUCK DUMP AND FEED & CONVEY POINTS, BAGHOUSE FOR SURGE BINS AND SILOS
WY-0038	WY	WOLD TRONA CO.	RBLC	BENETRON ORE UPGRADE FACILITY 2 EA	D	5/2/1995	Particulate Matter (PM)	0.0025	ELECTROSTATIC PRECIPITATOR, 4 IN PARALLEL
CA-1156	CA	MISSION READY MIX - GOLETA	RBLC	CONCRETE BATCH PLANT: >= 5 CUBIC YARD PER BATCH	A	9/29/2006	Particulate Matter (PM)	0.003	BAGHOUSE AND VENT FILTERS (3X)
CA-1156	CA	MISSION READY MIX - GOLETA	RBLC	CONCRETE BATCH PLANT: >= 5 CUBIC YARD PER BATCH	A	9/29/2006	Particulate matter, filterable < 10 µ (FPM10)	0.003	BAGHOUSE AND VENT FILTERS (3X)
AL-0220	AL	CHEMICAL LIME COMPANY - O"NEAL PLANT	RBLC	RAW MATERIALS HANDLING	B	3/23/2005	Particulate Matter (PM)	0.005	
IA-0086	IA	UNIVERSITY OF NORTHERN IOWA	RBLC	#4 LIMESTONE SYSTEM - SILO	C	5/3/2007	Particulate Matter (PM)	0.005	BAGHOUSE
IA-0086	IA	UNIVERSITY OF NORTHERN IOWA	RBLC	#4 LIMESTONE SYSTEM - SILO	C	5/3/2007	Particulate matter, filterable < 10 µ (FPM10)	0.005	BAGHOUSE
IA-0095	IA	TATE & LYLE INDGREDIENTS AMERICAS, INC.	RBLC	LIME SILO	A	9/19/2008	Particulate matter, filterable < 10 µ (FPM10)	0.005	DUST COLLECTOR
IA-0095	IA	TATE & LYLE INDGREDIENTS AMERICAS, INC.	RBLC	LIME SILO	A	9/19/2008	Particulate Matter (PM)	0.005	DUST COLLECTOR
KY-0100	KY	J.K. SMITH GENERATING STATION	RBLC	LIME SILO STORAGES	A	4/9/2010	Particulate matter, filterable < 10 µ (FPM10)	0.005	FABRIC FILTERS
KY-0100	KY	J.K. SMITH GENERATING STATION	RBLC	LIMESTONE STORAGE SILOS	A	4/9/2010	Particulate matter, filterable < 10 µ (FPM10)	0.005	FABRIC FILTER
ND-0021	ND	GASCOYNE GENERATING STATION	RBLC	MATERIALS HANDLING	A	6/3/2005	Particulate Matter (PM)	0.005	BAGHOUSES
ND-0024	ND	SPIRITWOOD STATION	RBLC	MATERIALS HANDLING	A	9/14/2007	Particulate matter, filterable (FPM)	0.005	BAGHOUSE
OH-0321	OH	MARTIN MARIETTA MATERIALS	RBLC	LIME LOAD-OUT, SCREENING, TRANSFER, STORAGE	B	11/13/2008	Particulate matter, filterable < 10 µ (FPM10)	0.005	BAGHOUSES (2) WHICH SHALL ACHIEVE 99.5% CAPTURE EFFICIENCY
*WI-0252	WI	SPECIALTY MINERALS INC. - SUPERIOR	RBLC	P10 - LIME SILO	A	7/22/2010	Particulate Matter (PM)	0.005	PNEUMATIC CONVEYING, TOTAL ENCLOSURE AND BIN VENT FABRIC FILTER.
FL-0318	FL	HIGHLANDS ETHANOL FACILITY	RBLC	Miscellaneous Storage Silos	A	12/10/2009	Particulate matter, total (TPM)	0.005	Fabric filters baghouses (bin vent filters) will be used to control PM emissions from all the silos. All silos will have stacks with design diameters of 1.5 feet with design flow rates of 2,500 ACFM.
IA-0089	IA	HOMELAND ENERGY SOLUTIONS, LLC, PN 06-672	RBLC	SULFUR STORAGE AND HANDLING, S18 (07-A-963P)	A	8/8/2007	Particulate Matter (PM)	0.005	BAGHOUSE
IA-0089	IA	HOMELAND ENERGY SOLUTIONS, LLC, PN 06-672	RBLC	SULFUR STORAGE AND HANDLING, S18 (07-A-963P)	A	8/8/2007	Particulate matter, filterable < 10 µ (FPM10)	0.005	BAGHOUSE
OH-0321	OH	MARTIN MARIETTA MATERIALS	RBLC	PRODUCT TRANSFER, PROCESSED STONE, CONVEYING AT KILN	B	11/13/2008	Particulate matter, filterable < 10 µ (FPM10)	0.007	BAGHOUSE
AZ-0051	AZ	DRAKE	RBLC	FINISH MILLS, STORAGE BINS, BULK LOADING AND UNLOADING, CONVEYOR TRANSFER ACTIVTIES AND MISCELLANEOUS MATERIAL TRANSFER ACTIVTIES	A	4/12/2006	Particulate matter, filterable (FPM)	0.008	BAGHOUSES
FL-0139	FL	SUWANNEE AMERICAN CEMENT COMPANY, INC.	RBLC	BAGHOUSE, MATERIAL HANDLING & STORAGE SILO	A	6/1/2000	Particulate matter, filterable < 10 µ (FPM10)	0.0085	BAGHOUSE
IA-0070	IA	LEHIGH CEMENT COMPANY - MASON CITY PLANT	RBLC	SILO WITHDRAWAL	D	12/11/2003	Particulate matter, filterable < 10 µ (FPM10)	0.009	BAGHOUSE.
MT-0022	MT	BULL MOUNTAIN, NO. 1, LLC - ROUNDUP POWER P	RBLC	MATERIAL TRANSFER, LIME HANDLING TRANSFER POINTS	A	7/21/2003	Particulate matter, filterable < 10 µ (FPM10)	0.01	PNEUMATIC TRANSFERS AND BAGHOUSE
MT-0027	MT	HARDIN GENERATOR PROJECT	RBLC	MATERIAL TRANSFER, LIME HANDLING TRANSFER POINTS	A	6/11/2002	Particulate matter, filterable < 10 µ (FPM10)	0.01	DUST SUPPRESSION SYSTEMS AND ENCLOSURES, BAGHOUSE
OH-0321	OH	MARTIN MARIETTA MATERIALS	RBLC	DUST LOAD-OUT SYSTEM	B	11/13/2008	Particulate matter, filterable < 10 µ (FPM10)	0.01	BAGHOUSE WITH 99.5% CAPTURE EFFICIENCY. MECHANICAL ENCLOSURED FOR CONVEYING EQUIPMENT
WV-0024	WV	WESTERN GREENBRIER CO-GENERATION, LLC	RBLC	LIMESTONE HANDLING	A	4/26/2006	Particulate Matter (PM)	0.01	FABRIC FILTERS
AR-0094	AR	JOHN W. TURK JR. POWER PLANT	RBLC	DUST COLLECTORS	A	11/5/2008	Particulate Matter (PM)	0.01	FABRIC FILTER
*FL-0322	FL	SWEET SORGHUM-TO-ETHANOL ADVANCED BIORI	RBLC	Miscellaneous Storage Silos	A	12/23/2010	Particulate matter, total (TPM)	0.01	Baghouse.
AR-0082	AR	ARKANSAS LIME COMPANY	RBLC	LIME STORAGE SILO DUST COLLECTORS, SN-36Q AND SN-37Q	A	8/30/2005	Particulate matter, filterable < 10 µ (FPM10)	0.015	DUST COLLECTOR
AR-0082	AR	ARKANSAS LIME COMPANY	RBLC	LIME LOADOUT DUST COLLECTOR, SN-38Q AND SN-39Q	A	8/30/2005	Particulate matter, filterable < 10 µ (FPM10)	0.015	DUST COLLECTOR
GA-0129	GA	C.E. MINERALS PLANT	RBLC	BAUXITE GRINDING CIRCUIT	C	3/9/2005	Particulate matter, filterable < 10 µ (FPM10)	0.016	BAGHOUSE
	GA	CARBO CERAMICS, INC.	PSD PERMIT	BAGHOUSES AND BIN VENTS			Particulate Matter (PM)	0.02	BAGHOUSE AND BIN VENT
FL-0168	FL	MCKAY BAY REFUSE-TO-ENERGY FACILITY	RBLC	MUNICIPAL WASTE COMBUSTOR, MATERIAL STORAGE SILOS	D	6/15/2000	Particulate Matter (PM)	0.02	SPRAY SCRUBBER FOR ASH AND SCALPER BUIDINGS. VENT FILTERS FOR LIME AND CARBON SILOS. NO CHANGES IN EMISSION LIMITS.
OH-0231	OH	TOLEDO EDISON CO. - BAYSHORE PLANT	RBLC	LIMESTONE CRUSHING, SIZING, AND CONVEYING	A	7/31/2003	Particulate Matter (PM)	0.02	BAGHOUSE
KY-0084	KY	THOROUGHBRED GENERATING STATION	RBLC	FGD REAGENT PREP HANDLING, LIME	A	10/11/2002	Particulate Matter (PM)	0.02	ENCLOSURES AND FILTERS
SC-0104	SC	SANTEE COOPER CROSS GENERATING STATION	RBLC	LIMESTONE HANDLING	D	2/5/2004	Particulate Matter (PM)	0.022	BAGHOUSE
OK-0111	OK	MUSKOGEE PORCELAIN FLOOR TILE PLT	RBLC	MATERIALS HANDLING	0	10/14/2005	Particulate matter, filterable < 10 µ (FPM10)	0.077	BAGHOUSE
WY-0064	WY	DRY FORK STATION	RBLC	MATERIAL HANDLING SOURCES (COAL PREP)	A	10/15/2007	Particulate matter, filterable < 10 µ (FPM10)	0.08	ENCLOSED SYSTEM WITH VENTS FEEDING FABRIC FILTERS
LA-0231	LA	LAKE CHARLES GASIFICATION FACILITY	RBLC	COKE HANDLING SYSTEMS (2)	A	6/22/2009	Particulate matter, total < 10 µ (TPM10)	0.08	FABRIC FILTERS
OR-0036	OR	DURKEE FACILITY	RBLC	AIR SLIDE TO BLEND SILOS	A	2/26/1998	Particulate Matter (PM)	0.1	BAGHOUSE
WI-0233	WI	CLM - SUPERIOR	RBLC	SMALL SILO TRUCK LOADING (P53)	A	8/16/2006	Particulate Matter (PM)	0.18	FABRIC FILTER BAGHOUSE, TOTAL ENCLOSURE OF THE PROCESS OPERATIONS, USE OF A VACUUM RING FOR TRUCK FILLING

Table D-22. NO_X Control Summary

Emission Unit	Control Technology	Efficiency	Emissions tpy	tpy (reduced)	$/year[1]	Annualized Capital Cost	Evaluation
Pelletizer	SCR	80%	9.86	7.88	$78,840	$33,874	May be cost feasible
	SNCR	70%	9.86	6.90	$68,985	$24,600	May be cost feasible
Boiler	SCR	80%	2.15	1.72	$17,170	$4,426	May be cost feasible
	SNCR	70%	2.15	1.50	$15,023	$3,214	May be cost feasible

1. Based on $10,000/ton * tpy (reduced) = $ / yr. $10,000/yr is assumed to be the threshold above which the purchase of a control technology would be cost prohibitive.

Table D-23. CO Control Summary

Emission Unit	Control Technology	Efficiency	Emissions tpy	tpy (reduced)	$/year[1]	Annualized Capital Cost	Evaluation
Calciner/Kiln	RTO	98%	243.08	238.22	$2,382,184	$630,326	May be cost feasible
	Oxidation Catalyst w/reheat	95%	243.08	230.93	$2,309,260	$403,409	May be cost feasible
Pelletizer	RTO	98%	60.12	58.91	$589,132	$1,427,319	Cost prohibitive
	Oxidation Catalyst w/reheat	95%	60.12	57.11	$571,097	$913,484	Cost prohibitive
Boiler	RTO	98%	3.61	3.5335	$35,335	$107,034	Cost prohibitive
	Oxidation Catalyst w/reheat	95%	3.61	3.4253	$34,253	$68,502	Cost prohibitive

1. Based on $10,000/ton * tpy (reduced) = $ / yr. $10,000/yr is assumed to be the threshold above which the purchase of a control technology would be cost prohibitive.

Table D-24. VOC Control Summary

Emission Unit	Control Technology	Efficiency	Emissions tpy	tpy (reduced)	$/year[1]	Annualized Capital Cost	Evaluation
Calciner/Kiln	RTO	98%	2.36	2.31	$23,128	$630,326	Cost prohibitive
	Oxidation Catalyst w/reheat	95%	2.36	2.24	$22,420	$403,409	Cost prohibitive
Pelletizer	RTO	98%	52	50.57	$505,680	$1,427,319	Cost prohibitive
	Oxidation Catalyst w/reheat	95%	50	47.31	$473,106	$913,484	Cost prohibitive
Boiler	RTO	98%	0.24	0.2314	$2,314	$193,768	Cost prohibitive
	Oxidation Catalyst w/reheat	95%	0.24	0.2243	$2,243	$68,502	Cost prohibitive

1. Based on $10,000/ton * tpy (reduced) = $ / yr. $10,000/yr is assumed to be the threshold above which the purchase of a control technology would be cost prohibitive.

Table D-25. Potential Control Summary

Emission Unit	Pollutant	Current Potential Emissions	Control Basis	Future Design Controlled Emissions
Calciner/Kiln	CO	2.2 lb/ton	RTO	0.04 lb/ton
	CO	2.2 lb/ton	Oxidation Catalyst w/reheat	0.11 lb/ton
	VOC	0.006 lb/MMBtu	RTO	1.10E-04 lb/MMBtu
	VOC	0.006 lb/MMBtu	Oxidation Catalyst w/reheat	2.75E-04 lb/MMBtu
Pelletizer (each)	NO_X	0.03 lb/MMBtu	SCR	0.006 lb/MMBtu
	NO_X	0.03 lb/MMBtu	SNCR	0.009 lb/MMBtu
	CO	0.183 lb/MMBtu	RTO	0.004 lb/MMBtu
	CO	0.183 lb/MMBtu	Oxidation Catalyst w/reheat	0.009 lb/MMBtu
	VOC	11.37 lb/hr	RTO	0.23 lb/hr
	VOC	11.37 lb/hr	Oxidation Catalyst w/reheat	0.57 lb/hr
Boiler	NO_X	0.05 lb/MMBtu	SCR	0.010 lb/MMBtu
	NO_X	0.05 lb/MMBtu	SNCR	0.015 lb/MMBtu
	CO	0.084 lb/MMBtu	RTO	0.002 lb/MMBtu
	CO	0.084 lb/MMBtu	Oxidation Catalyst w/reheat	0.004 lb/MMBtu
	VOC	0.006 lb/MMBtu	RTO	1.10E-04 lb/MMBtu
	VOC	0.006 lb/MMBtu	Oxidation Catalyst w/reheat	2.75E-04 lb/MMBtu

Kiln Heat Input Capacity	49.3	MMBtu/hr		
Kiln Feed Rate	46,688	lb/hr	204,493	tpy
Pelletizer Heat Input Capacity	75	MMBtu/hr		
Boiler Heat Input Capacity	9.8	MMBtu/hr		

Table D-26. Cost Summary

Emission Unit	Pollutant	Technology	Control Efficiency* (%)	Baseline Emissions (tpy)	Pollutant Removed (tpy)	Operating Cost ($/ton removed)	Annual Cost ($/year)
Calciner/Kiln	CO	RTO	98%	243.08	238.22	21,479	$ 5,116,651
	CO	Oxidation Catalyst w/reheat	95%	243.08	230.93	13,999	$ 3,232,812
	VOC	RTO	98%	2.36	2.31	2,212,319	$ 5,116,651
	VOC	Oxidation Catalyst w/reheat	95%	2.36	2.24	1,441,932	$ 3,232,812
Pelletizer (each)	NO_X	SCR	80%	9.86	7.88	$ 22,524	$ 177,576
	NO_X	SNCR	70%	9.86	6.90	$ 25,270	$ 174,323
	CO	RTO	98%	60.12	58.91	$ 201,400	$ 11,865,119
	CO	Oxidation Catalyst w/reheat	95%	60.12	57.11	$ 145,677	$ 8,319,593
	VOC	RTO	98%	51.60	50.57	$ 243,115	$ 12,293,830
	VOC	Oxidation Catalyst w/reheat	95%	49.80	47.31	$ 175,851	$ 8,319,593
Boiler	NO_X	SCR	80%	2.15	1.72	$ 13,205	$ 22,672
	NO_X	SNCR	70%	2.15	1.50	$ 15,672	$ 23,544
	CO	RTO	98%	3.61	3.53	$ 251,760	$ 889,596
	CO	Oxidation Catalyst w/reheat	95%	3.61	3.43	$ 143,676	$ 492,139
	VOC	RTO	98%	0.24	0.23	$ 8,156,023	$ 1,886,980
	VOC	Oxidation Catalyst w/reheat	95%	0.24	0.22	$ 2,194,326	$ 492,139

Table D-27. Cost Analysis Supporting Information for SCR

Parameter	Pelletizer	Units	Note(s)	Boiler	Units	Note(s)
Maximum Heat Capacity	75	MMBtu/hr	1	10	MMBtu/hr	1
Potential Inlet NO_X Emissions	0.03	lb/MMBtu	1	0.05	lb/MMft^3	1
Potential Emissions NO_X	9.86	tpy	1	2.15	tpy	1
Removal Efficiency	80	%	2	80	%	2
Pollutant Removed	7.9	tpy	3	1.7	tpy	3
SCR Inlet Airflow	114,018	acfm	4	10,882	acfm	4
SCR Inlet Temperature	200	° F	4	380	° F	4
Ammonia Slip Allowed	2	ppm	5	2	ppm	5
Volume of Catalyst	2,019	ft^3	6	132	ft^3	6
Cross-Sectional Area of Catalyst	119	ft^2	7	11	ft^2	7
Catalyst Layers	6	layers	8	4	layers	8
Layer Height	3.8	ft	9	3.9	ft	9
SCR Reactor Height	74	ft	10	53	ft	10
Actual Stoichiometric Ratio (Ammonia)	1.05	n/a	11	1.05	n/a	11
Mass Flow Rate of Reagent	0.70	lb/hr	12	0.15	lb/hr	12
Reagent Consumption at Stored Concentration	0.49	gal/hr	13	0.11	gal/hr	13
Reagent Storage Capacity	165	gal	14	36	gal	14
Concentration of Stored Reagent Solution	19	% Reagent	15	19	% Reagent	15
Pressure Drop Across the SCR and Ductwork	7.0	inches of H_2O	16	5.5	inches of H_2O	16
Electricity Usage	28	kWhr	17	3	kWhr	17
Catalyst Cost, Initial	330.88	\$/ft^3	5	330.88	\$/ft^3	5
Catalyst Cost, Replacement	399.81	\$/ft^3	5	399.81	\$/ft^3	5
19% Ammonia Solution Cost	0.44	\$/lb	5	0.44	\$/lb	5
Electricity Cost	0.060	\$/kW-hr	18	0.060	\$/kW-hr	18
SCR Equipment Life	20	years	19	20	years	19
Interest Rate	7.0	%	19	7.0	%	19
1998 \$ (December)	163.9	n/a	20	163.9	n/a	20
1999 \$	166.6	n/a	20	166.6	n/a	20
2004 \$	188.9	n/a	20	188.9	n/a	20
2011 \$ (May)	226.0	n/a	20	226.0	n/a	20

1. Potential inlet emissions based on maximum capacity and emissions.
2. Assumed efficiency based on EPA's Air Pollution Control Technology Fact Sheet: http://www.epa.gov/ttn/catc/dir1/fscr.pdf
3. Pollutant Removed (tpy) = (Removal Efficiency, %) × (Potential Emissions, tpy).
4. Values based on stack outlet data.
5. Based on example problem in OAQPS Manual, Section 4.2, Chapter 2, page 2-50.
6. Volume of catalyst calculated using Equation 2.19 in OAQPS Manual, Section 4.2, Chapter 2, page 2-36.
7. Cross-sectional area of catalyst calculated using Equation 2.25 in OAQPS Manual, Section 4.2, Chapter 2, page 2-37.
8. Number of catalyst layers calculated using Equations 2.28 and 2.30 in OAQPS Manual, Section 4.2, Chapter 2, pages 2-38 and 2-39. One empty layer was assumed.
9. Height of each catalyst layer calculated using Equation 2.29 in OAQPS Manual, Section 4.2, Chapter 2, page 2-38.
10. Height of the entire SCR reactor calculated using Equation 2.31 in OAQPS Manual, Section 4.2, Chapter 2, page 2-39.
11. Actual Stoichiometric Ratio for ammonia is the typical SCR value per OAQPS Manual, Section 4.2, Chapter 2, page 2-33.
12. Mass of reagent calculated based on Equation 2.32 in OAQPS Manual, Section 4.2, Chapter 2, page 2-39.
13. Reagent Consumption calculated based on Equations 2.33 and 2.34 in OAQPS Manual, Section 4.2, Chapter 2, pages 2-39 and 2-40.
14. Reagent storage capacity based on 14 days: Storage capacity (gal) = (Reagent Consumption, gal/hr) × (24 hr/day) × (14 days).
15. Concentration based on low end of range provided OAQPS Manual, Section 4.2, Chapter 2, page 2-23.
16. Pressure drop is typically 2-3 inches for the ductwork and 0.75 to 1 inches for each catalyst layer, per OAQPS Manual, Section 4.2, Chapter 2, page 2-46.
17. Electricity usage requirement based on equation 2.48 of OAQPS Manual, Section 4.2, Chapter 2, page 2-46.
18. Cost based on estimated site-specific utility rate.
19. Based on example problem in OAQPS Manual, Section 4.2, Chapter 2, page 2-50.
20. Values based on U.S. Historical Consumer Price Index: ftp://ftp.bls.gov/pub/special.requests/cpi/cpiai.txt.

Table D-28. Cost Analysis for SCR

Capital Cost	**Pelletizer**	**Boiler**	**OAQPS Notation**[1]
Purchased Equipment Costs			
Total Equipment and Instrumentation Cost[2]	358,863	46,891	A
Instrumentation[3]	35,886	4,689	0.10 × A
Sales Tax[3]	10,766	1,407	0.03 × A
Freight[3]	17,943	2,345	0.05 × A
Total Purchased Equipment Costs	*423,458*	*55,332*	*B = 1.18 × A*
Direct Installation Costs [4]			
Foundations and Supports	42,346	5,533	0.10 × B
Handling and Erection	169,383	22,133	0.40 × B
Electrical	16,938	2,213	0.04 × B
Piping	8,469	1,107	0.02 × B
Insulation	4,235	553	0.01 × B
Painting	4,235	553	0.01 × B
Site Preparation (Site Specific)	25,407	3,320	0.06 × B
Total Direct Installation Costs	*271,013*	*35,412*	*C = 0.64 × B*
Indirect Installation Costs [5]			
General Facilities	34,724	4,537	0.05 × (B + C)
Engineering and Home Office Fees	69,447	9,074	0.10 × (B + C)
Process Contingencies	34,724	4,537	0.05 × (B + C)
Total Indirect Installation Costs	*138,894*	*18,149*	*D = 0.20 × (B + C)*
Project Contingency[5]	125,005	16,334	E = 0.15 × (B + C + D)
Total Plant Cost[5]	958,371	125,227	F = B + C + D + E
Allowance for Funds During Construction[6]	0	0	G
Royalty Allowance[6]	0	0	H
Preproduction Costs	19,167	2,505	I = 0.02 × (F + G)
Inventory Capital[7]	73	16	J
Initial Catalyst and Chemicals[6]	0	0	K
Total Capital Investment	**977,611**	**127,747**	**TCI = F + G + H + I + J + K**

Operating Cost	**Pelletizer**	**Boiler**	**OAQPS Notation**
Direct Annual Costs			
Operating and Supervisory Labor[6]	0	0	L
Maintenance[6]	14,664	1,916	M = 0.015 × TCI
Reagent Consumption[8]	14,191	3,091	N
Utilities[9]	14,586	1,509	O
Catalyst Replacement[10]	41,854	4,098	P
Total Direct Annual Costs	*85,296*	*10,613*	*DAC = L + M + N + O + P*
Indirect Annual Costs			
Overhead, Taxes, Insurance, Administration[6]	0	0	Q
Capital Recovery[11]	92,280	12,058	R
Total Indirect Annual Costs	*92,280*	*12,058*	*IDAC = Q + R*
Total Annual Cost	**177,576**	**22,672**	*TAC = DAC + IDAC*
Pollutant Removed (tpy)	7.88	1.72	
Cost per ton of NO_X Removed	**22,524**	**13,205**	*$/ton = TAC / Pollutant Removed*

1. U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual (6th Edition)* , January 2002, Section 4.2, Chapter 2.
2. Lowest $/MMBtu/hr value for boilers from Chapter 3 of MANE-VU's 2005 Assessment of Control Technology Options for BART-Eligible Sources.
3. Based on general OAQPS costs as presented on page 2-27 of Section 1, Chapter 2 of OAQPS Manual.
4. Estimates based on engineering knowledge and evaluation of costs for other equipment as specified in OAQPS Manual.
5. Based on costs as presented in Table 2.5 on page 2-44 of Section 4.2, Chapter 2 of OAQPS Manual.
6. Values for an SCR system, per OAQPS Manual, Section 4.2, Chapter 2, pages 2-44, 2-45, and 2-48.
7. Inventory capital is the cost to fill the reagent tank(s) for the first time, OAQPS Manual, Section 4.2, Chapter 2, page 2-44.
8. Reagent consumption cost calculated based on Equation 2.47 of OAQPS Manual, Section 4.2, Chapter 2, page 2-46.
9. Utilities cost calculated based on Equation 2.49 of OAQPS Manual, Section 4.2, Chapter 2, page 2-46.
10. Catalyst replacement cost presumes one layer is replaced each year and is calculated based on Equations 2.51 and 2.52 of OAQPS Manual, Section 4.2, Chapter 2, page 2-47. Assumes 24,000 hours of operation for the life of a layer and 8760 hours per year of SCR operation.
11. Capital Recovery calculated based on Equations 2.54 and 2.55 of OAQPS Manual, Section 4.2, Chapter 2, pages 2-48 and 2-49.

Table D-29. Cost Analysis Supporting Information for SNCR

Parameter	Pelletizers	Units	Note(s)	Boiler	Units	Note(s)
Maximum Boiler Capacity	75	MMBtu/hr	1	10	MMBtu/hr	1
Inlet Emissions	0.03	lb/MMBtu	1	0.05	lb/MMBtu	1
Emissions	9.86	tpy	1	2	tpy	1
Removal Efficiency	70	%	2	70	%	2
Pollutant Removed	6.9	tpy	3	1.5	tpy	3
Reagent Cost	3.26	$/gal	4	3.26	$/gal	4
Normalize Stoichiometric Ratio (Urea)	17.73	n/a	5	11.20	n/a	5
Reagent Consumption (Urea)	18.23	lb/hr	6	2.51	lb/hr	6
Reagent Solution Consumption (Urea)	3.84	gal/hr	6	0.53	gal/hr	6
Reagent Solution Storage Capacity (Urea)	1,291	gal	7	178	gal	7
Concentration of Stored Reagent Solution	50	% Reagent	8	50	% Reagent	8
Concentration of Injected Reagent Solution	10	% Reagent	8	10	% Reagent	8
Water Usage Cost	0.00097	$/gal	9	0.00097	$/gal	9
Electricity Cost	0.060	$/kW-hr	9	0.060	$/kW-hr	9
SNCR Equipment Life	20	years	10	20	years	10
Interest Rate	7.0	%	11	7.0	%	11
1998 $ (December)	163.9	n/a	12	163.9	n/a	12
1999 $	166.6	n/a	12	166.6	n/a	12
2004 $	188.9	n/a	12	188.9	n/a	12
2011 $ (May)	218.8	n/a	12	218.8	n/a	12

1. Potential inlet emissions based on maximum capacity and emissions.
2. Assumed efficiency based on EPA's Air Pollution Control Technology Fact Sheet: http://www.epa.gov/ttn/catc/dir1/fsncr.pdf
3. Pollutant Removed (tpy) = (Removal Efficiency, %) × (Emissions, tpy).
4. Cost based on example problem in OAQPS Manual, Section 4.2, Chapter 1, page 1-39, converted from December 1998 $ to 2011 $.
5. Normalized Stoichiometric Ratio for Urea calculated based on Equation 1.14 of OAQPS Manual, Section 4.2, Chapter 1, page 1-25.
6. Reagent consumption calculated based on Equations 1.15 through 1.17 in OAQPS Manual, Section 4.2, Chapter 1, pages 1-26 and 1-27.
7. Reagent storage capacity based on 14 days: Storage capacity (gal) = (Reagent Consumption, gal/hr) × (24 hr/day) × (14 days).
8. Concentration based on example problem in OAQPS Manual, Section 4.2, Chapter 1, page 1-39.
9. Cost based on site-specific utility rate.
10. Per OAQPS Manual, Section 4.2, Chapter 1, page 1-37.
11. Interest Rate based on example problem in OAQPS Manual, Section 4.2, Chapter 1, page 1-39.
12. Values based on U.S. Historical Consumer Price Index: ftp://ftp.bls.gov/pub/special.requests/cpi/cpiai.txt.

Table D-30. Cost Analysis for SNCR

Capital Cost	**Pelletizers**	**Boiler**	**OAQPS Notation[1]**
Purchased Equipment Costs			
Total Equipment and Instrumentation Cost[2]	260,614	34,054	A
Instrumentation[3]	26,061	3,405	0.10 × A
Sales Tax[3]	7,818	1,022	0.03 × A
Freight[3]	13,031	1,703	0.05 × A
Total Purchased Equipment Costs	*307,525*	*40,183*	*B = 1.18 × A*
Direct Installation Costs [4]			
Foundations and Supports	15,376	2,009	0.05 × B
Handling and Erection	61,505	8,037	0.20 × B
Electrical	12,301	1,607	0.04 × B
Piping	6,150	804	0.02 × B
Insulation	3,075	402	0.01 × B
Painting	3,075	402	0.01 × B
Total Direct Installation Costs	*101,483*	*13,260*	*C = 0.33 × B*
Indirect Installation Costs [5]			
General Facilities	20,450	2,672	0.05 × (B + C)
Engineering and Home Office Fees	40,901	5,344	0.10 × (B + C)
Process Contingencies	20,450	2,672	0.05 × (B + C)
Total Indirect Installation Costs	*81,802*	*10,689*	*D = 0.20 × (B + C)*
Project Contingency[5]	73,621	9,620	E = 0.15 × (B + C + D)
Total Plant Cost[5]	564,431	73,752	F = B + C + D + E
Allowance for Funds During Construction[6]	0	0	G
Royalty Allowance[6]	0	0	H
Preproduction Costs[5]	11,289	1,475	I = 0.02 × (F + G)
Inventory Capital[7]	4,208	579	J
Initial Catalyst and Chemicals[6]	0	0	K
Total Capital Investment	**579,927**	**75,806**	**TCI = F + G + H + I + J + K**

Operating Cost	**Pelletizers**	**Boiler**	**OAQPS Notation**
Direct Annual Costs			
Operating and Supervisory Labor[6]	0	0	L
Maintenance[6]	8,699	1,137	M = 0.015 × TCI
Reagent Consumption[8]	109,698	15,088	N
Utilities[9]	1,038	143	O
Water Consumption[10]	148	20	P
Total Direct Annual Costs	*119,582*	*16,388*	*DAC = L + M + N + O + P + Q*
Indirect Annual Costs			
Overhead, Taxes, Insurance, Administration[6]	0	0	R
Capital Recovery[11]	54,741	7,156	S
Total Indirect Annual Costs	*54,741*	*7,156*	*IDAC = R + S*
Total Annual Cost	**174,323**	**23,544**	*TAC = DAC + IDAC*
Pollutant Removed (tpy)	6.90	1.50	
Cost per ton of NO_X Removed	**25,270**	**15,672**	*$/ton = TAC / Pollutant Removed*

1. U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual (6th Edition)* , January 2002, Section 4.2, Chapter 1.

2. Estimated using average $/MMBtu/hr value for boilers from Chapter 3 of MANE-VU's 2005 Assessment of Control Technology Options for BART-Eligible Sources. Scaled from 2004 $ to 2011 $.

3. Based on general OAQPS costs as presented on page 2-27 of Section 1, Chapter 2 of OAQPS Manual.

4. Estimates based on engineering knowledge and evaluation of costs for other equipment as specified in OAQPS Manual.

5. Based on costs as presented in Table 1.4 on page 1-32 of Section 4.2, Chapter 1 of OAQPS Manual.

6. Value for an SNCR system, per OAQPS Manual, Section 4.2, Chapter 1, pages 1-32, 1-33, and 1-37.

7. Inventory capital is the cost to fill the reagent tank(s) for the first time, OAQPS Manual, Section 4.2, Chapter 1, page 1-32.

8. Reagent consumption cost calculated based on Equation 1.22 of OAQPS Manual, Section 4.2, Chapter 1, page 1-34.

9. Utilities cost calculated based on Equation 1.23 of OAQPS Manual, Section 4.2, Chapter 1, page 1-34.

10. Water consumption cost calculated based on Equation 1.25 of OAQPS Manual, Section 4.2, Chapter 1, page 1-35.

11. Capital Recovery calculated based on Equations 1.33 and 1.34 of OAQPS Manual, Section 4.2, Chapter 1, pages 1-37 and 1-38.

Table D-31. Cost Analysis Supporting Information for RTO

Parameter	Kilns	Pelletizer	Boiler	Units	Note(s)
Uncontrolled Inlet Emissions (CO)	243.1	60	3.61	tpy	1
Uncontrolled Inlet Emissions (CO)	55.5	13.73	0.82	lb/hr	1
Removal Efficiency	95	95	95	%	2
CO Removed	230.9	57	3.43	tpy	3
Control Equip. Outlet Temperature	1,450	1,450	1,450	° F	4
Current Airflow	54,777	114,018	10,882	acfm	5
Current Exhaust Temperature	258	200	380	° F	5
Current Airflow	40,282	91,214	6,840	scfm	5
Specific Heat of Air	6.85	6.85	6.85	Btu/lb-mole	6
Pressure Drop	19	19	19	inches of H_2O	7
Fan Motor Efficiency	70	70	70	%	8
Fan Electricity Usage	127.9	289.7	21.7	kW-hr	9
Energy Required From Fuel	51.31	121.84	7.82	MMBtu/hr	10
Natural Gas Heat Capacity	1,000	1,000	1,000	MMBtu/MMscf	11
Operating Labor Cost	45.0	45.0	45.0	$/hr	12
Maintenance Labor Cost	65.0	65.0	65.0	$/hr	12
Electricity Cost	0.06	0.06	0.06	$/kW-hr	12
Natural Gas Cost	8.00	8.00	8.00	$/1,000 scf	12
RTO Equipment Life	10	10	10	years	13
Interest Rate	7.0	7.0	7.0	%	13
1998 $ (2nd Quarter)	163.0	163.0	163.0	n/a	14
2002 $	179.9	179.9	179.9	n/a	14
2011 $ (May)	226.0	226.0	226.0	n/a	14

1. Potential inlet emissions based on maximum capacity and emissions.
2. Per OAQPS Manual, Section 3.2, Chapter 2.
3. Pollutant Removed (tpy) = (Removal Efficiency, %) × (Emissions, tpy).
4. Based on average operating temperature (14000, 15000) in EPA Fact Sheet: http://www.epa.gov/ttn/catc/dir1/fregen.pdf
5. Values based on stack outlet data.
6. Standard.
7. Based on example problem in OAQPS Manual, Section 3.2, Chapter 2, page 2-43.
8. Per OAQPS Manual, Section 3.2, Chapter 2, page 2-41, efficiency ranges from 40 to 70%. 70% is conservatively chosen.
9. Total Electricity usage based on Equation 2.42 of OAQPS Manual, Section 3.2, Chapter 2, page 2-41.
10. Estimated as ((Stand Pres + Stand Temp) / (Standard Pres + Exhaust Temp, °F) * Density (Air), 0.0026 lb/mole-scf * Specific Heat (Btu/lb-mol) * (Operat Temp - Exhaust Temp, °F) / 1e6 * Exhaust Gas Flowrate, acfm * 60, min/hr
11. Used in permitting.
12. Cost based on site-specific utility and labor rates.
13. Based on example problem in OAQPS Manual, Section 3.2, Chapter 2, page 2-45.
14. Values based on U.S. Historical Consumer Price Index: ftp://ftp.bls.gov/pub/special.requests/cpi/cpiai.txt.

Table D-32. Cost Analysis Supporting Information for RTO

Parameter	Kilns	Pelletizer	Boiler	Units	Note(s)
Uncontrolled Inlet Emissions (VOC)	2.36	50	0.24	tpy	1
Uncontrolled Inlet Emissions (VOC)	0.27	11	0.05	lb/hr	1
Removal Efficiency	95	95	95	%	2
VOC Removed	2.24	47	0.22	tpy	3
Control Equip. Outlet Temperature	1,450	1,450	1,450	° F	4
Current Airflow	54,777	114,018	10,882	acfm	5
Current Exhaust Temperature	258	200	4	° F	5
Current Airflow	40,282	91,214	12,383	scfm	5
Specific Heat of Air	6.85	6.85	6.85	Btu/lb-mole	6
Pressure Drop	19	19	19	inches of H_2O	7
Fan Motor Efficiency	70	70	70	%	8
Fan Electricity Usage	127.9	289.7	39.3	kW-hr	9
Energy Required From Fuel	51.31	121.84	19.13	MMBtu/hr	10
Natural Gas Heat Capacity	1,000	1,000	1,000	MMBtu/MMscf	11
Operating Labor Cost	45.0	45.0	45.0	$/hr	12
Maintenance Labor Cost	65.0	65.0	65.0	$/hr	12
Electricity Cost	0.06	0.06	0.06	$/kW-hr	12
Natural Gas Cost	8.00	8.00	8.00	$/1,000 scf	12
RTO Equipment Life	10	10	10	years	13
Interest Rate	7.0	7.0	7.0	%	13
1998 $ (2nd Quarter)	163.0	163.0	163.0	n/a	14
2002 $	179.9	179.9	179.9	n/a	14
2011 $ (May)	226.0	226.0	226.0	n/a	14

1. Potential inlet emissions based on maximum capacity and emissions.
2. Per OAQPS Manual, Section 3.2, Chapter 2.
3. Pollutant Removed (tpy) = (Removal Efficiency, %) × (Emissions, tpy).
4. Based on average operating temperature (14000, 15000) in EPA Fact Sheet: http://www.epa.gov/ttn/catc/dir1/fregen.pdf
5. Values based on stack outlet data.
6. Standard.
7. Based on example problem in OAQPS Manual, Section 3.2, Chapter 2, page 2-43.
8. Per OAQPS Manual, Section 3.2, Chapter 2, page 2-41, efficiency ranges from 40 to 70%. 70% is conservatively chosen.
9. Total Electricity usage based on Equation 2.42 of OAQPS Manual, Section 3.2, Chapter 2, page 2-41.
10. Estimated as ((Stand Pres + Stand Temp) / (Standard Pres + Exhaust Temp, °F) * Density (Air), 0.0026 lb/mole-scf * Specific Heat (Btu/lb-mol) * (Operat Temp - Exhaust Temp, °F) / 1e6 * Exhaust Gas Flowrate, acfm * 60, min/hr
11. Used in permitting.
12. Cost based on site-specific utility and labor rates.
13. Based on example problem in OAQPS Manual, Section 3.2, Chapter 2, page 2-45.
14. Values based on U.S. Historical Consumer Price Index: ftp://ftp.bls.gov/pub/special.requests/cpi/cpiai.txt.

Table D-33. Cost Analysis for RTO for CO control

Capital Cost	Kilns	Pelletizer	Boiler	OAQPS Notation[1]
Purchased Equipment Costs				
Total Equipment Cost[2]	4,427,146	10,024,888	751,760	A
Instrumentation	442,715	1,002,489	75,176	0.10 × A
Sales Tax	132,814	300,747	22,553	0.03 × A
Freight	221,357	501,244	37,588	0.05 × A
Total Purchased Equipment Costs	*5,224,033*	*11,829,368*	*887,077*	*B = 1.18 × A*
Direct Installation Costs				
Foundations and Supports	417,923	946,349	70,966	0.08 × B
Handling and Erection	731,365	1,656,112	124,191	0.14 × B
Electrical	208,961	473,175	35,483	0.04 × B
Piping	104,481	236,587	17,742	0.02 × B
Insulation	52,240	118,294	8,871	0.01 × B
Painting	52,240	118,294	8,871	0.01 × B
Site Preparation & Buildings	-	-	-	-
Additional duct work	-	-	-	-
Total Direct Installation Costs	*1,567,210*	*3,548,811*	*266,123*	*C = 0.30 × B*
Indirect Installation Costs				
Engineering	522,403	1,182,937	88,708	0.10 × B
Construction and Field Expense	261,202	591,468	44,354	0.05 × B
Contractor Fees	522,403	1,182,937	88,708	0.10 × B
Start-up	104,481	236,587	17,742	0.02 × B
Performance Test	52,240	118,294	8,871	0.01 × B
Process Contingencies	156,721	354,881	26,612	0.03 × B
Total Indirect Installation Costs	*1,619,450*	*3,667,104*	*274,994*	*D = 0.36 × B*
Total Capital Investment	**8,410,692**	**19,045,283**	**1,428,195**	**TCI = B + C + D**

Operating Cost	Kilns	Pelletizer	Boiler	OAQPS Notation
Direct Annual Costs				
Operating Labor (0.5 hr, per 8-hr shift)	24,638	24,638	24,638	E
Supervisory Labor	3,696	3,696	3,696	F = 0.15 × E
Maintenance Labor (0.5 hr, per 8-hr shift)	35,588	35,588	35,588	G
Maintenance Materials	35,588	35,588	35,588	H = G
Electricity	67,236	152,251	11,417	I
Natural Gas	3,595,781	8,538,522	548,096	K
Total Direct Annual Costs	*3,762,526*	*8,790,281*	*659,021*	*DAC = E + F + G + H + I + J + K*
Indirect Annual Costs				
Overhead	59,705	59,705	59,705	L = 0.60 × (E + F + G + H)
Administrative Charges	168,214	380,906	28,564	M = 0.02 × TCI
Property Tax	84,107	190,453	14,282	N = 0.01 × TCI
Insurance	84,107	190,453	14,282	O = 0.01 × TCI
Capital Recovery[3]	1,197,493	2,711,620	203,343	P
Total Indirect Annual Costs	*1,593,626*	*3,533,136*	*320,175*	*IDAC = L + M + N + O + P*
Total Annual Cost	**4,960,019**	**11,501,901**	**862,364**	*TAC = DAC + IDAC*
Pollutant Removed (tpy)	230.93	57.11	3.43	
Cost per ton of Pollutant Removed	**21,479**	**201,400**	**251,760**	*$/ton = TAC / Pollutant Removed*

1. U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual (6th Edition)*, January 2002, Section 3.2, Chapter 2.
2. Capital Costs are based the EPA CATC Catalytic Incinerator Fact Sheet (EPA-452/F-03-018) average $/scfm capital cost, scaled from 2002 $ to 2011 $.
3. Capital Recovery calculated based on Equations 2.54 and 2.55 of OAQPS Manual, Section 4.2, Chapter 2, pages 2-48 and 2-49.

Table D-34. Cost Analysis for RTO for VOC control

Capital Cost	Kilns	Pelletizer	Boiler	OAQPS Notation[1]
Purchased Equipment Costs				
Total Equipment Cost[2]	4,427,146	10,024,888	1,360,946	A
Instrumentation	442,715	1,002,489	136,095	0.10 × A
Sales Tax	132,814	300,747	40,828	0.03 × A
Freight	221,357	501,244	68,047	0.05 × A
Total Purchased Equipment Costs	*5,224,033*	*11,829,368*	*1,605,916*	*B = 1.18 × A*
Direct Installation Costs				
Foundations and Supports	417,923	946,349	128,473	0.08 × B
Handling and Erection	731,365	1,656,112	224,828	0.14 × B
Electrical	208,961	473,175	64,237	0.04 × B
Piping	104,481	236,587	32,118	0.02 × B
Insulation	52,240	118,294	16,059	0.01 × B
Painting	52,240	118,294	16,059	0.01 × B
Site Preparation & Buildings	-	-	-	-
Additional duct work	-	-	-	-
Total Direct Installation Costs	*1,567,210*	*3,548,811*	*481,775*	*C = 0.30 × B*
Indirect Installation Costs				
Engineering	522,403	1,182,937	160,592	0.10 × B
Construction and Field Expense	261,202	591,468	80,296	0.05 × B
Contractor Fees	522,403	1,182,937	160,592	0.10 × B
Start-up	104,481	236,587	32,118	0.02 × B
Performance Test	52,240	118,294	16,059	0.01 × B
Process Contingencies	156,721	354,881	48,177	0.03 × B
Total Indirect Installation Costs	*1,619,450*	*3,667,104*	*497,834*	*D = 0.36 × B*
Total Capital Investment	**8,410,692**	**19,045,283**	**2,585,525**	**TCI = B + C + D**

Operating Cost	Kilns	Pelletizer	Boiler	OAQPS Notation
Direct Annual Costs				
Operating Labor (0.5 hr, per 8-hr shift)	24,638	24,638	24,638	E
Supervisory Labor	3,696	3,696	3,696	F = 0.15 × E
Maintenance Labor (0.5 hr, per 8-hr shift)	35,588	35,588	35,588	G
Maintenance Materials	35,588	35,588	35,588	H = G
Electricity	67,236	152,251	20,669	I
Natural Gas	3,595,781	8,538,522	1,340,918	K
Total Direct Annual Costs	*3,762,526*	*8,790,281*	*1,461,095*	*DAC = E + F + G + H + I + J + K*
Indirect Annual Costs				
Overhead	59,705	59,705	59,705	L = 0.60 × (E + F + G + H)
Administrative Charges	168,214	380,906	51,710	M = 0.02 × TCI
Property Tax	84,107	190,453	25,855	N = 0.01 × TCI
Insurance	84,107	190,453	25,855	O = 0.01 × TCI
Capital Recovery[3]	1,197,493	2,711,620	368,121	P
Total Indirect Annual Costs	*1,593,626*	*3,533,136*	*531,246*	*IDAC = L + M + N + O + P*
Total Annual Cost	**4,960,019**	**11,501,901**	**1,829,216**	*TAC = DAC + IDAC*
Pollutant Removed (tpy)	2.24	47.31	0.22	
Cost per ton of Pollutant Removed	**2,212,319**	**243,115**	**8,156,023**	*$/ton = TAC / Pollutant Removed*

1. U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual (6th Edition)*, January 2002, Section 3.2, Chapter 2.
2. Capital Costs are based the EPA CATC Catalytic Incinerator Fact Sheet (EPA-452/F-03-018) average $/scfm capital cost, scaled from 2002 $ to 2011 $.
3. Capital Recovery calculated based on Equations 2.54 and 2.55 of OAQPS Manual, Section 4.2, Chapter 2, pages 2-48 and 2-49.

Table D-35. Cost Analysis Supporting Information for Tail-End Oxidation Catalyst

Parameter	Kilns	Pelletizer	Boiler	Units	Note(s)
Uncontrolled Inlet Emissions (CO)	243.1	60	3.6056	tpy	1
Uncontrolled Inlet Emissions (CO)	55.5	13.73	0.82	lb/hr	1
Uncontrolled Inlet Emissions (CO)	1.04	0.183	0.084	lb/MMBtu	1
Removal Efficiency	95	95	95	%	2
CO Removed	230.9	57	3.43	tpy	3
Inlet Temperature Needed	700	700	700	° F	4
Current Airflow	54,777	114,018	10,882	acfm	5
Current Temperature	258	200	380	° F	5
Current Airflow	40,282	91,214	6,840	scfm	5
Inlet Airflow to Oxidation Catalyst	88,498	200,395	15,028	acfm	6
Ammonia Slip Allowed	2	2	2	ppm	8
Specific Heat (Air)	6.85	6.85	6.85	Btu/lb-mole	7
Volume of Catalyst	78	177	13	ft^3	8
Pressure Drop Across the Oxidation Catalyst	23.0	23.0	23.0	inches of H_2O	9
Fan Motor Efficiency	70	70	70	%	10
Electricity Usage	340.2	770.4	57.8	kW-hr	11
Catalyst Life	2	2	2	year	12
Fuel Reheating Need	30.74	85.66	3.23	MMBtu/hr	13
Natural Gas Heat Capacity	1,000	1,000	1,000	MMBtu/MMscf	14
Catalyst Cost, Initial	901.08	901.08	901.08	$\$/ft^3$	12
Catalyst Cost, Replacement	901.08	901.08	901.08	$\$/ft^3$	12
Operating Labor Cost	45.00	45.00	45.00	$/hr	15
Maintenance Labor Cost	65.00	65.00	65.00	$/hr	15
Electricity Cost	0.06	0.060	0.06	$/kW-hr	15
Natural Gas Cost	8.00	8.00	8.00	$/1,000 scf	15
Oxidation Catalyst Equipment Life	10	10	10	years	12
Interest Rate	7.0	7.0	7.0	%	12
1998 $ (2nd Quarter)	163.0	163.0	163.0	n/a	16
2002 $	179.9	179.9	179.9	n/a	16
2011 $ (May)	226.0	226.0	226.0	n/a	16

1. Potential inlet emissions based on maximum capacity and emissions.
2. Per OAQPS Manual, Section 3.2, Chapter 2.
3. Pollutant Removed (tpy) = (Removal Efficiency, %) × (Emissions, tpy).
4. Estimated average (600F - 800F) needed per EPA Spec Sheet http://www.epa.gov/ttn/catc/dir1/fcataly.pdf
5. Values based on stack outlet data.
6. Calculated based on needed catalyst temperature.
7. Standard.
8. Ammonia Slip based on example problem in OAQPS Manual, Section 4.2, Chapter 2, page 2-50.
Volume of catalyst calculated using reference from OAQPS Total Annual Cost Spreadsheet Program for Catalytic Unit
9. Based on example problem in OAQPS Manual, Section 3.2, Chapter 2, page 2-43.
10. Per OAQPS Manual, Section 3.2, Chapter 2, page 2-41, efficiency ranges from 40 to 70%. 70% is conservatively chosen.
11. Total Electricity usage based on Equation 2.42 of OAQPS Manual, Section 3.2, Chapter 2, page 2-41.
12. Based on example problem in OAQPS Manual, Section 3.2, Chapter 2, page 2-45. Converted from 1998 $ to 2011 $.
13. Estimated as ((Stand Pres + Stand Temp) / (Standard Pres + Exhaust Temp, °F) * Density (Air), 0.0026 lb/mole-scf * Specific Heat (Btu/lb-mol) * (Operat Temp - Exhaust Temp, °F) / 1e6 * Exhaust Gas Flowrate, acfm * 60, min/hr
14. Used in permitting.
15. Cost based on site-specific utility and labor rates.
16. Values based on U.S. Historical Consumer Price Index: ftp://ftp.bls.gov/pub/special.requests/cpi/cpiai.txt.

Table D-36. Cost Analysis Supporting Information for Tail-End Oxidation Catalyst

Parameter	Kilns	Pelletizer	Boiler	Units	Note(s)
Uncontrolled Inlet Emissions (VOC)	2.36	50	0.24	tpy	1
Uncontrolled Inlet Emissions (VOC)	0.27	11	0.05	lb/hr	1
Uncontrolled Inlet Emissions (VOC)	0.0055	0.152	0.006	lb/MMBtu	1
Removal Efficiency	95	95	95	%	2
VOC Removed	2.24	47	0.22	tpy	3
Inlet Temperature Needed	700	700	700	° F	4
Current Airflow	54,777	114,018	10,882	acfm	5
Current Temperature	258	200	380	° F	5
Current Airflow	40,282	91,214	6,840	scfm	5
Inlet Airflow to Oxidation Catalyst	88,498	200,395	15,028	acfm	6
Ammonia Slip Allowed	2	2	2	ppm	8
Specific Heat (Air)	6.85	6.85	6.85	Btu/lb-mole	7
Volume of Catalyst	78	177	13	ft^3	8
Pressure Drop Across the Oxidation Catalyst	23.0	23.0	23.0	inches of H_2O	9
Fan Motor Efficiency	70	70	70	%	10
Electricity Usage	340.2	770.4	57.8	kW-hr	11
Catalyst Life	2	2	2	year	12
Fuel Reheating Need	30.74	85.66	3.23	MMBtu/hr	13
Natural Gas Heat Capacity	1,000	1,000	1,000	MMBtu/MMscf	14
Catalyst Cost, Initial	901.08	901.08	901.08	$\$/ft^3$	12
Catalyst Cost, Replacement	901.08	901.08	901.08	$\$/ft^3$	12
Operating Labor Cost	45.00	45.00	45.00	$/hr	15
Maintenance Labor Cost	65.00	65.00	65.00	$/hr	15
Electricity Cost	0.06	0.060	0.06	$/kW-hr	15
Natural Gas Cost	8.00	8.00	8.00	$/1,000 scf	15
Oxidation Catalyst Equipment Life	10	10	10	years	12
Interest Rate	7.0	7.0	7.0	%	12
1998 $ (2nd Quarter)	163.0	163.0	163.0	n/a	16
2002 $	179.9	179.9	179.9	n/a	16
2011 $ (May)	226.0	226.0	226.0	n/a	16

1. Potential inlet emissions based on maximum capacity and emissions.
2. Per OAQPS Manual, Section 3.2, Chapter 2.
3. Pollutant Removed (tpy) = (Removal Efficiency, %) × (Emissions, tpy).
4. Estimated average (600F - 800F) needed per EPA Spec Sheet http://www.epa.gov/ttn/catc/dir1/fcataly.pdf
5. Values based on stack outlet data.
6. Calculated based on needed catalyst temperature.
7. Standard.
8. Ammonia Slip based on example problem in OAQPS Manual, Section 4.2, Chapter 2, page 2-50.
Volume of catalyst calculated using reference from OAQPS Total Annual Cost Spreadsheet Program for Catalytic Unit
9. Based on example problem in OAQPS Manual, Section 3.2, Chapter 2, page 2-43.
10. Per OAQPS Manual, Section 3.2, Chapter 2, page 2-41, efficiency ranges from 40 to 70%. 70% is conservatively chosen.
11. Total Electricity usage based on Equation 2.42 of OAQPS Manual, Section 3.2, Chapter 2, page 2-41.
12. Based on example problem in OAQPS Manual, Section 3.2, Chapter 2, page 2-45. Converted from 1998 $ to 2011 $.
13. Estimated as ((Stand Pres + Stand Temp) / (Standard Pres + Exhaust Temp, °F) * Density (Air), 0.0026 lb/mole-scf * Specific Heat (Btu/lb-mol) * (Operat Temp - Exhaust Temp, °F) / 1e6 * Exhaust Gas Flowrate, acfm * 60, min/hr
14. Used in permitting.
15. Cost based on site-specific utility and labor rates.
16. Values based on U.S. Historical Consumer Price Index: ftp://ftp.bls.gov/pub/special.requests/cpi/cpiai.txt.

Table D-37. Cost Analysis for Tail-End Oxidation Catalyst (Stand-Alone) for CO control

Capital Cost	**Kilns**	**Pelletizer**	**Boiler**	**OAQPS Notation[1]**
Purchased Equipment Costs				
Total Equipment Cost[2]	2,833,374	6,415,929	481,127	A
Instrumentation	283,337	641,593	48,113	0.10 × A
Sales Tax	85,001	192,478	14,434	0.03 × A
Freight	141,669	320,796	24,056	0.05 × A
Total Purchased Equipment Costs	*3,343,381*	*7,570,796*	*567,730*	*B = 1.18 × A*
Direct Installation Costs				
Foundations and Supports	267,470	605,664	45,418	0.08 × B
Handling and Erection	468,073	1,059,911	79,482	0.14 × B
Electrical	133,735	302,832	22,709	0.04 × B
Piping	66,868	151,416	11,355	0.02 × B
Insulation	33,434	75,708	5,677	0.01 × B
Painting	33,434	75,708	5,677	0.01 × B
Total Direct Installation Costs	*1,003,014*	*2,271,239*	*170,319*	*C = 0.30 × B*
Indirect Installation Costs				
Engineering	334,338	757,080	56,773	0.10 × B
Construction and Field Expense	167,169	378,540	28,386	0.05 × B
Contractor Fees	334,338	757,080	56,773	0.10 × B
Start-up	66,868	151,416	11,355	0.02 × B
Performance Test	33,434	75,708	5,677	0.01 × B
Process Contingencies	100,301	227,124	17,032	0.03 × B
Total Indirect Installation Costs	*1,036,448*	*2,346,947*	*175,996*	*D = 0.36 × B*
Total Capital Investment	**5,382,843**	**12,188,981**	**914,045**	**TCI = B + C + D**

Operating Cost	**Kilns**	**Pelletizer**	**Boiler**	**OAQPS Notation**
Direct Annual Costs				
Operating Labor (0.5 hr, per 8-hr shift)	24,638	24,638	24,638	E
Supervisory Labor	3,696	3,696	3,696	F = 0.15 × E
Maintenance Labor (0.5 hr, per 8-hr shift)	35,588	35,588	35,588	G
Maintenance Materials	35,588	35,588	35,588	H = G
Electricity	178,815	404,910	30,364	I
Catalyst Replacement[3]	33,960	76,898	5,767	J
Natural Gas for Gas Reheating	2,154,134	6,002,839	226,361	K
Total Direct Annual Costs	*2,466,417*	*6,584,156*	*361,999*	*DAC = E + F + G + H + I + J + K*
Indirect Annual Costs				
Overhead	59,705	59,705	59,705	L = 0.60 × (E + F + G + H)
Administrative Charges	107,657	243,780	18,281	M = 0.02 × TCI
Property Tax	53,828	121,890	9,140	N = 0.01 × TCI
Insurance	53,828	121,890	9,140	O = 0.01 × TCI
Capital Recovery[4]	766,396	1,735,437	130,139	P
Total Indirect Annual Costs	*1,041,414*	*2,282,701*	*226,406*	*IDAC = L + M + N + O + P*
Total Annual Cost	**3,232,812**	**8,319,593**	**492,139**	*TAC = DAC + IDAC*
Pollutant Removed (tpy)	230.93	57.11	3.43	
Cost per ton of Pollutant Removed	**13,999**	**145,677**	**143,676**	*$/ton = TAC / Pollutant Removed*

1. U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual (6th Edition)* , January 2002, Section 3.2, Chapter 2.
2. Capital Costs are based the EPA CATC Catalytic Incinerator Fact Sheet (EPA-452/F-03-018) average $/scfm capital cost, scaled from 2002 $ to 2011 $.
3. Catalyst replacement is calculated based Future Worth Factor from Equations 2.51 and 2.52 of OAQPS Manual, Section 4.2, Chapter 2, page 2-47.
4. Capital Recovery calculated based on Equations 2.54 and 2.55 of OAQPS Manual, Section 4.2, Chapter 2, pages 2-48 and 2-49.

Table D-38. Cost Analysis for Tail-End Oxidation Catalyst (Stand-Alone) for VOC control

Capital Cost	**Kilns**	**Pelletizer**	**Boiler**	**OAQPS Notation[1]**
Purchased Equipment Costs				
Total Equipment Cost[2]	2,833,374	6,415,929	481,127	A
Instrumentation	283,337	641,593	48,113	0.10 × A
Sales Tax	85,001	192,478	14,434	0.03 × A
Freight	141,669	320,796	24,056	0.05 × A
Total Purchased Equipment Costs	*3,343,381*	*7,570,796*	*567,730*	*B = 1.18 × A*
Direct Installation Costs				
Foundations and Supports	267,470	605,664	45,418	0.08 × B
Handling and Erection	468,073	1,059,911	79,482	0.14 × B
Electrical	133,735	302,832	22,709	0.04 × B
Piping	66,868	151,416	11,355	0.02 × B
Insulation	33,434	75,708	5,677	0.01 × B
Painting	33,434	75,708	5,677	0.01 × B
Total Direct Installation Costs	*1,003,014*	*2,271,239*	*170,319*	*C = 0.30 × B*
Indirect Installation Costs				
Engineering	334,338	757,080	56,773	0.10 × B
Construction and Field Expense	167,169	378,540	28,386	0.05 × B
Contractor Fees	334,338	757,080	56,773	0.10 × B
Start-up	66,868	151,416	11,355	0.02 × B
Performance Test	33,434	75,708	5,677	0.01 × B
Process Contingencies	100,301	227,124	17,032	0.03 × B
Total Indirect Installation Costs	*1,036,448*	*2,346,947*	*175,996*	*D = 0.36 × B*
Total Capital Investment	**5,382,843**	**12,188,981**	**914,045**	**TCI = B + C + D**

Operating Cost	**Kilns**	**Pelletizer**	**Boiler**	**OAQPS Notation**
Direct Annual Costs				
Operating Labor (0.5 hr, per 8-hr shift)	24,638	24,638	24,638	E
Supervisory Labor	3,696	3,696	3,696	F = 0.15 × E
Maintenance Labor (0.5 hr, per 8-hr shift)	35,588	35,588	35,588	G
Maintenance Materials	35,588	35,588	35,588	H = G
Electricity	178,815	404,910	30,364	I
Catalyst Replacement[3]	33,960	76,898	5,767	J
Natural Gas for Gas Reheating	2,154,134	6,002,839	226,361	K
Total Direct Annual Costs	*2,466,417*	*6,584,156*	*361,999*	*DAC = E + F + G + H + I + J + K*
Indirect Annual Costs				
Overhead	59,705	59,705	59,705	L = 0.60 × (E + F + G + H)
Administrative Charges	107,657	243,780	18,281	M = 0.02 × TCI
Property Tax	53,828	121,890	9,140	N = 0.01 × TCI
Insurance	53,828	121,890	9,140	O = 0.01 × TCI
Capital Recovery[4]	766,396	1,735,437	130,139	P
Total Indirect Annual Costs	*1,041,414*	*2,282,701*	*226,406*	*IDAC = L + M + N + O + P*
Total Annual Cost	**3,232,812**	**8,319,593**	**492,139**	*TAC = DAC + IDAC*
Pollutant Removed (tpy)	2.24	47.31	0.22	
Cost per ton of Pollutant Removed	**1,441,932**	**175,851**	**2,194,326**	*$/ton = TAC / Pollutant Removed*

1. U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual (6th Edition)* , January 2002, Section 3.2, Chapter 2.
2. Capital Costs are based the EPA CATC Catalytic Incinerator Fact Sheet (EPA-452/F-03-018) average $/scfm capital cost, scaled from 2002 $ to 2011 $.
3. Catalyst replacement is calculated based Future Worth Factor from Equations 2.51 and 2.52 of OAQPS Manual, Section 4.2, Chapter 2, page 2-47.
4. Capital Recovery calculated based on Equations 2.54 and 2.55 of OAQPS Manual, Section 4.2, Chapter 2, pages 2-48 and 2-49.

APPENDIX E – CASE-BY-CASE MACT SUPPORTING INFORMATION

in such State or local jurisdiction unless:

(1) The major source in question has been specifically regulated or exempted from regulation under a standard issued pursuant to section 112(d), section 112(h) or section 112(j) in part 63, and the owner and operator has fully complied with all procedures and requirements for preconstruction review established by that standard, including any applicable requirements set forth in subpart A of this part 63; or

(2) The permitting authority has made a final and effective case-by-case determination pursuant to the provisions of § 63.43 such that emissions from the constructed or reconstructed major source will be controlled to a level no less stringent than the maximum achievable control technology emission limitation for new sources.

[61 FR 68400, Dec. 27, 1996, as amended at 64 FR 35032, June 30, 1999]

§ 63.43 Maximum achievable control technology (MACT) determinations for constructed and reconstructed major sources.

(a) *Applicability*. The requirements of this section apply to an owner or operator who constructs or reconstructs a major source of HAP subject to a case-by-case determination of maximum achievable control technology pursuant to § 63.42(c).

(b) *Requirements for constructed and reconstructed major sources*. When a case-by-case determination of MACT is required by § 63.42(c), the owner and operator shall obtain from the permitting authority an approved MACT determination according to one of the review options contained in paragraph (c) of this section.

(c) *Review options*. (1) When the permitting authority requires the owner or operator to obtain, or revise, a permit issued pursuant to title V of the Act before construction or reconstruction of the major source, or when the permitting authority allows the owner or operator at its discretion to obtain or revise such a permit before construction or reconstruction, and the owner or operator elects that option, the owner or operator shall follow the administrative procedures in the program approved under title V of the Act (or in other regulations issued pursuant to title V of the Act, where applicable).

(2) When an owner or operator is not required to obtain or revise a title V permit (or other permit issued pursuant to title V of the Act) before construction or reconstruction, the owner or operator (unless the owner or operator voluntarily follows the process to obtain a title V permit) shall either, at the discretion of the permitting authority:

(i) Apply for and obtain a Notice of MACT Approval according to the procedures outlined in paragraphs (f) through (h) of this section; or

(ii) Apply for a MACT determination under any other administrative procedures for preconstruction review and approval established by the permitting authority for a State or local jurisdiction which provide for public participation in the determination, and ensure that no person may begin actual construction or reconstruction of a major source in that State or local jurisdiction unless the permitting authority determines that the MACT emission limitation for new sources will be met.

(3) When applying for a permit pursuant to title V of the Act, an owner or operator may request approval of case-by-case MACT determinations for alternative operating scenarios. Approval of such determinations satisfies the requirements of section 112(g) of each such scenario.

(4) Regardless of the review process, the MACT emission limitation and requirements established shall be effective as required by paragraph (j) of this section, consistent with the principles established in paragraph (d) of this section, and supported by the information listed in paragraph (e) of this section. The owner or operator shall comply with the requirements in paragraphs (k) and (l) of this section, and with all applicable requirements in subpart A of this part.

(d) *Principles of MACT determinations*. The following general principles shall govern preparation by the owner or operator of each permit application or other application requiring a case-by-case MACT determination concerning construction or reconstruction of a major source, and all subsequent review of and actions taken concerning such an application by the permitting authority:

(1) The MACT emission limitation or MACT requirements recommended by the applicant and approved by the permitting authority shall not be less stringent than the emission control which is achieved in practice by the best controlled similar source, as determined by the permitting authority.

(2) Based upon available information, as defined in this subpart, the MACT emission limitation and control technology (including any requirements under paragraph (d)(3) of this section) recommended by the applicant and approved by the permitting authority shall achieve the maximum degree of reduction in emissions of HAP which can be achieved by utilizing those control technologies that can be identified from the available information, taking into consideration the costs of achieving such emission reduction and any non-air quality health and environmental impacts and energy requirements associated with the emission reduction.

(3) The applicant may recommend a specific design, equipment, work practice, or operational standard, or a combination thereof, and the permitting authority may approve such a standard if the permitting authority specifically determines that it is not feasible to prescribe or enforce an emission limitation under the criteria set forth in section 112(h)(2) of the Act.

(4) If the Administrator has either proposed a relevant emission standard pursuant to section 112(d) or section 112(h) of the Act or adopted a presumptive MACT determination for the source category which includes the constructed or reconstructed major source, then the MACT requirements applied to the constructed or reconstructed major source shall have considered those MACT emission limitations and requirements of the proposed standard or presumptive MACT determination.

(e) *Application requirements for a case-by-case MACT determination.* (1) An application for a MACT determination (whether a permit application under title V of the Act, an application for a Notice of MACT Approval, or other document specified by the permitting authority under paragraph (c)(2)(ii) of this section) shall specify a control technology selected by the owner or operator that, if properly operated and maintained, will meet the MACT emission limitation or standard as determined according to the principles set forth in paragraph (d) of this section.

(2) In each instance where a constructed or reconstructed major source would require additional control technology or a change in control technology, the application for a MACT determination shall contain the following information:

(i) The name and address (physical location) of the major source to be constructed or reconstructed;

(ii) A brief description of the major source to be constructed or reconstructed and identification of any listed source category or categories in which it is included;

(iii) The expected commencement date for the construction or reconstruction of the major source;

(iv) The expected completion date for construction or reconstruction of the major source;

(v) the anticipated date of start-up for the constructed or reconstructed major source;

(vi) The HAP emitted by the constructed or reconstructed major source, and the estimated emission rate for each such HAP, to the extent this information is needed by the permitting authority to determine MACT;

(vii) Any federally enforceable emission limitations applicable to the constructed or reconstructed major source;

(viii) The maximum and expected utilization of capacity of the constructed or reconstructed major source, and the associated uncontrolled emission rates for that source, to the extent this information is needed by the permitting authority to determine MACT;

(ix) The controlled emissions for the constructed or reconstructed major source in tons/yr at expected and maximum utilization of capacity, to the extent this information is needed by the permitting authority to determine MACT;

(x) A recommended emission limitation for the constructed or reconstructed major source consistent with the principles set forth in paragraph (d) of this section;

(xi) The selected control technology to meet the recommended MACT emission limitation, including technical information on the design, operation, size, estimated control efficiency of the control technology (and the manufacturer's name, address, telephone number, and relevant specifications and drawings, if requested by the permitting authority);

(xii) Supporting documentation including identification of alternative control technologies considered by the applicant to meet the emission limitation, and analysis of cost and non-air quality health environmental impacts or energy requirements for the selected control technology; and

(xiii) Any other relevant information required pursuant to subpart A.

(3) In each instance where the owner or operator contends that a constructed or reconstructed major source will be in compliance, upon startup, with case-by-case MACT under this subpart without a change in control technology, the application for a MACT determination shall contain the following information:

(i) The information described in paragraphs (e)(2)(i) through (e)(2)(x) of this section; and

(ii) Documentation of the control technology in place.

(f) *Administrative procedures for review of the Notice of MACT Approval.* (1) The permitting authority will notify the owner or operator in writing, within 45 days from the date the application is first received, as to whether the application for a MACT determination is complete or whether additional information is required.

(2) The permitting authority will initially approve the recommended MACT emission limitation and other terms set forth in the application, or the permitting authority will notify the owner or operator in writing of its intent to disapprove the application, within 30 calendar days after the owner or operator is notified in writing that the application is complete.

(3) The owner or operator may present, in writing, within 60 calendar days after receipt of notice of the permitting authority's intent to disapprove the application, additional information or arguments pertaining to, or amendments to, the application for consideration by the permitting authority before it decides whether to finally disapprove the application.

(4) The permitting authority will either initially approve or issue a final disapproval of the application within 90 days after it notifies the owner or operator of an intent to disapprove or within 30 days after the date additional information is received from the owner or operator; whichever is earlier.

(5) A final determination by the permitting authority to disapprove any application will be in writing and will specify the grounds on which the disapproval is based. If any application is finally disapproved, the owner or operator may submit a subsequent application concerning construction or reconstruction of the same major source, provided that the subsequent application has been amended in response to the stated grounds for the prior disapproval.

(6) An initial decision to approve an application for a MACT determination will be set forth in the Notice of MACT Approval as described in paragraph (g) of this section.

(g) *Notice of MACT Approval.* (1) The Notice of MACT Approval will contain a MACT emission limitation (or a MACT work practice standard if the permitting authority determines it is not feasible to prescribe or enforce an emission standard) to control the emissions of HAP. The MACT emission limitation or standard will be determined by the permitting authority and will conform to the principles set forth in paragraph (d) of this section.

(2) The Notice of MACT Approval will specify any notification, operation and maintenance, performance testing, monitoring, reporting and record keeping requirements. The Notice of MACT Approval shall include:

(i) In addition to the MACT emission limitation or MACT work practice standard established under this subpart, additional emission limits, production limits, operational limits or other terms and conditions necessary to ensure Federal enforceability of the MACT emission limitation;

(ii) Compliance certifications, testing, monitoring, reporting and record keeping requirements that are consistent with the requirements of § 70.6(c) of this chapter;

(iii) In accordance with section 114(a)(3) of the Act, monitoring shall be capable of demonstrating continuous compliance during the applicable reporting period. Such monitoring data shall be of sufficient quality to be used as a basis for enforcing all applicable requirements established under this subpart, including emission limitations;

(iv) A statement requiring the owner or operator to comply with all applicable requirements contained in subpart A of this part;

(3) All provisions contained in the Notice of MACT Approval shall be federally enforceable upon the effective date of issuance of such notice, as provided by paragraph (j) of this section.

(4) The Notice of MACT Approval shall expire if construction or reconstruction has not commenced within 18 months of issuance, unless the permitting authority has granted an extension which shall not exceed an additional 12 months.

(h) *Opportunity for public comment on the Notice of MACT Approval.* (1) The permitting authority will provide opportunity for public comment on the Notice of MACT Approval, including, at a minimum:

(i) Availability for public inspection in at least one location in the area affected of the information submitted by the owner or operator and of the permitting authority's initial decision to approve the application;

(ii) A 30-day period for submittal of public comment; and

(iii) A notice by prominent advertisement in the area affected of the location of the source information and initial decision specified in paragraph (h)(1)(i) of this section.

(2) At the discretion of the permitting authority, the Notice of MACT Approval setting forth the initial decision to approve the application may become final automatically at the end of the comment period if no adverse comments are received. If adverse comments are received, the permitting authority shall have 30 days after the end of the comment period to make any necessary revisions in its analysis and decide whether to finally approve the application.

(i) *EPA notification.* The permitting authority shall send a copy of the final Notice of MACT Approval, notice of approval of a title V permit application incorporating a MACT determination (in those instances where the owner or operator either is required or elects to obtain such a permit before construction or reconstruction), or other notice of approval issued pursuant to paragraph (c)(2)(ii) of this section to the Administrator through the appropriate Regional Office, and to all other State and local air pollution control agencies having jurisdiction in affected States.

(j) *Effective date.* The effective date of a MACT determination shall be the date the Notice of MACT Approval becomes final, the date of issuance of a title V permit incorporating a MACT determination (in those instances where the owner or operator either is required or elects to obtain such a permit before construction or reconstruction), or the date any other notice of approval issued pursuant to paragraph (c)(2)(ii) of this section becomes final.

(k) *Compliance date.* On and after the date of start-up, a constructed or reconstructed major source which is subject to the requirements of this subpart shall be in compliance with all applicable requirements specified in the MACT determination.

(l) *Compliance with MACT determinations.* (1) An owner or operator of a constructed or reconstructed major source that is subject to a MACT determination shall comply with all requirements in the final Notice of MACT Approval, the title V permit (in those instances where the owner or operator either is required or elects to obtain such a permit before construction or reconstruction), or any other final notice of approval issued pursuant to paragraph (c)(2)(ii) of this section, including but not limited to any MACT emission limitation or MACT work practice standard, and any notification, operation and maintenance, performance testing, monitoring, reporting, and recordkeeping requirements.

(2) An owner or operator of a constructed or reconstructed major source which has obtained a MACT determination shall be deemed to be in compliance with section 112(g)(2)(B) of the Act only to the extent that the constructed or reconstructed major source is in compliance with all requirements set forth in the final Notice of MACT Approval, the title V permit (in those instances where the owner or operator either is required or elects to obtain such a permit before construction or reconstruction), or any other final notice of approval issued pursuant to paragraph (c)(2)(ii) of this section. Any violation of such requirements by the owner or operator shall be deemed by the permitting authority and by EPA to be a violation of the prohibition on construction or reconstruction in section 112(g)(2)(B) for whatever period the owner or operator is determined to be in violation of such requirements, and shall subject the owner or operator to appropriate enforcement action under the Act.

(m) *Reporting to the Administrator.* Within 60 days of the issuance of a final Notice of MACT Approval, a title V permit incorporating a MACT determination (in those instances where the owner or operator either is required or elects to obtain such a permit before construction or reconstruction), or any other final notice of approval issued pursuant to paragraph (c)(2)(ii) of this section, the permitting authority shall provide a copy of such notice to the Administrator, and shall provide a summary in a compatible electronic format for inclusion in the MACT data base.

[20 FR 68401, Dec. 27, 1996]

§ 63.44 Requirements for constructed or reconstructed major sources subject to a subsequently promulgated MACT standard or MACT requirement.

(a) If the Administrator promulgates an emission standard under section 112(d) or section 112(h) of the Act or the permitting authority issues a determination under section 112(j) of the Act that is applicable to a stationary source or group of sources which would be deemed to be a constructed or reconstructed major source under this subpart before the date that the owner or operator has obtained a final and legally effective MACT determination under any of the review options available pursuant to § 63.43, the owner or operator of the source(s) shall comply with the promulgated standard or determination rather than any MACT determination under section 112(g) by the permitting authority, and the owner or operator shall comply with the promulgated standard by the compliance date in the promulgated standard.

(b) If the Administrator promulgates an emission standard under section 112(d) or section 112(h) of the Act or the permitting authority makes a determination under section 112(j) of the Act that is applicable to a stationary source or group of sources which was deemed to be a constructed or reconstructed major source under this subpart and has been subject to a prior case-by-case MACT determination pursuant to § 63.43, and the owner and operator obtained a final and legally effective case-by-case MACT determination prior to the promulgation date of such emission standard, then the permitting authority shall (if the initial title V permit has not yet been issued) issue an initial operating permit which incorporates the emission standard or determination, or shall (if the initial title V permit has been issued) revise the operating permit according to the reopening procedures in 40 CFR part 70 or part 71, whichever is relevant, to incorporate the emission standard or determination.

(1) The EPA may include in the emission standard established under section 112(d) or section 112(h) of the Act a specific compliance date for those sources which have obtained a final and legally effective MACT determination under this subpart and which have submitted the information required by § 63.43 to the EPA before the close of the public comment period for the standard established under section 112(d) of the Act. Such date shall assure that the owner or operator shall comply with the promulgated standard as expeditiously as practicable, but not longer than 8 years after such standard is promulgated. In that event, the permitting authority

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Air

Guidelines for MACT Determinations under Section 112(j) Requirements

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ABSTRACT

Section 112(j) of the Clean Air Act as amended in 1990 requires owners or operators of major sources to apply for a Title V permit should the Environmental Protection Agency fail to promulgate emission standards for an applicable source category within 18 months after the date specified in the regulatory schedule established through Section 112(e) of the Act. The Title V permit that is issued must require the owner or operator to meet a maximum achievable control technology (MACT) emission limitation for all hazardous air pollutant (HAP) emissions within the source category. Regulations to implement Section 112(j) are codified in 40 CFR Part 63, Subpart B. This document provides guidance for complying with these regulations by identifying and evaluating control technology options to determine the MACT emission limitation. In this document, the term "control technology" is defined broadly to be consistent with section 112(d)(2) of the Clean Air Act to include measures, processes, methods, systems or techniques which reduce the volume of, or eliminate emissions of, HAP through process changes, substitution of materials or other modifications; enclose systems or processes to eliminate emissions; collect, capture or treat HAP when released from a process, stack, storage or fugitive emissions

point; are design, equipment, work practice, or operational standards; or a combination of the above.

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LIST OF FIGURES

Introduction

The purpose of this manual is to provide State and local agencies with guidance for establishing the case-by-case maximum achievable control technology (MACT) determinations required by Section 112(j) of the Clean Air Act in the event that EPA should miss the deadline for promulgating a Section 112(d) standard by more than 18 months. As with any guidance, this document does not impose legally binding requirements for either the permitting authority or an owner or operator. For a complete understanding of the regulatory requirements, readers should refer to the General Provisions for National Emission Standards for Hazardous Air Pollutants for Source Categories (40 CFR Part 63, Subpart A) and sections 63.50 through 63.56 implementing the Section 112(j) requirements (40 CFR Part 63, Subpart B).

This manual is divided into seven chapters and four appendices. Chapter 1 of this manual provides an overview of the statutory and regulatory requirements and discusses the procedures for applying for a Notice of MACT Approval. Chapter 2 outlines the criteria a permitting authority should use when evaluating applications as well as possible approaches permitting authorities may use for determining the appropriate level of control for each source. Chapter 3 describes a process for selecting control technology that meets the criteria discussed in

Chapter 2. Chapter 4 provides a detailed discussion on determining the minimum level of control that can be MACT for the source (the MACT floor). Chapter 5 briefly discusses some calculation procedures for the equivalent (MACT) emission limitation. Chapter 6 describes the analysis that may be required to assess the costs of achieving the emission reduction, and any non-air quality health and environmental impacts and energy requirements associated with use of different control options. Chapter 7 discusses sources that may assist in the collection of available information.

Appendix A illustrates examples for defining a MACT-affected emission unit, and selecting a control technology to meet MACT. Appendix B contains the June 6, 1994 Federal Register clarifying EPA's use of the word "average" to determine how an average emission limitation should be computed for existing sources. Appendix C provides a suggested format for the Notice of MACT Approval, which the permitting authority may issue consistent with the requirements in 40 CFR 63.54 of Subpart B. Finally, Appendix D contains the Federal Register notice on the final amendments to Regulations Governing Equivalent Emission Limitations by Permit.

While the examples and methodologies in this guidance attempt to illustrate ways the EPA may determine the emission limitation for the purposes of a national Section 112(d) emission standard, they may not represent the only methodology or they may not be the best methodology for establishing a MACT emission limitation. The methods used to establish an emission standard or case-by-case MACT emission limitation will be highly dependent upon the amount and type of information available, the complexity of the source, and the number of feasible control options. In some instances, a permitting authority's control technology determination procedures may yield the appropriate level of control without specifically following this guidance or making a MACT floor finding. The EPA is less concerned with the actual methodologies used, and more concerned that the outcome requires sources to comply with an emission limitation based on MACT.

Also, throughout this manual, the reader will find that the roles and responsibilities in the case-by-case MACT determination have been delineated between the permitting authority and the permit applicant. This delineation of roles and responsibilities is intended to indicate a lead role, but is not intended to establish any sole responsibilities. Permitting authorities and applicants should recognize that establishing the appropriate level of control is an iterative process that will require on-going communication and exchange of information between the permitting authority and the applicant.

In summary, the EPA encourages State and local agencies to cooperatively use this guidance, methods used by the EPA in developing Section 112(d) MACT standards, and various State control technology determination procedures to establish timely, accurate, and consistent MACT emission limitations.

Chapter 1.0

An Overview of the MACT Determination Process for Section 112(j)

1.1 Overview of Statutory Requirements

Beginning after the effective date of an approved permit program, Section 112(j) of the Clean Air Act as amended in 1990 (the Act) requires an owner or operator of a major source to submit either a new Title V permit application or revise an existing permit if such major source incorporates a source category for which the promulgation deadline for a relevant Section 112(d) or 112(h) standard has been missed by 18 months. The promulgation deadline for each source category was established through the regulatory schedule in accordance with Section 112(e) of the Act. A final regulatory schedule was published on December 3, 1993 in the Federal Register (58 FR 63941). To obtain the most current list of categories of sources to be regulated under Section 112 of the Act, or to obtain the most recent regulation promulgation schedule established pursuant to Section 112(e) of the Act, contact the Office of the Director, Emission Standards Division, Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency (C504-03), Research Triangle Park, North Carolina 27711.

Section 112(j) also requires States or local agencies with approved permit programs to issue permits or revise existing permits for all of these major sources. These permits must contain either an equivalent emission limitation or an alternate emission limitation for the control of hazardous air pollutants (HAP) from the equipment within the source category. An equivalent emission limitation, also referred to as a MACT emission limitation, will be determined on a case-by-case basis by the permitting authority for each source category that becomes subject to the provisions of Section 112(j). The MACT emission limitation will be "equivalent" to the emission limitation that the source category would have been subject to if a relevant standard had been promulgated under Section 112(d) (or Section 112(h)).

In accordance with Section 112(d), the MACT emission limitation will require a maximum degree of reduction of HAP emissions, taking into consideration the costs of achieving such emission reductions and any non-air quality health and environmental impacts and energy requirements. For new sources, the MACT emission limitation will be no less stringent than the emission control that is achieved in practice by the best controlled similar source. For existing sources the MACT emission limitation will be no less stringent than:

> 1. The average emission limitation achieved by the best performing 12 percent of the existing sources (for which the Administrator has emissions information), excluding those sources that have, within 18 months before the emission standard is proposed or within 30 months before such standard is promulgated, whichever is later, first achieved

> a level of emission rate or emission reduction which complies, or would comply if the source is not subject to such standard, with the lowest achievable emission rate (as defined by Section 171 (of the Act)) applicable to the source category and prevailing at the time, in the category or subcategory for categories and subcategories with 30 or more sources; or,
>
> 2. The average emission limitation achieved by the best performing 5 sources (for which the Administrator has or could reasonably obtain emissions information) in the category or subcategory for categories or subcategories with fewer than 30 sources. (Sections 112(d)(3)(A) and (B) of the Act.)

These minimum requirements for the MACT emission limitation for new and existing sources are termed the "maximum achievable control technology (MACT) floor".

An alternate emission limitation is a voluntary emission limitation that an owner or operator of a major source has agreed to achieve through the early reductions program (see 57 FR 61970; December 29, 1992). (This regulation is codified in Subpart D, 40 CFR 63.70.) The alternate emission limitation can be written into the permit in lieu of an equivalent emission limitation only if the source has achieved the required reduction in HAP emissions before the missed promulgation deadline for the relevant Section 112(d) (or 112(h)) standard.

Section 112(j) also requires the EPA to establish requirements for owners or operators and reviewing agencies to carry out the intent of Section 112(j). These regulatory requirements are contained in Chapter 40, Part 63, Subpart B of the <u>Code of Federal Regulations</u>.

1.2 Overview of the Section 112(j) Regulatory Requirements

The owner or operator of a major source is required to apply for a Title V permit or permit revision, when the statutory deadline for a relevant Section 112(d) emission standard is missed by 18 months. The content of applications, details of the application approval process, timing of submittals, reviews, and permit issuance are in sections 63.52 and 63.53 of the Section 112(j) rule.

The application for a case-by-case MACT determination is a two-part process. Part 1 of the application requests very basic information about the affected source; the substantive information required by the permitting authority to make its MACT determination is tied to submittal of the Part 2 application. The application content for a MACT determination is contained in section 63.53. Information available as of the date on which the first Part 2 MACT application is filed for a source in the relevant source category or subcategory in the State or jurisdiction will be considered by the permitting authority in making its case-by-case MACT determination. The definition of "available information" in section 63.51 specifies the type of information and sources of information available to the affected source owner or operator for use in completing the application or to the permitting authority in determining the terms and conditions of case-by-case MACT.

The cutoff date for what information may be considered by the permitting authority is in the context of the development of control technologies that could be considered in the MACT floor determination. The definition does not preclude the permitting authority from considering information that was brought to its attention after the cutoff date through public comment or other means, so long as the information (e.g., control technology) had been developed prior to the cutoff date.

The following is a synopsis of the approval process under several scenarios for existing sources, affected sources, and new affected sources as described in section 63.52 of the rule. This synopsis includes situations where an affected source is subject to Section 112(g) requirements and later becomes subject to Section 112(j) and area sources become major affected sources subject to Section 112(j). This synopsis is provided for information purposes only. To the extent the reader identifies any potential conflicts or errors compared to the actual rule language, the language in Subpart B governs.

Sources in existence at the Section 112(j) deadline:

(1) The owner or operator can reasonably determine the affected source is subject to the Section 112(j) rule and submits the Part 1 application as described under Section 63.53(a) of the rule by the Section 112(j) deadline.

(2) If an owner or operator submits a Part 1 application in error, the State is responsible for notifying them that they are not subject to Section 112(j). (That is, the source is not in a category or subcategory subject to Section 112(j)).

(3) The owner or operator of the affected source who does not submit a Part 1 application is notified by the State that he/she is subject to the Section 112(j) rule and submits the Part 1 MACT application within 30 days of the notification. Owners or operators who can reasonably determine they are subject and do not submit an application may be subject to enforcement action.

(4) The affected source has a Title V permit or application that addresses Section 112(g) emission limitation requirements:

- affected source has a Section 112(g) MACT determination and submits Part 1 MACT application per timing in (1) or (3) above;
- affected source has an application and completes the Title V permit process under Section 112(g). Within 30 days of issuance of the Title V permit containing the Section 112(g) MACT determination, affected source submits the Part 1 MACT application.

Sources that become subject after the Section 112(j) deadline and do not have a Title V permit addressing the Section 112(j) requirements:

(1) Installation at a major source or installation that results in the source becoming a major source, but Section 112(g) is not triggered. The owner or operator submits the Part 1 MACT application within 30 days of startup.

(2) The owner or operator has a Title V permit or application satisfying the requirements of Section 112(g). The owner or operator submits the Part 1 MACT application within 30 days of issuance of the Title V permit that addresses the emission limitation requirements of Section 112(g).

(3) Area source becomes major as a result of change in potential to emit (PTE). Source submits a Part 1 MACT application for a Title V permit or an application for a Title V permit revision within 30 days after such source becomes a major source.

(4) Area source becomes major as a result of a lesser quantity emission rate established by the Administrator. Source submits a Part 1 MACT application for a Title V permit or Title V permit revision within 6 months after such source becomes a major source.

Sources that become subject after the Section 112(j) deadline and have a Title V permit addressing the requirements of Section 112(j):

(1) If the "event" is covered by the permit, then the affected source owner or operator complies with the permit;

(2) If the "event" is not covered by the permit, then the existing source submits a Part 1 MACT application for a revision to the permit within 30 days of beginning construction.

Requests for applicability determinations and for Notice of MACT Approval:

(1) If a source owner or operator is unsure whether any of the above scenarios apply, then he/she may submit a Part 1 MACT application to ask the State for an applicability determination.

(2) Owners or operators of new affected sources can obtain preconstruction review through an application for a Notice of MACT approval under section 63.54 of the rule.

Figures 1 and 2 illustrate the obligations and associated timing requirements of sources subject to Section 112(j) requirements.

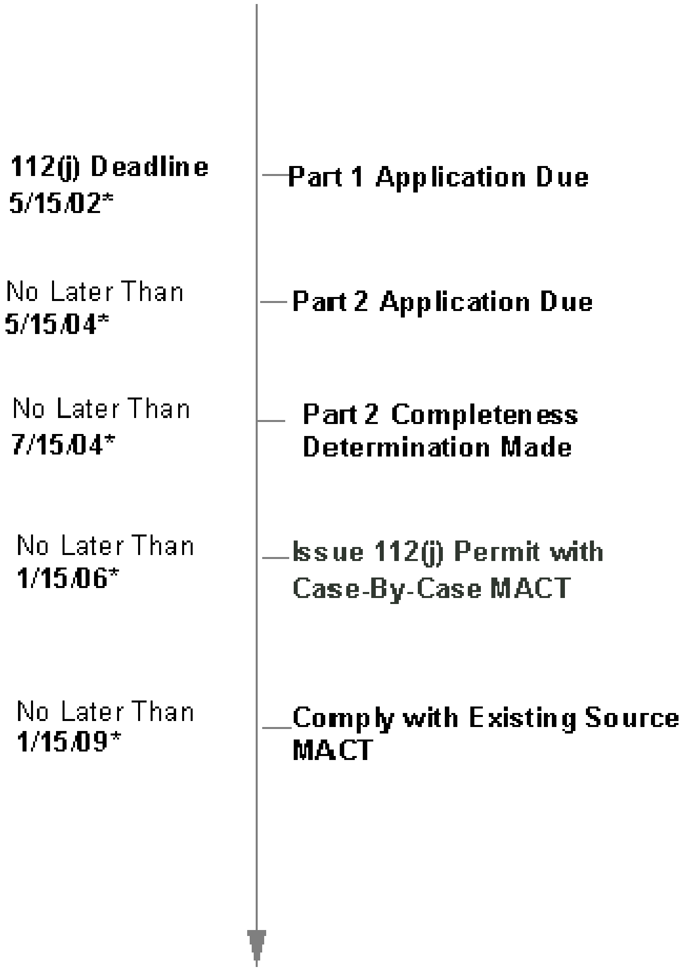


Figure 1. Sources in Existence and Subject to Section 112(j) at Deadline for Source Category (or Subcategory)

* Dates represent latest date possible for compliance

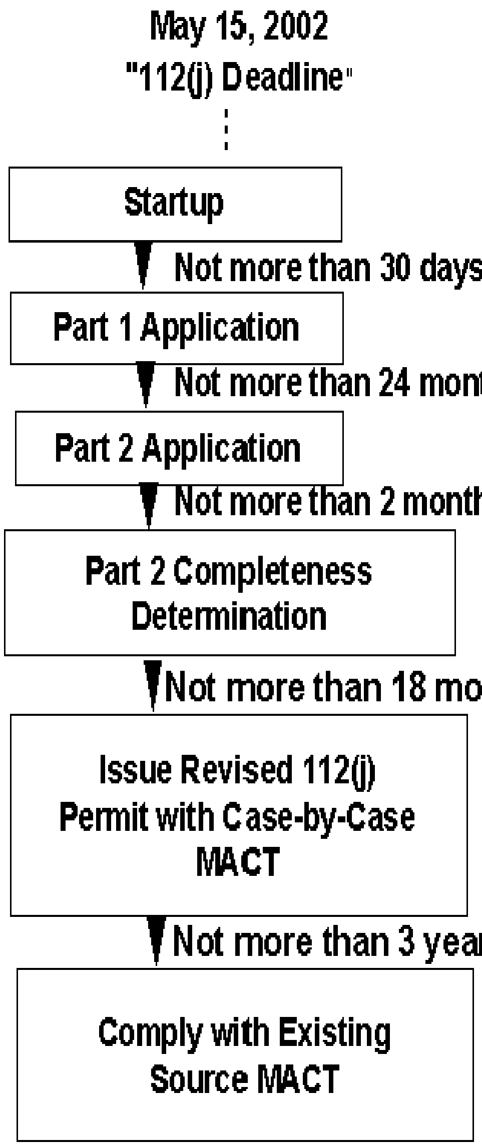


Figure 2. Source Becomes Subject to Section 112(j) After the 112(j) Deadline but before Issuance of Permit

1.3 Affected Source and New Affected Source Review

In some instances an owner/operator may be required to obtain preconstruction review or provide notice of intent to change a source subject to Section 112(j). If an owner or operator is not required to obtain or revise a Title V permit before construction of the new affected source (and has not elected to do so), but the new affected source is covered by any preconstruction or pre-operation review requirements established pursuant to Section 112(g) of the Act, then the preconstruction review requirements under Section 112(g) would fulfill the requirements of Section 112(j). If the new affected source is not covered by Section 112(g), the permitting authority, in its discretion, may issue a Notice of MACT Approval, or the equivalent, consistent with the requirements in 40 CFR 63.54 of Subpart B before construction or operation of the new affected source. Appendix C provides a suggested format for the Notice of MACT Approval. If a Section 112(j) case-by-case MACT determination has been made for such a source, it will include a determination of existing source MACT and new source MACT as well as the applicability of new source MACT. Such a case-by-case determination is the basis for preconstruction review. This process would require owners and operators of major sources to undergo preconstruction review before constructing a new affected source or reconstructing an affected source, if construction is to commence after the Section 112(j) deadline. Details of the requirements for the approval process for affected sources and new affected sources are described in Section 63.52 of Subpart B; preconstruction review procedures for new affected sources are described in Section 63.54. Regardless of the review process, the MACT determination must be consistent with the principles established in Section 63.55.

Chapter 2.0

The MACT Determination

2.1 Criteria for the MACT Determination

The process of determining an equivalent (MACT) emission limitation is called a MACT determination. For MACT determinations under Section 112(j), the MACT emission limitation should be comparable to the emission limitation(s) or requirements that would likely be imposed if a Section 112(d) or Section 112(h) emission standard had been promulgated for that source category. The Clean Air Act sets forth specific criteria for setting a hazardous air pollutant emission standard under Section 112(d) and Section 112(h). These criteria should also be used when establishing the MACT emission limitation under Section 112(j).

Permit conditions created through Section 112(j) of the Act should establish limitations that:

1) Are no less stringent than the MACT floor when a MACT floor can be determined; and,
2) Achieve a maximum degree of HAP emission reduction with consideration to the cost of achieving such emission reductions, and the non-air-quality health and environmental impacts, and energy requirements; and,

3) Limit the quantity, rate, or concentration of HAP emissions on a continuous basis; or,

4) Designate specific design, equipment, work practice, operational standard, or a combination thereof, that achieves a maximum degree of emission reduction, when it is not practicable (economically or technologically) to prescribe a specific numerical emission limitation.

The MACT emission limitation could be expressed as a numerical emission limitation on the total quantity of HAP emissions from the source in tons per year (tpy), a production ratio (e.g., 10 lbs of HAP/100 lbs of polymer), or as a concentration limit (e.g., 10 ppm HAP). The MACT emission limitation could also be a performance standard based on the expected efficiency of MACT in reducing HAP emissions. For example, a source may be required to reduce emissions by 90 percent from a 1990 baseline or to achieve a specified reduction from uncontrolled emission rates. The MACT emission limitation can also be based on a design, equipment, work practice, operational standard, or any combination of these. In some cases, the EPA found that it is appropriate to require a source to use a high efficiency spray gun in the coating process; to conduct a leak detection and repair program for various items of equipment; or to install a floating roof with primary and secondary seals on a storage tank in lieu of establishing a numerical emission limitation.

If an individual hazardous air pollutant is of particular concern, a MACT limitation may also be placed on that pollutant based on the expected level of reduction with MACT in place. Reviewing agencies should consider whether it is appropriate to impose such a limitation on a specific hazardous air pollutant.

In addition to specifying the MACT emission limitation, the permit should establish the terms and conditions that are necessary to make the emission limitation federally enforceable as a legal and practical matter. This involves establishing appropriate operational and/or monitoring parameters to ensure compliance with the MACT emission limitation. The following section discusses compliance provisions in greater detail.

2.2 Compliance Provisions

Each Title V permit and Notice of MACT Approval must contain sufficient testing, monitoring, reporting, and recordkeeping requirements to assure compliance with the MACT emission limitation.

When the permit or Notice of MACT Approval requires an add-on control, operating parameters and assumptions that can be used to determine the efficiency of the device or its emission rate should be specified. For example, a source may have a MACT emission limitation that requires a control device to be installed and operated at a 95-percent emission reduction efficiency. An operational limit on the range of temperatures that the device can be operated under could be sufficient to ensure compliance, if operating the control device within this temperature range ensures that the device achieves a 95-percent destruction efficiency.

If establishing operating parameters for control equipment is infeasible in a particular situation, a short term emission limit (e.g., lbs/hr) would be sufficient provided that such limits reflect the operation of the control equipment, and additional requirements are imposed to install, maintain, and operate a continuous emission monitoring system (CEMS) or other periodic monitoring that yields sufficiently reliable data to determine the source's compliance with the MACT emission limitation.

If parameter monitoring of the process is infeasible due to the wide variety of operating conditions, emission limits coupled with a requirement to calculate daily emissions may be required. For instance, a source could be required to keep the records of the daily emission calculation, including daily quantities and the HAP content of each coating used.

For limitations to be enforceable as a practical matter, the limitations should extend over the shortest practicable time period, generally not to exceed one month. If it is not practicable to place a monthly limit on the source, a longer time can be used with a rolling average period. However, the limit should not exceed an annual limit rolled on a monthly basis.

In addition to conveying practical enforceability of a MACT emission limitation, the Title V permit or Notice of MACT Approval should require testing or monitoring that yields data that are representative of the source's operations and can be used to certify the source's compliance with the terms and conditions of the Title V permit or Notice of MACT Approval. Testing or monitoring must be performed in a manner to ensure that the limitations are achieved at all times, except during startup, shutdown, or malfunction. Such testing or monitoring requirements may be in the form of continuous emission monitoring systems, continuous opacity monitoring systems, or periodic monitoring. If periodic testing is required, the specific EPA-approved method or equivalent method that is to be used should be specified in the permit or notice.

2.3 Approaches to the MACT Determination

When the Administrator fails to promulgate a standard by the promulgation deadline, the EPA intends to make all non-confidential information collected during the development of a source category standard available to the public. If the

Administrator has conducted a MACT floor finding, this analysis will be made available as well. Information will be conveyed either through a Federal Register notice, a background information document, the Technology Transfer Network (TTN), or other available mechanism.

A permitting authority could use several different approaches for the MACT determination process. For example, a permitting authority could wait until all applications for permits are received to determine the equivalent emission limitations that would apply to all of the sources within its jurisdiction. Or, a permitting authority or a group of permitting authorities could conduct a "MACT analysis" based on available information before the first Part 2 MACT application is filed for a source in the relevant source category or subcategory in the State or jurisdiction.

The first approach requires less upfront coordination on the part of the permitting authority and is likely to be used when the EPA fails to collect sufficient information on the source category or subcategory during the standards development process. Once the permit applications are received, information from each application can be compiled to determine the appropriate emissions control level. When this approach is used, the EPA strongly encourages different permitting authorities to share information received through the permit application process.

After the appropriate level of control is determined using the permit application information, permit applicants may need to submit additional information to demonstrate how the required emission reductions will be met so that permit terms and conditions can be developed.

The second approach is most likely to be used when there is a substantial amount of information already available for a source category or subcategory, or when the EPA has already proposed standards for that source category or subcategory. Based on this available information, the permitting authority (or coalition of permitting authorities) could conduct a MACT analysis (See Chapter 3) to determine the appropriate level of control for each source. This control level could be made federally enforceable for all sources in the category through the use of general permits, or each applicant could undergo a separate review in the Title V permitting process. Section 2.5 discusses the concept of general permits in greater detail.

Regardless of the approach taken to issue or revise Title V permits under Section 112(j), permitting authorities are reminded that the equivalent emission limitation is to be determined on a case-by-case basis for each source category or subcategory for which a Section 112(j) MACT determination is required. This determination should be viewed as a "source category-by-source category" determination and terms and conditions in each permit issued should yield an essentially equivalent degree of emission reductions for all affected sources in the category or subcategory.

2.4 Available Information

Section 112(j) states that permits issued pursuant to Section 112(j) shall contain an equivalent emission limitation. This emission limitation is to be "equivalent" to that which the source would have been subject had an applicable Section 112(d) or Section 112(h) emission standard been promulgated. In order to establish an emission limitation that would be equivalent, the permitting authority must determine the equivalent emission limitation with consideration of the MACT floor using available information as defined in 40 CFR 63.51.

It is not necessary for the MACT floor to be determined based on emissions information from every existing source in the source category or subcategory if such information is not available. The permitting authority, however, should check with EPA Regional Offices and EPA Headquarters for any available information that could be used in determining the MACT floor. Once a permitting authority has obtained available information, the MACT floor can be determined using this information if it is representative of the source category or subcategory. For example, suppose there are 100 sources in a source category or subcategory. Control technology X and Y are generally considered to achieve the greatest amount of emission reductions among existing sources. Thirty sources in the category use these technologies. The MACT floor could be determined based on these technologies, even if information was not available on the other seventy sources.

2.5 General Permits

A general permit is a type of Title V permit. A single general permit could be issued by a permitting authority to cover a number of sources. The specific requirements for a general permit are contained in 40 CFR Part 70.6(d).

The general permit can be written to set forth requirements for an entire source category or subcategory, or portion of the source category or subcategory. The facilities that are covered by the general permit, should be homogenous in terms of operations, processes, and emissions. In addition, the facilities should have essentially similar operations or processes and emit pollutants with similar characteristics. The facilities should be subject to the same or substantially similar requirements governing operations, emissions monitoring, reporting, or recordkeeping.

Because the case-by-case determination under Section 112(j) is a source category-by-source category determination of an equivalent emission limitation, the permitting authority could use the general permit as a mechanism to issue Title V permits to the entire source category or subcategory, or specific components within the source category or subcategory. By using this mechanism, a permitting authority would not be required to issue individual permits to sources covered by the general permit. Also, once the general permit has been issued and after opportunity for public participation, EPA review and affected State review, the permitting authority may grant or deny a source's request to be covered by a general permit without further outside review.

Major sources that do not require a specific Title V permit for any other reason, could be covered by the general permit indefinitely. For a major source that already has a Title V permit, the owner or operator can apply for coverage under the general permit, and then incorporate the general permit requirements into the source specific permit through an administrative amendment at permit renewal.

General permits would not be an appropriate mechanism to issue permit conditions if the terms and conditions necessary to establish federal enforceability as a legal and practical matter might vary from source to source within the category. For instance, if a MACT emission limitation restricted emissions from multiple emission points within the source category or subcategory and the number of emission points varied from major source to major source, a general permit may not be appropriate.

Chapter 3.0

The MACT Analysis

For most source categories, the process by which the permitting authority will determine the appropriate level of control involves a number of different determinations. First, the emission points at the major source that are related to the activities and equipment in a source category or subcategory must be identified. There may be a number of emitting activities and equipment at a single major source. In some cases, not all of these emissions are from a single source category or subcategory. Only the emission points in the source category or subcategory undergoing the Section 112(j) MACT determination are subject to control through an equivalent emission limitation.

The collection of equipment and/or activities in the source category or subcategory at the source subject to Section 112(j) is the affected source as defined in 40 CFR 63.2. An affected source may have only one emission unit comprised of all of the emission points; or, it may have several emission units each comprised of some portions of the total number of emission points in the source category or subcategory. In this context the term "emission unit" is equipment or a grouping of equipment for which a floor determination and MACT will be determined. Note that this term has no regulatory or statutory meaning under Section

112(j). It is used here for convenience. Existing source MACT and new source MACT and their respective applicability must be determined for the affected source and new affected source consistent with 40 CFR 63.2, 40 CFR 63.5, and 40 CFR 63.52. The process of establishing the scope of the source category or subcategory, the affected source and new affected source, and the appropriate levels of control by the permitting authority requires ongoing communication and exchange of information between the permitting authority and applicants. This interaction between the permitting authority and applicants is essential in making these determinations.

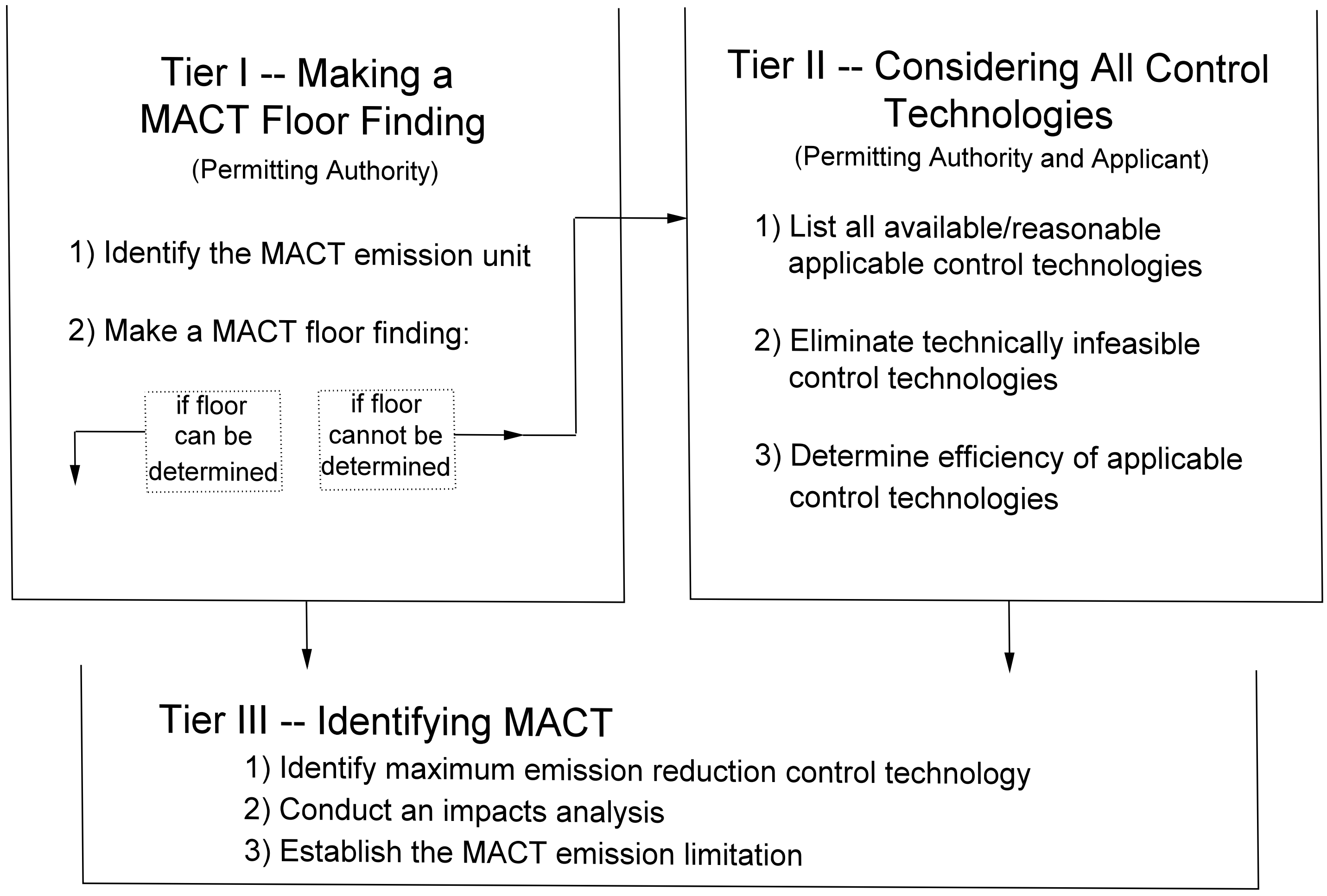
The process by which these determinations are made is termed the MACT analysis. The following sections of this chapter describe a MACT analysis process that EPA has developed to meet the requirements of 40 CFR Part 63, Subpart B.

3.1 Overview of the MACT Analysis Process

The MACT analysis by the permitting authority uses available information to make a MACT floor finding. There are several possible situations that may arise in the course of conducting a MACT analysis. First, the MACT floor could be determined based on emission reductions currently being achieved by other controlled sources. A second possible outcome is that the MACT floor cannot be determined due to the nature of the pollutants emitted from the source, or because of the lack of available data. A third possibility is that the MACT floor could equal "no control" if the group of sources on which the MACT floor determination is based are not currently controlling HAP emissions. In the latter two cases, the EPA believes that a more detailed analysis is required in order to determine the appropriate level of control.

Because of the variety of situations that could arise, the MACT analysis has been divided into three tiers. Figure 3 diagrams the steps for Tier I, Tier II and Tier III of the analysis. A MACT floor finding by the permitting authority is made during Tier I. During Tier II, the permitting authority, in consultation with the applicant, evaluates all commercially

Figure 3. The MACT Analysis



available and demonstrated controls that are reasonably applicable to such source. Tier III uses the information developed in Tier I or Tier II to establish a MACT emission limitation.

This process is presented here as suggested guidance in determining MACT. Permitting authorities are free to use the process with which they are most familiar to determine MACT. If a MACT floor is determined, it is only necessary to complete Tier I and Tier III of the MACT analysis. This analysis compares the costs, non-air quality health and environmental impacts and energy requirements associated with using control technologies that obtain a level of HAP emission reductions that are equal to or greater than the MACT floor. A key assumption is that the Tier I analysis yields sufficient information to conduct the Tier III MACT analysis. If additional information is needed, the permitting authority and the source would develop that information as part of the Tier III analysis.

If, under Tier I, the MACT floor cannot be determined or is equal to "no control," Tier II of the analysis should be completed before moving on to Tier III.

The purpose of Tier II is to identify all commercially available and demonstrated control technologies that are reasonably applicable to such source. Available control technologies include but are not limited to: reducing the volume of, or eliminating emissions of pollutants through process changes, substitution of materials or other techniques; enclosing systems or processes to eliminate emissions; collecting, capturing, or treating pollutants when released from a process, stack, storage, or fugitive emission point; using design, equipment, work practices, or operational standards (including requirements for operator training or certification); or, a combination of any of these methods. The permitting authority in consultation with the applicant is responsible for developing a list of technologies that are reasonably applicable to the source.

Once a list of control technologies that are reasonably applicable to the source is developed, each control technology should be evaluated to consider the costs, non-air quality health and environmental impacts, and energy requirements associated with using each control technology.

In Tier III, the control technology(s) achieving the maximum degree of HAP emission reductions taking into consideration the costs of achieving such emission reductions and the non-air quality health and environmental impacts and energy requirements should be selected as MACT. Once MACT has been selected, a MACT emission limitation(s) should be established by the permitting authority based on the degree of emission reductions that can be achieved through the application of the maximum achievable control technology (MACT). A design, equipment, work practice or operational standard, or combination thereof, may be designated as the MACT emission limitation, if it is not practicable, in the judgement of the permitting authority, to prescribe or enforce a numerical MACT emission limitation.

If an owner or operator wishes to comply with the MACT emission limitation using a control strategy other than the control strategy selected as MACT, then the Title V permit application should be submitted or revised to demonstrate that this alternative strategy achieves the required level of emission reductions.

3.2 A Detailed Look at the MACT Analysis

Tier I - Making a MACT floor finding

Step 1 -- Identify the MACT-affected emission unit(s)

In accordance with the provisions established in 40 CFR 63.53, the owner or operator is required to identify all HAP emission points within the affected source. These emission points will be grouped into emission units (MACT emission units) that will be subject to a MACT determination by the permitting authority.

When a relevant emission standard has been proposed, the scope of the affected source and the emission units should be consistent with the scope of the affected source and the emission units for which MACT was determined in the proposed emission standard, unless an alternative can be adequately supported. When no relevant emission standard has been proposed, the MACT emission unit will be determined on a case-by-case basis. Section 3.3 of this chapter discusses principles for determining the MACT emission unit on a case-by-case basis.

The collection of emission points (and hence the collection of emission units) at the source subject to Section 112(j) that are in the source category or subcategory subject to this subpart is the affected source as defined in 40 CFR 63.2.

Step 2 -- Make a MACT floor finding

Using the available information provided by the EPA, other permitting authorities, and/or the permit applications, a level of HAP emission control that is equal to the MACT floor for each type of emission unit undergoing review should be calculated by the permitting authority according to 40 CFR 63.55.

Chapter 4 discusses three ways to establish a MACT floor: using (1) State and local regulations, (2) control efficiencies, and (3) emission reduction ratios. Use of any of these methodologies to determine the floor depends on the format of available information. It is possible that a hybrid of these approaches may be necessary, or none of the methods may be appropriate given the format of the available information. These methods are provided in this guidance document to demonstrate the types of methodologies that would be appropriate for establishing a MACT floor.

If the MACT floor cannot be determined or if it is equal to "no control", the permitting authority should proceed to Tier II of the analysis.

Tier II - Considering all control technologies

Step 1 -- List all available/reasonable applicable control technologies

Using available information, the permitting authority in consultation with source owners/operators should develop a list of commercially available control technologies that have been successfully demonstrated in practice for similar emission units and that are reasonably applicable to sources in the category or subcategory. Similar emission units are discussed in more detail in Section 3.4 of this chapter.

Step 2 -- Eliminate technically infeasible control technologies

All control technologies that could not be applied to the MACT emission unit because of technical infeasibility should be eliminated from the list. A technology is generally considered technically infeasible if there are structural, design, physical or operational constraints that prevent the application of the control technology to the emission unit. A technology may also be eliminated if the permitting authority deems it unreasonable. A technology is considered unreasonable if the operational reliability and performance have not been demonstrated by approved methods under conditions representative of those applicable to the source for which MACT is being determined.

Step 3 -- Determine efficiency of applicable control technologies

The permitting authority should conduct a detailed analysis of all of the available reasonably applicable control technologies. The efficiency of each control technology in reducing overall HAP emissions should be determined. Generally, MACT has been selected based on an overall reduction of all HAP emissions. However, a permitting authority may also select MACT based on the degree of emission reductions achieved for one or more specific HAPs when the risk to human health and the environment warrants establishing MACT emission limitations specifically for these HAPs. It should also be noted that the application of more than one control technology may be necessary in order to address multiple types of HAP emissions.

Tier III - Identifying MACT

Step 1 -- Identify the maximum emission reduction control technology

When a MACT floor finding is made, the permitting authority will need to use available information to identify the control technology(s) that reduce HAP emissions from the MACT emission units to the maximum extent considering the factors in Section 112(d)(2) of the Act and to a level that is at least equal to or greater than the MACT floor. Consideration can be given to transfer and innovative technologies used to control emissions from other emission units that use technologies that can be applied to the MACT emission unit.

As in Tier II, the permitting authority should conduct an analysis to eliminate any technically infeasible control technologies and to determine the efficiency of applicable control technologies.

While the Clean Air Act establishes that MACT shall be no less stringent than the MACT floor, in establishing MACT, the Administrator must take into consideration "the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements" [section 112(d)(2)]. In some cases, the EPA has developed MACT standards that are more stringent than the MACT floor when the following criteria are met:

(1) The economic impact and incremental cost-effectiveness are not unreasonable;

(2) The standard would control emissions of high risk or highly toxic pollutants, e.g., chromium; or

(3) The standard resulted from a negotiated rulemaking, e.g., the wood furniture NESHAP or the HON equipment leaks standard.

Step 2 -- Conduct an impacts analysis

The control technology that achieves the maximum degree of HAP emission reductions with consideration to costs, non-air quality health and environmental impacts, and energy requirements is MACT. The Act does not provide direction on the significance of one consideration to another. The EPA believes that it is inappropriate to provide specific guidance for determining the amount of consideration that should be given to any one factor. Such decisions will need to be made based on the information available at the time of the MACT determination. See Chapter 6 of this guidance document for a more detailed discussion on the analysis of the costs, non-air quality health and environmental impacts, and energy requirements.

Step 3 -- Establish the MACT emission limitation

The MACT emission limitation established by the permitting authority is based on the degree of emission reduction that can be obtained by the affected source if MACT is applied and is properly operated and maintained. See Chapter 5 for a detailed discussion on the MACT emission limitation and permit conditions.

3.3 Determining the MACT Emission Unit and "Affected Source"

In some cases available information is adequate to support a MACT floor determination for the grouping of equipment and activities comprising the affected source. However, in some cases the EPA has found it necessary to evaluate smaller groupings of equipment and activities for the purpose of the MACT floor and MACT determination. This smaller grouping is referred to herein as a MACT emission unit.

There are four basic principles to follow when designating the MACT emission unit. The principles can be summarized as follows: 1) When a relevant Section 112(d) or Section 112(h) standard has been proposed, the permitting authority should refer to the relevant standard to determine the MACT emission unit; or, (2) The EPA's Office of Air Quality Planning and Standards should be consulted to determine if a suggested method for grouping affected emission points is available; or, (3) When a specific piece of equipment is designated as a source category or subcategory on the source category or subcategory list, the MACT emission unit is that piece of equipment or apparatus; or, (4) Emission points should be combined into a single MACT emission unit when the combination of points leads to a much more cost-effective method of control, and achieves a greater degree of emission reductions when compared to point-by-point compliance.

The best indicator of how a source category or subcategory may be regulated by a future promulgated relevant standard may be found in the proposed standard. For this reason, the EPA believes that permitting authorities should first consider the guidelines in the proposed standard to determine the MACT emission unit for a Section 112(j) MACT determination. In addition, although there may be no proposed standard for the source category or subcategory, information on the source category or subcategory may have been collected which allows the EPA to recommend a specific method for determining the emission unit for a Section 112(j) MACT determination. Therefore, the EPA should be consulted before attempts are made to define the MACT emission unit on a case-by-case basis.

When a source category or subcategory is associated with a piece of equipment or apparatus specifically listed on the source category or subcategory list, that piece of equipment or apparatus is the MACT emission unit. The source category or subcategory list contains sources that are defined at various levels of complexity: from an integrated manufacturing or process operation to an individual piece of equipment. In developing the source category or subcategory list, the EPA determined that some individual pieces of equipment may be co-located with other HAP-emitting equipment that, independently or collectively, have the potential to emit major amounts of HAPs. For example, under the fuel combustion industrial grouping, stationary internal combustion engines are listed as a source category or subcategory. When a source category or subcategory is designated by a single type of apparatus, the EPA believes that the intent is for emission limitations and requirements to be placed on that specific piece of equipment. As such, if a Section 112(j) determination is conducted for any one of these source categories or subcategories, the specific piece of equipment or apparatus should be designated as the MACT emission unit.

A single emission point such as a storage tank could be considered the MACT emission unit. By contrast, emission points from a distillation column, a condenser and distillate receiver could be consolidated into one emission unit. Larger groupings of emission points may be appropriate when a single control technology can be used to control the aggregation or when a pollution prevention or waste reduction strategy is considered. For instance, the entire wastewater treatment operation within the source category or subcategory could be considered one emission unit. Collectively, a single steam-stripper could be used at the beginning of the operation to remove HAPs from the wastewater and prevent downstream emissions from occurring. Another example is illustrated with a surface coating operation. Rather than individually controlling the emissions from a spray booth, flash-off area, and bake oven, switching to a water-based paint could reduce emissions from all of these emission points.

Another reason to combine affected emission points into a single emission unit is that many major sources are already subject to regulation under 40 CFR Part 60. In promulgating these standards, "affected facility" definitions were developed to designate the apparatus to which a standard applies. It may make sense to use these same boundaries to designate the "MACT emission unit" subject to a MACT determination. It should be noted that a particular piece of apparatus or equipment should not be excluded from a MACT determination because of an applicability "cut-off" established under a Part 60 regulation.

Emission points could be consolidated into an emission unit that is as large as the source category or subcategory boundary for several reasons. First, the information that is available to calculate the MACT floor may only apply to the source category or subcategory as a whole, not individual points within the category. Also, the operations of some source categories are quite variable. Either the nature of the process requires a large latitude of flexibility in establishing the emission unit that should be controlled, or the types of facilities within the category are so diverse that it only makes sense to compare the existing sources on a source category or subcategory wide level. In these instances, a source category or subcategory wide MACT emission unit could allow some emission points to be under-controlled while others are controlled to a level that would exceed the level of control that would be placed on that individual point through the application of MACT.

Permitting authorities are cautioned that, consistent with the EPA's emissions averaging decisions, as prescribed in 40 CFR 63.150, it would be generally inappropriate to include emission points associated with equipment leak emissions together with other types of emission points in a MACT emission unit until the EPA determines that emissions can be appropriately estimated for this purpose.

There are some situations that would make the combination of emission points unreasonable. For example, the combination should not be done in order to generate an emission unit that is so unique that it precludes comparing the emission unit to other sources in the source category or subcategory. In other cases, the EPA has established thresholds for types of emission points within a MACT emission unit, which define whether such points are required to be further controlled in order to meet MACT. For example, as illustrated by Group 2 sources (40 CFR Part 63, Subpart G), the MACT floor for smaller or more dilute sources may be no control, and nothing more stringent than the floor may be justified.

Determining the MACT emission unit on a case-by-case basis is a complex undertaking. While this document includes this step as a separate component of the Tier I approach, in actual practice the identification of methods to control specific groups of emission units and the identification of control technology options will be integrated processes. Some aggregations of emission points may be inappropriate because the information available to calculate the MACT floor would dictate combining emission points into certain emission units, or because controls applied to the unit would not achieve a MACT level of control when compared to point-by-point compliance or some other combination of emission units. Appendix A provides an example of ways in which available control technologies would affect the aggregation of emission points into an emission unit.

3.4 Similar Emission Units

The permitting authority should evaluate control technologies used by similar emission units in other source categories during Tier II. Whether control technologies from other source categories should be considered in the MACT analysis depends on whether the emission unit is "similar". At least two questions should be answered to determine if an emission unit is similar: 1) Do the two emission units have similar emission types, and 2) Can the emission units be controlled with the same type of control technology. If the two emission units do have similar emission types and are controllable to approximately the same extent with the same control technologies, then the two emission units can be considered similar for the purposes of a case-by-case MACT determination under Section 112(j).

For example, suppose Section 112(j) applies to the captan production source category or subcategory (a source listed on the source category or subcategory list), and a major source produces captan with equipment using product accumulation vessels (tanks) and additional pipes, pumps, flanges and valves to direct the product to the tanks. During Tier I of the MACT analysis, it is determined that there are no regulations controlling HAP emissions from pumps, etc. within this source category or subcategory. There is also not enough emission information available on other emission units within the source category or subcategory to calculate a MACT floor. During Tier II of the analysis, it is discovered that the Synthetic Organic Chemical Manufacturing Industry (SOCMI) source category or subcategory is currently subject to regulations controlling equipment leaks. Because the pipes, pumps, and flanges all have equipment leak emissions and can be controlled to the same extent by a leak detection and repair program, such equipment in the SOCMI source category or subcategory would be considered similar emission units. The regulations for SOCMI equipment leaks should be considered for the control of the MACT emission unit during Tier II of the analysis. When determining the existing source level of control, identification of a similar emission unit does not mean that the controls will automatically be applied to the MACT emission unit. Costs, non-air quality health and environmental impacts, and energy requirements should be used to assess the technologies ability to meet MACT criteria.

Also during Tier I of the analysis, it may be determined that the best controlled tank within this source category or subcategory does not have state-of-the-art controls. Yet, tanks from outside the source category or subcategory storing similar organic liquids use state-of-the-art controls vented to an emission control device. The controls used on these tanks would be considered in establishing MACT.

After identifying MACT, the permitting authority proceeds to establish the MACT emission limitation, monitoring, and recordkeeping as outlined previously.

3.5 Subcategorization

When the source category list was developed, sources with some common features were grouped together to form a "category". During the standard-setting process, the EPA has found it appropriate to combine several categories or to further divide a category into subcategories. The EPA chose to establish broad source categories at the time the source category list was developed because there was too little information to anticipate specific groupings of similar sources that are appropriate for defining MACT floors for the purpose of establishing emission standards.

The broad nature of some source category descriptions may pose some difficulty in establishing an appropriate MACT emission limitation for a MACT emission unit on a case-by-case basis. Subcategorization within a source category for the purposes of a case-by-case MACT determination should be considered when there is enough evidence to clearly demonstrate that there are air pollution control engineering differences. Criteria to consider include process operations (including differences between batch and continuous operations), emissions characteristics, control device applicability and costs, safety, and opportunities for pollution prevention. When separate subcategories are established, the MACT floor and MACT are then determined separately for each such subcategory.

Chapter 4.0

The MACT Floor Finding

During Tier I of the MACT analysis, the permitting authority will make a MACT floor finding if there is enough information to determine an emission control level that is at least equal to the MACT floor. If a MACT floor cannot be determined due to the nature of the pollutant or process, or there is not enough emissions information to compute a MACT floor, then the analysis in Tier II would be completed. Similarly, if the MACT floor equals "no control," the permitting authority should proceed to the Tier II analysis.

The Act specifically directs EPA to consider the "average emission limitation" achieved in practice to establish the MACT floor for existing sources. Section 4.1 of this chapter discusses calculation procedures for determining an "average emission limitation".

Using the calculation procedures discussed in Section 4.1, this chapter explains four approaches for determining a MACT floor. If the emissions information is available, the first three methods should be considered before the permitting authority concludes that a MACT floor cannot be determined. The three emissions-based methods include using: (1) existing State and local air toxic control regulations; (2) control efficiency ratings; or (3) emission reduction ratios.

A fourth method, the technology approach, can be used when insufficient emissions data are available to determine an average emissions limitation.

The first method compares air pollution regulations in different States. The second method is applicable when the control technologies under consideration can be assigned an efficiency rating for HAP emission reductions. This is most likely to occur with add-on control devices. The third method can be used for add-on control devices, work practices, recycling, reuse or pollution prevention strategies. Depending on the format of available information, a hybrid of the three approaches may be necessary. The fourth method involves determining which technology is being used by the best performing sources in the category as defined in sections 112(d)(3)(A) and (B) and then determining the emissions limit that the technology is capable of achieving in practice on a continuous basis. Later in this chapter each of these methods is discussed in greater detail.

4.1 Calculation of the MACT Floor

Section 112(d) of the Act instructs the EPA to set emission standards for new sources based on the emissions control achieved in practice by the best controlled similar source and to set emission standards for existing sources based on an average emission limitation achieved by the best performing 12 percent of existing sources or best performing five sources in the source category or subcategory for categories with fewer than 30 sources. For new sources, the direction provided by the Act is relatively clear. For existing sources, further clarification is required by the EPA to determine how an average emission limitation should be computed.

The word "average" can have several different meanings, including arithmetic mean, median, and mode. As stated previously, the EPA published a Federal Register notice describing these methods of determining the average as well as other common sense considerations at 59 FR 29196 et.seq., June 6, 1994. A copy of this notice is contained in Appendix B of this document.

The following examples illustrate the average as represented by the mean, median, and mode.

Example 1

The following emission limitations are representative of the best performing 12 percent of existing sources:

% reduction

95
95
93
93
92
88

Average emission limitation defined by the mean =

644/7 = 92%

88

Total 644

Number of sources in the best performing 12% = 7

In this case the MACT floor would be 92%.

Under some circumstances the arithmetic mean results in a number that may not correspond to the application of a specific control technology. If there is a large discrepancy between the amount of emission reductions that can be achieved by available control options, other factors should be considered to determine the MACT floor. This is illustrated with the following example:

Example 2

An arithmetic mean is computed for the best performing 12 percent of storage tanks. There are 10 sources among the best performing 12 percent of storage tanks. Two tanks are controlled at 99 percent, and the remaining 8 tanks are not controlled. The emissions limitations considered in the floor calculation are:

% reduction

99
99
0
0
0
0
0
0
0
0

average emission limitation = 19.8% reduction

Total 198

Number of sources in top 12% = 10

In this example, no technology corresponds to 19.8-percent control, and it might be inappropriate to elevate the MACT floor to 99-percent control.

If there is a large discrepancy between the amount of emission reductions that can be achieved by available control options, the median should be used in lieu of the arithmetic mean to determine the average emission limitation equal to the MACT floor. A median is the value that falls in the middle of a set of numbers when those numbers are arranged in an increasing order of magnitude; in other words, there will be an equal number of values above and below the median. If the middle falls between two values, the median is equal to the arithmetic mean of those two numbers. This situation will occur when there is an even number of values in the set of numbers. In this example, the median would be 0-percent reduction, and this could be selected as the MACT floor.

However, if there is a large discrepancy between the control technologies used to establish a median such that no technology could realistically obtain a reduction close to the median, the mode should be used to calculate the MACT floor. A mode is the most frequent occurrence among a set of data. In Example 1, there are two modes, 95-percent and 88-percent emission reductions. In Example 2, the mode would be equal to 0-percent emission reduction. When there is more than one mode in the data set, the MACT floor should be based on the least degree of emission control. However, the existence of more than one mode may be an indicator that the MACT should be established at a level of control more stringent than the MACT floor.

The mode may also be used as a method to compute an average emission limitation if the emissions data for a source category or subcategory are not numerically based. This situation could occur if sources were regulated by several different equipment or work practice standards. Unless a specific level of emission reduction can be associated with each different standard or unless the standards can be ranked in some order of increasing level of control, an arithmetic mean and median cannot be calculated. A mode could be used if one of the control options is used more frequently by the best performing 12 percent of existing sources. For example:

Example 3

There are 44 tanks in the source category or subcategory. Five sources are among the best performing 12 percent of existing sources. These five tanks are subject to the following regulations in the source category or subcategory:

3 of the 5 must be covered and vented to a carbon canister;

2 of the 5 must use a fixed roof.

The mode would be to cover and vent the tank to a carbon canister.

4.2 Method 1 - Computing the MACT Floor Using Existing State and Local Regulations

The steps for computing a MACT floor using this method are as follows:

Step A: Conduct a geographical survey.

Determine the total number of existing similar emission units in the source category or subcategory, and conduct a survey to determine the geographical location of these similar emission units. Group the emission units according to the State or locality in which they are located.

Step B: Review State or local air pollution regulations.

Review the different State or local air pollution control regulations that are applicable to the emission unit in each State or locality where an emission unit is located.

Step C: Rank the State or local air pollution regulations.

For the State and local regulations identified in Step B, rank the regulations in order of stringency. The regulations that require the greatest level of control should be listed first.

Step D: Rank emission units.

Determine the total number of emission units and the number of emission units complying with each stringency level. Based on the level of regulation stringency, rank the emission units in order from most stringent to least stringent.

Step E: Make a MACT floor finding.

Based on the distribution of sources in the various States and the stringency of the respective State requirements, it may be possible to construct a database that would support a MACT floor determination as described in Section 4.1. Note that a determination must also be made that sources in the States actually achieve the required control levels.

4.3 Method 2 - Computing the MACT Floor Using Control Efficiency Ratings

To use this method to calculate the MACT floor, the permitting authority will evaluate emission units that use add-on control devices or other methods whose HAP control efficiencies have been clearly demonstrated in practice. The MACT floor and MACT emission limitation can be computed as follows:

Step A: Determine HAP emission reduction efficiency for each control device.

For each emission unit in the source category or subcategory, the ability of each control technology to reduce HAP emissions should be determined as a percentage of reduction efficiency. Acceptable methods for determining the efficiency rating are:

(1) Federal and State enforceable permits limits on operation of the control technology, where compliance has been demonstrated;

(2) Actual reported efficiencies.

In addition vendor data of demonstrated performance achieved in similar service may be used in conjunction with good engineering judgement.

Step B: Calculate the MACT floor using the methodology in Section 4.1.

4.4 Method 3 - Computing the MACT Floor Using Emissions Reduction Ratios

The emission reduction ratio is a fraction of uncontrolled emissions to controlled emissions. The MACT floor is computed using the emission reduction ratios. To compute the emission reduction ratio for each emission unit, the permitting authority must review emissions data or other information to determine uncontrolled and controlled emissions levels for these units. The step-by-step process is detailed below.

Step A: Compute an uncontrolled emission level for each emission unit.

The uncontrolled emission level for an emission unit is the maximum amount of HAP that could be emitted from the emission unit using current design specifications at full capacity utilization in the absence of controls.

Step B: Compute a controlled emission level for each emission unit.

The controlled emission level is the maximum amount of HAP that could be emitted from the emission unit under the source's current design specification and at full capacity utilization taking into consideration the application of federally enforceable controls. Ideally, a controlled emission level should be computed for all emission units, even when a single uncontrolled emission level is used. However, if only general information is known about the types of control technologies that are being used in practice, a controlled emission level could be estimated for each control scenario. Then a controlled emission level for each emission unit would be assigned based on the types of controls that major sources use. Readers should review Chapter 5 for more information on controlled emission levels.

Step C: Compute the emission reduction ratio for each emission unit.

The emission reduction ratio for each emission unit can be computed using the following formula:

$$\frac{\text{Uncontrolled Emission Limit - Controlled Emission Limit}}{\text{Uncontrolled Emission Limit}}$$

Step D: Determine the MACT floor using the methodology in Section 4.1.

4.5 Technology Approach

The technology approach is used when insufficient emissions data are available to determine an average emission limitation. Under this approach, EPA determines which technology is being used by the average of the best performing 12 percent of sources in the category, and then determines the average emission limit that this technology is capable of achieving in practice on a continuous basis. Available emissions data are used to assign a performance value for each emission control identified (percent removal, outlet grain loading, etc.). The MACT floor calculation is performed based on these performance values. Typically, a median is used rather than the arithmetic average since an arithmetic average generally would not correspond to any given control. The following example illustrates this approach.

A source category emitting metal HAP is comprised of 500 sources. A survey of the sources finds that 300 facilities use cyclones to control HAP emissions, 150 facilities use wet scrubbers, and 50 facilities use fabric filters. Based on available emissions data, it is determined that cyclones are 25-percent efficient at removing HAP emissions, wet scrubbers are 75-percent efficient, and fabric filters are 99-percent efficient. The best controlled 12-percent of sources would include 10 sources with wet scrubbers and 50 sources with fabric filters. The median corresponds to fabric filters. Therefore, fabric filters would be identified as the MACT floor technology, and an emission limitation would be set based on the available performance data for fabric filters.

4.6 Other Methods to Compute the MACT Floor

As future MACT standards are proposed or promulgated for different source categories, more methods for determining the MACT floor could be developed. The reader is referred to the June 6, 1994 (59 FR 29196 et.seq.) in Appendix B and other Federal Register notices to locate any other methods for calculating the MACT floor that have been approved by the EPA and used in developing a MACT standard under Section 112(d) or 112(h) of the Act.

Chapter 5.0

The MACT Emission Limitation and Permit Conditions

5.1 MACT Emission Limitation

The MACT emission limitation established by the permitting authority is based on the level of emission reductions that can be obtained by the affected source when MACT is applied and properly operated and maintained. The MACT emission limitation should be based on an overall reduction of all HAP emissions. The MACT emission limitation may need to account for differing kinds of equipment within the affected source and may include emission averaging provisions to allow such equipment to achieve MACT in the most cost-effective manner possible. The permitting authority may establish a MACT emission limitation for an individual HAP when the risk to human health and the environment warrants such an emission limitation. If it is not practicable to establish a specific numerical or efficiency limitation, then a specific design, process, or control technology should be designated as the MACT emission limitation. For example, a floating roof with a primary and secondary seal on a storage vessel or an equipment leak detection and repair practice could be determined as MACT.

Determining the expected emission reductions from an add-on control may require some engineering judgement. In some instances, the add-on control may achieve different levels of reduction efficiency even when it is applied to the same type of emission unit. Lower efficiency ratings may be due to different operational parameters or poor maintenance practices. The MACT emission limitation should be based on the level of control that the technology is likely to obtain for all emission units operating under good operational and maintenance practices.

Chapter 4 of this manual describes possible methodologies for calculating a MACT floor. It is likely that the regulatory format of the MACT emission limitation will be similar to the format of the MACT floor. For instance, if the MACT floor is computed to be a limit of 0.30 lbs/ton of feed, the regulatory format of the MACT emission limitation is also likely to be expressed as lbs/ton of feed. The following sections provide guidance on calculating the MACT emission limitation for a source category or subcategory. These sections also discuss how a permitting authority can determine what amount of control an individual source needs to achieve the required reductions.

When control efficiencies are used to establish a MACT floor, the MACT emission limitation could be expressed as this efficiency. In other words, all sources could be required to reduce emissions by some percent (i.e., 90-percent reduction). Additional terms and conditions would be necessary to make this practically enforceable, but such an emission limitation may be appropriate when all emission units are operated relatively homogeneously within the source category or subcategory. For other source categories it may be appropriate to convert this efficiency rating into another format. This can be accomplished by multiplying the efficiency of MACT by the uncontrolled emission level of the emission unit as follows:

$$\begin{array}{c}\text{MACT}\\ \text{Emission}\\ \text{Limit}\end{array} = \text{Uncontrolled Emission Level} * \text{MACT efficiency}$$

The uncontrolled emission level for an emission unit is the maximum amount of HAP that could be emitted from the emission unit using current design specifications at full capacity utilization in the absence of controls. It could be computed using a variety of different formats, i.e. tons/yr, lbs/hr, lbs/ton, etc. The following sources of information may be acceptable:

(1) Engineering calculation using material balance or emission factors;
(2) Actual emission data from similar emission units;
(3) Average annual hourly emission rate multiplied by hours of operation;
(4) Emission limits and test data from EPA documents, including background information documents;

(5) State emission inventory questionnaires for comparable sources;

(6) Federal or State enforceable permit limits; or,

(7) For equipment leaks use, "Protocols for Equipment Leak Emission Estimates," EPA-453/R-93-026.

The selection of the uncontrolled emission level will likely require some engineering judgement on the part of the permitting authority. Typical throughputs, flow rates, concentrations, etc. should be used to estimate a uncontrolled emission level that can be applied to the source category or subcategory.

The definition of a control technology includes the use of pollution prevention and source reduction strategies. The permitting authority should take into consideration the use of such control measures when computing the uncontrolled emission level for an emission unit. For example, some MACT emission units in the source category or subcategory may use a high VOC solvent as a process input to the emission unit. Other units may use a lower VOC solvent as a process input to the same type of emission unit. No distinction in the type of process inputs have been made in designating the emission unit. The MACT for this emission unit is identified as control technology X. If this control technology was determined to have a control efficiency rating of 90 percent, then the current design specifications for each emission unit in the category would require all sources to reduce emissions by 90 percent. However, this would not account for the different baseline emissions from different emission units in the source category or subcategory. By calculating the uncontrolled emission level for all emission units in the category based on the high VOC process input, emission units with inherently lower potentials to emit can take credit for the emission reduction in the controlled emissions calculation and the calculation of additional required control.

5.2 Alternative Ways to Comply

Once the permitting authority determines the MACT emission limitation, the applicant will determine a control strategy that allows the affected source to meet MACT. In many cases, this will be through the application of the MACT technologies. However, in some cases, the emission unit at the major source may already be controlled to some extent with an existing control technology. The owner or operator could demonstrate that using additional control strategies in combination with existing controls will allow the emission unit to achieve the required emission reductions. For instance, an emission unit may currently be controlled with a baghouse. The MACT emission limitation for the emission unit may be based on use of an electrostatic precipitator. The emission unit may be able to meet the MACT emission limitation by installing a series of baghouses in lieu of the electrostatic precipitator.

Owners or operators are reminded that the application of a case-by-case MACT to an affected source does not exempt that owner or operator from complying with any future emission standards affecting that affected source. The applicability and impact of subsequently promulgated MACT standards is addressed in 40 CFR 63.56. Owners or operators may wish to consider these factors when selecting a control technology to meet the MACT emission limitation.

5.3 Applicable Monitoring, Reporting and Recordkeeping, and Compliance

The permitting authority should identify monitoring parameters in consultation with the applicant to assure compliance with the MACT emission limitation. However, the permitting authority is ultimately responsible for these monitoring parameters, as well as reporting and recordkeeping requirements at permit issuance. Section 2.2 of Chapter 2 discusses compliance provisions in greater detail.

Chapter 6.0

Costs, Non-Air Health and Environmental Impacts, and Energy Impacts

Section 112(d) of the Act specifies that if control technology alternatives are being considered to establish an emission standard that would result in emission limitations more stringent than the emission "floors," they must be evaluated by considering costs, non-air quality health and environmental impacts, and energy requirements associated with the expected emission reductions.

The costs, non-air quality health and environmental impacts, and energy requirements discussed below are illustrative only and are not intended as an exclusive list of considerations for MACT determinations. Some of these factors may not be appropriate in all cases, while in other instances, factors which are not included here may be relevant to the MACT determination. The discussion does not address the evaluation of each factor nor the weighing of any factor relative to another. Such determinations should be made on a case-by-case basis by the owner/operator and permitting authority. For the purpose of this guidance, terms such as "emission control system" or "MACT system" refer to design, equipment, or operating standards and inherently less polluting processes, as well as add-on control equipment.

In general, the impact analyses for MACT determinations should address the direct impacts of alternative control systems. Indirect energy or environmental impacts are usually difficult to assess, but may be considered when such impacts are found to be significant and quantifiable. Indirect energy impacts include such impacts as energy to produce raw materials for construction of control equipment, increased use of imported oil, or increased fuel use in the utility grid. Indirect environmental impacts include such considerations as pollution at an off-site manufacturing facility that produces materials needed to construct or operate a proposed control system. Indirect impacts generally will not be considered in the MACT analysis since the complexity of consumption and production patterns in the economy makes those impacts difficult to quantify. For example, since manufacturers purchase capital equipment and supplies from many suppliers, who in turn purchase goods from other suppliers, accurate assessment of indirect impacts may not be possible. Raw materials may be needed to operate control equipment, and suppliers of these resources may change over time. Similarly, it is usually not possible to determine specific power stations and fuel sources that would be used to satisfy demand over the lifetime of a control device.

In most cases, duplicative analyses are not required in preparing the MACT impact analyses. Any studies previously performed for Environmental Impact Statements, air permits, water pollution permits, or other programs may be used when appropriate. The permitting authority also may consider any special economic or physical constraints that might limit the application of certain control techniques to an existing emission unit, such as retro-fitting costs that would not be borne by a new unit, or the remaining useful life of the emission unit. The result may be that the level of control required for an existing emissions unit may not be as stringent as that which would be required if the same unit were being newly constructed at an existing plant or at a "greenfield" facility. However, in no event shall the level of control yield an emission limit less stringent than the MACT floor when information is available to compute the MACT floor.

6.1 Cost Impacts

Cost impacts are the costs associated with installing, operating, and maintaining alternative emission control systems (add-on emission control devices or process changes.) Normally, the submittal of very detailed and comprehensive cost data is not necessary. Presentation of the quantified costs of various emission control systems (referred to as control costs,) coupled with quantities of HAP emission reductions associated with each of the emissions control systems, is usually sufficient.

Once the control technology alternatives and emission performance levels have been identified, total capital investment and total annual cost should be developed. Total capital investment (purchased equipment plus installation) and total annual costs of each emission control system should be presented separately. Total annual costs are comprised of operation and maintenance costs ("direct annual costs",) administrative charges ("indirect annual costs"), plus overhead, taxes, insurance, and capital recovery costs minus recovery credits (credit for product recovery and by-product sales generated from the use of control systems and other emission reduction credits.) These costs should be reported in equal end-of-year payments over the time of the equipment. Total annual costs should be reported on an overall basis, as well as an incremental basis. The various emission control systems should be presented or arrayed in terms of increasing total annual cost. The incremental annual cost of a particular emission control system is the difference in its cost and the cost of the next less stringent control.

A method for determining the acceptability of control costs is the comparison of the cost effectiveness of alternative control systems. Average cost effectiveness is the ratio of total annual costs (calculated using the above guidelines) to the total amount (tons or Mg) of HAP removed. Incremental cost effectiveness is calculated using the same procedure as outlined for calculating incremental annual cost. Generally, cost-effectiveness values falling within the range of previously acceptable MACT decisions are considered acceptable. Therefore, consistency with the relative cost, or cost effectiveness, of a past MACT determination for a similar source is an indication that such a cost is reasonable for the MACT determination in question.

For most MACT determinations, a cost analysis focusing on incremental cost effectiveness of various MACT alternatives is sufficient. The analysis should include and distinguish the various components used to calculate the incremental cost effectiveness of the control alternatives (i.e., lifetime of the equipment, total annual costs, tons of total HAP removed, etc.).

If there is reason to believe that the control costs place a significant burden on the entity being controlled, then the cost analysis should include financial or economic data that provide an indication of the affordability of a control relative to the source. For example, if the per unit cost is a significant portion of the unit price of a product or if the economic status of the industry is declining, then the cost analysis should present the relevant economic or financial data. Financial or economic data should include parameters such as after-tax income or total liabilities.

6.2 Environmental Impacts

The environmental impacts concentrate on collateral environmental impacts due to control of emissions of the pollutant in question, such as solid or hazardous waste generation, discharges of polluted water from a control device, visibility impacts (e.g., visible steam plume), or emissions of other air pollutants. The permitting authority should identify any environmental impacts associated with a control alternative that has the potential to affect the selection or rejection of that control alternative. Some control technologies may have potentially significant secondary environmental impacts. Scrubber effluent, for example, may affect water quality and land use, and, similarly, technologies using cooling towers may affect visibility. Other examples of secondary environmental impacts could include hazardous waste discharges, such as spent catalysts or contaminated carbon. Generally, these types of environmental concerns become important when sensitive site-specific receptors exist or when the incremental emissions reduction potential of one control option is only marginally greater than the next most effective option.

The procedure for conducting an analysis of environmental impacts should be made based on a consideration of site-specific circumstances. In general, the analysis of environmental impacts starts with the identification and quantification of the solid, liquid, and gaseous discharges from the control device or devices under review. Initially, a qualitative or semi-quantitative screening can be performed to narrow the analysis to discharges with potential for causing adverse environmental effects. Next, the mass and composition of any such discharges should be assessed and quantified to the extent possible, based on readily available information. As previously mentioned, the analysis need only address those control alternatives with any environmental impacts that have the potential to affect the selection or rejection of a control alternative. Pertinent information about the public or environmental consequences of releasing these materials should also be assembled. Thus, the relative environmental impacts (both positive and negative) of the various alternatives can be compared with each other.

Also the generation or reduction of toxic and hazardous emissions other than those for which the MACT determination is being made and compounds not regulated under the Clean Air Act are considered part of the environmental impacts analysis. A permitting authority should take into account the ability of a given control alternative for regulated pollutants to affect emissions of pollutants not subject to regulation under the Clean Air Act in making MACT decisions. Consequently, the ability of a given control alternative to control toxic or hazardous air contaminants other than those for which the MACT determination is being made, should be considered in the MACT analysis.

6.3 Energy Impacts

Energy impacts should address energy use in terms of penalties or benefits associated with a control system and the direct effects of such energy use on the facility. A source may, for example, benefit from the combustion of a concentrated gas stream rich in volatile organic compounds; on the other hand, extra fuel or electricity is frequently required to power a control device or incinerate a dilute gas stream. If such benefits or penalties exist, they should be quantified to the extent possible.

In quantifying energy impacts, the direct energy impacts of the control alternative in units of energy consumption at the source (e.g., Btu, Kwh, barrels of oil, tons of coal) should be estimated. The energy requirements of the control options could be shown in terms of total and/or incremental energy costs per ton of pollutant removed. In many cases, because energy penalties or benefits can usually be quantified in terms of additional cost or income to the source, the energy impacts analysis can be converted into dollar costs and, where appropriate, be factored into the cost analysis.

Indirect energy impacts (such as energy to produce raw materials for construction of control equipment) are usually not considered. However, if the reviewing agency determines, either independently or based on a showing by the applicant, that an indirect energy impact is unusual or significant, the indirect impact may be considered. The energy impact should still, however, relate to the application of the control alternative and not to a concern over energy impacts associated with the project in general.

The energy impact analysis may also address the concern over the use of locally scarce fuels. The designation of a scarce fuel may vary from region to region, but in general a scarce fuel is one which is in short supply locally and can be better used for alternative purposes, or one which may not be reasonably available to the source either at the present time or in the near future.

Chapter 7.0

Sources of Information

There are currently several programs under development to house and disseminate toxics information. Some of these programs are designed for specific, narrow purposes, while others are employed in a broader range of uses. Most data collection programs are designed to be compatible with the Aerometric Information Retrieval System (AIRS)/AIRS Facility Subsystem (AFS).

The purpose of this chapter is to present various sources of toxics information which may be of assistance to States and industry in making MACT floor determinations. These sources of toxic information are available in a database format. The EPA believes the requirements of Section 112(j) can be less burdensome to both industry and States by employing a database system to document similar-category sources and provide a bibliography of information to make a sound MACT floor determination. The MACT floor determinations and MACT must be based on data demonstrating performance levels actually achieved in practice by sources. Performance claims, expectations, design plans, etc. should be substantiated by methods representative of those that sources will have to comply with.

Another significant resource to aid permitting authorities in developing case-by-case MACT will be proposed regulations for the subject source categories, or closely related regulations in similar industries. Proposed regulations will contain what EPA believes MACT is at the time of proposal. Although permitting authorities are not required to adopt proposed MACT, and the proposed rule should not be considered a default MACT, it can still serve as a suggestion for what the latest thinking is and would be the result of analysis of the largest body of information.

In addition to the following sources of information, the EPA home page on the World Wide Web includes a wealth of information, including some of the data bases described below. The reader may wish to consult the following websites for additional information:

1. EPA: http://www.epa.gov/epahome/index.html
2. Office of Air and Radiation: http://www.epa.gov/oar/oarhome.html
3. Office of Air Quality Planning and Standards: http://www.epa.gov/oar/oaqps
4. Air Toxics Website: http://www.epa.gov/ttn/atw/

AEROMETRIC INFORMATION RETRIEVAL SYSTEM (AIRS) TOXICS PROGRAM

The AIRS is designed to accommodate the expansion of emissions data. The AIRS/AFS is a National Data System currently residing on the National Computer Center (NCC). The stationary source component of this system replaced the old National Emission Data System (NEDS) as the data repository for point source data (e.g., electric utilities, industrial plants and commercial enterprises). The AIRS/AFS system is expected to eventually provide the capabilities needed to house information from the Title V operating permits program.

Many States input their data directly into the AIRS and perform calculations and retrievals. When a converter (an interface between AIRS and the State system) is used, the data can be input directly to the State system and to the appropriate fields in AIRS in a single step. Data can also be retrieved from AIRS directly, or into the State format using a converter.

Because many data sources are fed into AIRS/AFS, some of this data may be useful for case-by-case MACT determinations and MACT standards. This advantage is expected to become more visible as the search for the 12-percent floor for a source category or subcategory becomes a common occurrence.

INFORMATION COLLECTION REQUESTS (ICR) DATA

For the national MACT standards program, the EPA is currently involved in data collection activities for many of the source categories on the list. These data collection activities are designed to help answer, for a given category, a number of important questions:

- What are the sources of emissions for the category?
- Which HAPs are emitted and at what rates?
- What alternatives are available to reduce those emissions?
- What costs would be imposed for the control alternatives, and what economic impacts would the alternatives have on the business climate for the industry?
- Which alternatives meet or exceed the "MACT floor" (for new sources, the "best controlled similar source;" for existing sources, the level achievable by the "average of the best performing 12 percent" of sources in the category)?
- Given the alternatives available, which alternative represents the "maximum degree of reduction achievable," taking into account costs, benefits, and the constraints imposed by the "MACT floor?"

RACT/BACT/LAER CLEARINGHOUSE (RBLC)

The RBLC maintains a database consisting of 3,600 (and growing) Reasonably Available Control Technology (RACT), Best Available Control Technology (BACT), and Lowest Achievable Emission Rate (LAER) determinations made by State and local agencies for specific sources, as required by the Act. The RACT determinations address emission requirements for existing sources located in nonattainment areas. The BACT and LAER address emission requirements for major new or modified sources located in attainment and nonattainment areas, respectively. Database parameters include: facility information; process description; pollutant information (including emission limit); pollution prevention and/or control technology method; compliance verification information; and cost information (if it exists). The Act requires agencies to submit LAER determinations to the RBLC. The RACT and BACT determinations are submitted on a voluntary basis.

The RBLC also maintains a regulation database that summarizes Federal new source performance standards (NSPS), national emission standards for hazardous air pollutants (NESHAP), and maximum achievable control technology (MACT) standards. The regulation database parameters are similar to those in the RACT/BACT/LAER database, but also include Federal Register and regulation background documentation information.

The RBLC can be accessed through the Office of Air Quality Planning and Standards (OAQPS) Technology Transfer Network (TTN) electronic bulletin board system. For more information, access the RBLC on the TTN or contact the EPA Information Transfer Group at (919) 541-5547.

GREAT WATERS PROGRAM

In order to provide information needed for decision making, the Great Waters program is evaluating HAPs emission data, especially for the Great Lakes region. (Section 112(c)(6) requires national emission inventories for alkylated lead; polycyclic organic matter; hexachlorobenzene; mercury; PCBs; 2,3,7,8-tetrachlorodibenzofurans; and 2,3,7,8-tetrachlorodibenzo-p-dioxin.) Periodic reports to Congress are required to provide information on: relative pollutant loading contributed to aquatic ecosystems from the atmosphere; adverse effects of that loading on human health and the environment; whether the atmospheric deposition causes or contributes to violations of water quality standards or criteria; and sources of the atmospherically deposited pollutants. The goal of the program is to determine if additional regulation is warranted, and if so, what it should entail. For additional information on the Great Waters Program, or for referral to related emission inventory efforts, call the EPA Visibility and Ecosystem Protection Group at 919-541-5531.

AIR TOXIC EMISSION FACTORS

Emission factors are used in lieu of emission estimates based upon source testing, and they can be used to estimate the emissions of a particular HAP per unit process rate (i.e., pounds of nickel emitted for each ton of nickel ore processed). These emission factors can be based on controlled and uncontrolled processes, and can, therefore, be used to help determine which control measures are best suited to a particular process. The EPA has developed screening methods for the development of air toxics emission factors, and applies the screening methods to test results as they become available for use.

The toxic emission factors available through the Factor Information Retrieval System (FIRE) and the EPA document, Compilation of Air Pollution Emission Factors (AP-42) are rated A (most reliable, based on several tests meeting high confidence criteria) through E (least reliable, having limited available information). Toxic emission factors are being developed for about 170 the 189 HAPs on the Section 112(b) list, representing many (but not all) processes in Section 112 source categories.

About 40 of the HAPs in FIRE have been targeted as "critical" pollutants because they are found in a wide variety of industries, and/or are especially toxic. Many of the emission factors for this critical group have a rating of A or B, enabling users to arrive at the most accurate emissions estimates presently possible. For more information on FIRE, contact INFOCHIEF at 919-541-5285.

STATE AIR OFFICE DATABASES

Emission Standards Division (ESD) staff have worked with STAPPA/ALAPCO to better characterize the toxics information available in database form and hard copy within the State air offices.

Most States have compiled pollutant information in some form in response to State Implementation Plan (SIP) requirements. Many States also have toxics information collection systems, as well as State requirements for toxics programs. Most States find that although internally their system is widely used (intra-State system), to down load or upload data on an inter-State basis is nearly impossible (with the primary exception to this being States within a transport region, and then usually under limited circumstances).

TRADE JOURNALS AND VENDOR INFORMATION

Caution should be taken when employing information in trade journals and from vendors, especially in noting the method of emissions estimation, number of tests that were used in developing estimates, and the conditions under which tests were conducted. Other factors that may affect the emissions estimates should also be identified, and the effects of their differences quantified as accurately as possible. Because results applicable to only one or a small group of facilities cannot be completely accurate for other facilities, this source of information is not regarded as highly accurate, but may provide some useful information on control alternatives.

Other sources of information that may be consulted in making MACT floor determinations are listed below. This list is not inclusive, but may provide useful information.

Air Pollution Training Institute (APTI). December 1983. Overview of PSD Regulations. EPA 450/2-82-008.

Air Pollution Training Institute (APTI). June 1983. Air Pollution Control Systems for Selected Industries. EPA 450/2-82-006.

Environmental Protection Agency (EPA). May 1992. Facility Pollution Prevention Guide. EPA 600/R-92/088.

Environmental Protection Agency (EPA). February 1992. Documentation for Developing the Initial Source category or subcategory List. EPA 450/3-91-030.

Environmental Protection Agency (EPA). June 1991. Hazardous Waste TSDF - Background Information for Proposed RCRA Air Emission Standards. EPA 450/3-89-023 (a) and (c).

Environmental Protection Agency (EPA). October, 1990. New Source Review Workshop Manual. EPA, Research Triangle Park, NC (Draft Document).

Environmental Protection Agency (EPA), January 1990. OAQPS Control Cost Manual. EPA 450/3-90-006.

Environmental Protection Agency (EPA). June 1991. Control Technologies for Hazardous Air Pollutants. EPA 625/6-91/014.

Air & Waste Management Association. 1992. Air Pollution Engineering Manual. Van Norstrand Reinhold.

Appendix A

Examples of MACT Analyses

The following detailed examples presented in this manual are for illustrative purposes only. Numbers and values presented in this Appendix do not necessarily reflect any known cases and are not meant to establish any official EPA position regarding MACT determinations for a particular MACT-affected source. These examples are hypothetical and are designed to highlight many of the subtle aspects of the MACT determination process. In many cases, the scenarios and available control technologies have been grossly oversimplified to streamline the presentation of the examples.

The following examples are presented in this Appendix:

Example 1 - Determining the MACT Emission Unit

Example 2 - Using Control Efficiency Ratings to Determine the MACT Floor

Example 3 - When the MACT Floor is Determined Using Emission Reduction Ratios

Example 4 - When the MACT Floor is Equal to "No Control"

Example 1

Determining the MACT Emission Unit

This example illustrates possible grouping mechanisms and rationale for developing one or more MACT emission units at a given facility subject to a MACT determination under Section 112(j).

Description of Source

In this example, a metal furniture manufacturer produces military-specification office furniture for use in military barracks. The plant currently operates 2,080 hr/yr and produces 12,000 units of furniture annually. The facility is considered a major source of HAP emissions.

Existing unit operations include:

1) Wood Processing

Raw wood and formica are glued together to form a laminate. The glue is applied using an automatic application system. Several laminates are then positioned in a press for glue curing. Next, the boards undergo various woodworking operations including, cutting, drilling, and routing. Boards are either transferred to assembly or directly packaged and shipped. Tetrachloroethylene is a component of the glue. Glue stations are vented to emission stacks on the ceiling. The stacks are currently uncontrolled.

The glue is stored in 50 gallon drums. Glue is transferred to the application equipment through a pumping mechanism. Estimated yearly emissions of HAP from this operation is 0.50 tpy.

2) Metal Processing

Metal stock is cleaned by immersion in a toluene dip tank. A toluene, grease, and dirt sludge is produced, which is pumped from the bottom of the tank for disposal. After cleaning, the metal undergoes various metalworking operations including cutting, punching, folding, and welding. Pieces are partially assembled, then transferred to one of two paint coating operations. The dip tank is currently controlled with a condensing unit and a freeboard ratio of 0.75. Yearly controlled emissions are estimated at 19 tons/yr. Uncontrolled emissions are estimated at 55 tpy.

3) Cleaning Operations

The spray coating operations begin with a five-stage cleaning process. The first stage is an alkaline-wash tank. Next, parts are sprayed with an iron phosphate solution. The fourth stage is a rinse tank. Finally, parts are sprayed with a rust preventive. After cleaning, the parts are conveyed to a dry-off oven and then to the paint coating line. No HAP emissions occur during this part of the operation.

4) Painting Operations

There are currently four spray booths in the paint coating operation and one coating dip-tank. Large metal parts are coated using the spray booths. A one-color coating is applied at a coating depth of 1 ml. Two of the booths are equipped with continuously recirculating water curtains to entrap paint overspray. Entrapped paint solids and wastewater are dumped to a holding tank periodically. Air filters are used in the two remaining spray booths. The air filters are periodically replaced. The used filters are placed in storage drums for later disposal.

All spray booths are equipped with hand-held spray guns. Transfer efficiency is estimated at 45 percent for both types of booths. The paint is a high solvent paint containing xylene and toluene with an estimated 35-percent solids content and 65-percent solvent content. The spray guns are periodically sparged and rinsed with acetone to prevent clogging. The acetone paint mixture is sent to storage tanks for later disposal. Emissions from the booths are currently vented to the roof with no control device.

After painting, parts are conveyed through a flash-off area to one of two dry-off ovens and then to assembly. Small metal parts are dip-painted in the coating dip-tank, allowed to air dry, and then transferred to the assembly area.

Total annual HAP emissions from this area are estimated at 55 tpy. Each spray booth contributes 8 tpy and each drying oven 4 tpy. Estimated emissions from the coating dip-tank are 15 tpy. No emission estimates are available for the flash-off area.

From this description, the following emission points are identified as potentially "affected emission points" by the Section 112(j) MACT determination process:

- Glue storage drums
- Glue stations (stack emissions)
  - --Application equipment
  - --Curing presses
- Toluene dip tank*
- Toluene storage tanks*
- Toluene/sludge waste storage tanks*
- Spray booths (stack emissions)
  - -- Feed and waste lines
  - -- Application equipment
- Coating dip-tank
- Flash-off area (large parts)
- Drying area (small parts)
- Paint storage tanks
- Solvent storage vessels
- Paint sludge storage tanks
- Drying ovens (stack emissions)
- Air filter storage drums

* These units would be eliminated from any MACT emission unit because the emission points would be part of the degreasing source category or subcategory, not the miscellaneous metal parts surface coating source category or subcategory.

Possible MACT emission unit scenarios:

Scenario #1: Five MACT emission units:

- Wood processing
- Spray coating operations

- Storage tanks
- Storage drums
- Equipment leaks

This scenario could make sense if a MACT floor could be identified or control technologies could be applied to the emission units. In wood processing, the emissions are vented to a stack on the roof. These emissions could be controlled with a variety of add-on control devices. The source could also consider switching to a glue that has a lower concentration of a HAP or does not contain any HAPs.

In the spray operations, the source could switch to a low-solvent paint or water-based paint. This control option would need to be weighed against controlling the individual emission points. Other control options to consider would be an add-on control device to control the stack emissions from the spray booth and oven, increasing the transfer efficiency of the spray application equipment, and controlling the drying, flash-off areas, and the coating dip-tank with separate control technologies.

Controlling the storage tanks as one emission unit may allow flexibility in meeting MACT. Some tanks could remain under controlled while others could be over-controlled. This option would need to be weighed against the cost effectiveness and emission reductions of applying controls to all of the storage tanks. The storage drums could be placed in a contained area and the emissions vented to one control device.

Equipment leaks are not suitable for combination with other emission units because they are only controllable using work practice and other unquantifiable emissions reductions procedures.

Scenario #2: Four MACT-affected emission units:

- Stack emissions (spray booths, glue stations, drying ovens)
- Storage tanks and drums
- Coating dip-tank
- Equipment leaks

In this scenario, the stack emissions from the spray booths, glue stations and drying oven could all be vented to a single control device. This option would need to be weighed against the emission reductions that could be obtained by applying pollution prevention strategies to the individual operations. If the storage tanks and drums are stored in a common location, such that the emissions from the area could be vented to a control device, this emission point aggregation could make sense. The emission reduction would need to be weighed against controlling the emission points separately. If greater emission reductions could be obtained by controlling these points separately, this aggregation of points may not be acceptable.

Scenario #3: Seven MACT emission units:

- Each storage tank
- Each spray booth

- Stack emissions from glue stations and drying ovens
- Equipment leaks
- Each storage tank
- Each storage drum
- Coating dip-tank

If detailed data are available for each of these individual emissions units, then one approach would be to compile that data and develop a MACT floor data base for each type of emission unit. This scenario would generally be acceptable unless a pollution prevention method could be applied to one of the processes that could obtain a greater degree of emission reductions then point-by-point compliance.

Scenario #4: All emission points.

This scenario would generally be unacceptable because, as described in Scenario #1, equipment leak emissions should not be included in a source category- or subcategory-wide emission unit.

Scenario #5: Two MACT emission units:

- Equipment leaks
- Remaining emission points

This aggregation of emission units could be acceptable if emissions information were available on HAP emissions or control technologies from the source category or subcategory as a whole, or if the nature of the industry demanded a large degree of flexibility in the application of MACT.

Example 2

Using Control Efficiency Ratings to Determine the MACT Floor

Description of Source

In this example, a MACT determination is to be conducted on a quenching process at a coke-by product plant. Hazardous emissions can be released when the hot coke in the quench car is sprayed with water to decrease the coke's temperature. Phenol and naphthalene emissions can occur in the gaseous state. Other pollutants can sorb to particulate matter and be collectively released. The permitting authority will need to conduct a MACT analysis to determine the MACT emission limitation based on the emission reduction that can be achieved by MACT. The permitting authority will begin with the Tier I analysis.

Step 1: Identify the MACT emission unit(s)

MACT unit: quenching tower and coke car # of existing sources: 36

The equipment used in this production process includes the quenching tower, coke car, water delivery system, and water storage system. The permitting authority decides that emission points from the quenching tower and coke car should be considered one MACT emission unit, and the water delivery system and water storage system as another MACT emission unit. The example will be continued for only the quench tower/coke car emission unit.

Step 2: Make a MACT Floor Finding

	Technology	# of plants using	Emission control efficiency, %
1)	Use clean water to quench coke with baffles at the top of the quench tower	10	not quantifiable
2)	Use covered quenched car. Cool outside of car. Water does not impact coke. Place car on cooling rack after quenching for additional heat dissipation	1	almost 100%
3)	Wet scrubber, connected to fixed duct system	10	80-90%
4)	Wet scrubber, mobile unit attached to coke quench car	14	80-90%
5)	Dry quenching with inert gases. Heat transported to waste-heat boiler	1	99-100%

The permitting authority decides to use the control efficiency ratings to determine the MACT floor. There are a total of 36 existing sources. The MACT floor would be equivalent to the arithmetic mean of the control efficiency ratings for the best five sources. If a specific control efficiency rating is not available for the best performing five sources, a median or mode could be used to calculate the MACT floor. Using the information provided, the median of the best performing 12 percent of sources would be equal to 80-90 percent or control technology 3 or 4. The mode would be technology number 4.

Step 3: Identify MACT

Technologies 2, 3, 4, or 5 could be chosen as MACT. Technology 1 could also be considered because its control efficiency is not quantifiable. If technology 1 is to be considered further, a more detailed analysis would be required to prove that the technology could obtain an equal or greater amount of emission reductions. In this case, the efficiency of technology 1 will vary by the concentration of hazardous constituents. Using clean water could result in a less toxic release when the concentration of toxins in the hot coke are less, but increased emissions could result with increased concentrations. The other proposed technologies would operate at a relatively constant efficiency rate, regardless of the pollutant concentration. Therefore, technology 1 would be considered inferior to the other technologies and should be eliminated as a potential candidate.

The permitting authority should identify MACT based on the control technology that achieves a maximum degree of emission reduction with consideration of the costs, non-air quality health and environmental impacts and energy requirements associated with use of each control technology. After identifying MACT, the permitting authority would proceed to Tier III of the analysis.

Example 3

When the MACT floor is Determined Using Emission Reduction Ratios

Description of Source

A surface coating operation treats a product with its existing equipment consisting of a dip-tank priming stage followed by a two-step spray application and bake-on enamel finish coat. The product is a specialized electronics component (resistor) with strict resistance property specifications that restrict the types of coatings that may be employed.

Step 1: Identify the MACT emission unit(s)

MACT emission units:

- Dip-tank
- Feed and waste lines in prime coating operation
- Spray coat booth, spray coat application equipment
- Drying oven
- Storage tank in prime coating operation
- Storage tank in finish coating line
- Paint supply system

There are two process units within this source category or subcategory: the prime coating line and the finish coating line. Equipment within the prime coating line that have affected emission points are a dip-tank, storage containers, feed line to supply new coating into the dip-tank, and a waste line to drain the dip-tank. Because the feed line and waste lines have equipment leak emissions, these emission points should be combined to form a MACT emission unit. The permitting authority will consider the dip-tank and each storage container a separate affected emission unit. Therefore, the three MACT emission units in this process unit are the dip-tank, the storage container, and the feed and waste lines.

The finish coating line consists of two spray booths, spray application equipment, paint supply system, a storage container, and a drying oven. The permitting authority decides to combine affected emission points to form the following MACT emission units: the spray application equipment and spray booths; the paint supply system, the storage container, and the drying oven. For simplicity of this example, the MACT analysis will be continued for only the spray application equipment and spray booths.

Step 2: Make a MACT floor finding

Parts A and B: Compute the Uncontrolled Emissions and Controlled Emissions

Table 1 presents an overview analysis of emissions information for similar emission units within the source category or subcategory.[*]

Table 1.

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[*] The permitting authority should consider whether the process constraints resulting from production specification or other requirements (see Step 3) warrant subcategorization within the category for the purpose of MACT determinations. For the purpose of this example, it is assumed that there will be no subcategorization.

TECHNOLOGY	# OF SOURCES USING
1) Water-based coat	2
2) Low-VOC solvent/high solids coat	4
3) Electrostatic spray application to enhance transfer efficiency	7
4) Low-VOC solvent/high solids coating with electrostatic spray application	8
5) Powder coat paint with electrostatic spray application	1
6) High-VOC solvent coating	7
Total:	29

Table 2 presents the detailed analysis of emission information in this example.

Table 2.

SOURCE	TECHNOLOGY #	UNCONTROLLED EMISSIONS (TONS/YR)	CONTROLLED EMISSIONS (TONS/YR)	EMISSION REDUCTION RATIO
1	6	10	10	0
2	3	26	14	.46
3	2	48	22	.54
4	3	86	56	.35
5	3	98	55	.44
6	6	26	22	.15
7	6	35	34	.03
8	3	78	55	.29

9	2	69	25	.64
10	2	15	11	.27
11	6	11	11	0
12	6	12	12	0
13	6	23	22	.04
14	3	85	52	.39
15	2	141	89	.39
16	3	25	20	.20
17	4	159	100	.37
18	5	126	11	.91
19	4	35	14	.6
20	3	25	16	.36
21	4	68	22	.70
22	4	46	10	.78
23	1	95	10	.89
24	6	96	16	.83
25	4	64	25	.61
26	4	98	31	.68
27	4	168	45	.73
28	4	196	63	.68
	1	255	26	.90

Table 3 presents the top 5 ranked sources.

Table 3.

SOURCE	TECHNOLOGY #	UNCONTROLLED EMISSIONS (TONS/YR)	CONTROLLED EMISSIONS (TONS/YR)	EMISSION REDUCTION RATIO
18	5	126	11	.91
29	1	255	26	.90
23	1	95	10	.89
24	6	96	16	.83
22	4	46	10	.88

	Average of Top 5	618	73	.88

Part C: Compute the Emission Reduction Ratio for the MACT Emission Unit

One option is to calculate the MACT floor based on the average of the emission reduction ratio achieved by the top 5 existing emission units. The top 5 sources are used for this calculation because there are less than 30 sources in the source category. In this case, the MACT floor would be equal to the arithmetic mean of the emission reductions obtained by the top 5 sources in the source category or subcategory, or an 88 percent emission reduction ratio [1 - (sum of controlled emissions ÷ sum of uncontrolled emissions)] or the emission reductions that can be achieved when control technologies 1, 4, or 5 are used at the top-ranked sources.

Part D: Determine a MACT emission limitation (MEL)

Calculate an uncontrolled emission rate (UCEL) for the MACT emission unit based on the normal operation of the emission unit. Emission reductions obtained through a pollution prevention strategy would not be included in the UCEL calculation. The permitting authority calculates the UCEL for this emission unit to be 125 tons/yr total HAPs. Based on this UCEL, The MEL for this emission unit would be

$$\text{MEL} = 125 \text{ tons/yr} * (1 - 0.88)$$

= 15 tons/yr

The permitting authority would advise the permit applicant of the MEL and allow the applicant to determine how this level of emission reductions will be achieved.

Step 3: Select a control technology to meet the MACT Emission Limitation

In this example, the nature of the product requires a specific type of coating, and the applicant is unable to use any of the reviewed technologies to meet the MEL. The owner and operator will analyze other control technologies that are applied to control similar emission points. In this example, the similar emission points have operational losses. Review of control technologies to control operational losses identifies add-on control devices such as a carbon absorber, a thermal or catalytic incinerator, or a condenser. The owner or operator should conduct a cost, non-air quality health and environmental impacts and energy requirements analysis on the available control technologies.

The major source already has a catalytic incinerator on site. The emissions from the spray application equipment and spray booth could be channeled to the incinerator. This would require the installation of a venting system including a pump mechanism. It would also require an increased volumetric flow rate to the incinerator and increase auxiliary fuel requirements. The incinerator had been operating at a 90-percent efficiency. With an increased volumetric flow rate, the efficiency is projected to drop to 87-percent efficiency. The owner and operator must obtain an additional 1-percent emission reductions. Possible control technologies include increasing the operating temperature of the incinerator, or adding electrostatic application to the spray process to enhance transfer efficiency. Limiting the hours of operation at the MACT emission unit could be considered if the reduced production were part of an overall source reduction program.

Use of the specialized coating in this operation will increase the concentration of hazardous pollutants in the water used for the water curtain. The proposed control technology does not affect the concentration of pollutants in the wastewater. This could be considered a negative environmental impact and may be reason to consider another control technology to meet the MACT emission limitation. In this instance, the owner or operator will not violate the NPDES permit, so the control technology will not be eliminated from consideration.

The owner or operator uses this step to demonstrate that despite the increase in volumetric flow rate and the auxiliary fuel requirement, a significant increase in CO_2 emissions does not occur. The owner or operator concludes that the impacts associated with use of this technology are reasonable.

After reviewing the technologies the owner or operator selects the incinerator with a limit on the hours of operation. The owner or operator proposes to start a training program for spray booth operators to decrease the error and product rejection rate. By doing this, the owner or operator can reduce the hours of operation and still meet customer demands for the product. This option is chosen over the other two because increasing the incinerator's operating temperature would require additional auxiliary fuel input, and enhancing the transfer efficiency with electrostatic application would be cost prohibitive. The owner or operator would document that use of the selected control technologies can reduce emissions to the required level.

Example 4

When the MACT floor is Equal to "No Control"

Description of Source

A commercial treatment storage and disposal facility receives off-site wastes from various pesticide manufacturers. A solvent/aqueous/pesticide mixed waste is passed through a distillation column where the organic solvents are vaporized and then condensed into a distillate receiver. The solvent is transferred using tank cars to a tank farm that is located at another portion of the plant. The low-grade solvent is then sold to industrial users. The pesticide-laden wastewater is then passed through a series of carbon adsorbers where the majority of pesticide is removed from the water. The water is then discharged to a Publically Owned Treatment Works (POTW). The carbon adsorbers are periodically steam stripped to regenerate the carbon.

Tier I - Step 1: Identify the MACT emission unit(s)

MACT emission units:

- Each storage tank
- Distillation column, condenser, and distillate receiver
- Three carbon absorbers
- Pumps, feed lines and transfer lines
- Loading racks

The two process units that contain emission points affected by this modification are the recycling process and the tank farm.

The equipment and apparatus associated with the affected emission points are pumps, feed lines, a distillation column, a condenser, a distillate receiving tank, three carbon absorber and transfer lines, and a loading rack. The permitting authority will consider the three carbon absorbers and the associated emission points as one emission unit because a single control technology could be practically designed to cover all three affected emission points. The permitting authority will also group the distillation column, distillate receiver and condenser into one MACT emission unit. The feed lines, pumps, and transfer lines would have equipment leak emission losses and would be another affected emission unit. The permitting authority decides to consider the emission points and equipment for the loading rack and tanks as separate MACT emission units. If all the tanks were structurally similar in design one determination could be made that would be applicable to all the tanks.

Step 2: Make a MACT floor finding

For simplicity of this example, the MACT analysis will only be continued for a tank emission unit. All the storage tanks will be structurally similar, so only one MACT determination will be required. The permitting authority reviews existing data bases and determines that less than 12 percent of tanks in the source category or subcategory are controlled. Therefore the

MACT floor is equal to "no control". This is not automatically an acceptable "control" measure, therefore Tier II of the MACT analysis must be completed. In Tier II of the analysis control technologies for similar emission points from outside the source category or subcategory will also be considered.

Tier II - Step 1: List all available control technologies

The following technologies have been identified as possible control technologies that can be applied to a storage tank to control working and breathing emission losses:

	Technology	Emission control efficiency, %
1)	Fixed-roof	93
2)	Fixed-roof plus internal floating roof	96
3)	Pressure tank	96
4)	Fixed-roof vented to a carbon canister	98
5)	Fixed-roof vented to a combustion device	99
6)	Fixed-roof vented to a carbon absorber	100

Step 2: Eliminate technically infeasible control technologies

All of the available control technologies are technically feasible.

Step 3: Conduct a non-air quality health, environmental, economic and energy impacts analysis

The following series of tables illustrate a non-air quality health, environmental, cost and energy impacts analysis for each control option.

Table 1 presents information describing the secondary air impacts and other resource demands of the various control technologies that are technically feasible.

Table 2 presents the control options along with their costs and emission reductions. The average cost effectiveness of each control option is also presented. The average cost effectiveness is the ratio of the total annual cost to the total amount of HAP removed compared to the baseline. Note that the control options are presented in terms of increasing emission reductions (i.e.,

Table 1.

CONTROL OPTION	SECONDARY AIR IMPACTS	RESOURCE DEMANDS
1) Fixed roof	None	None
2) Fixed roof + internal roof	None	None
3) Pressure tank	None	None
4) Cover and vented to carbon canister	Emissions if carbon regenerated	Disposal of container, solvents for regeneration
5) Cover and vent to combustion device	Increased CO, NOx, SOx, and particulate emissions	Fuel source, disposal of ash
6) Cover and vent to carbon absorber	Emissions when carbon regenerated	Disposal of spent carbon, solvents for regeneration

Table 2.

CONTROL OPTION	CONTROL EFFICIENCY	ANNUAL COST ($)	EMISSION REDUCTION (Mg/Yr)	AVERAGE COST EFFECTIVENESS ($/Mg)[a]
1	93	85,000	72	1,181
2	96	113,000	88	1,284
3	96	232,000	88	2,636
4	98	110,000	92	1,196
5	99	136,000	103	1,320
6	100	189,000	117	1,615

[a] Average cost effectiveness is the annual cost of each control option divided by the annual emission reduction of that option (e.g., $85,000/yr ÷ 72 Mg/yr = $1,181/Mg).

control option 1 has the smallest emission reduction, control option 2 has the second smallest emission reduction, etc.)

Using Table 2, several control options can be eliminated from further consideration. Control option 3 should be eliminated because control option 2 achieves the same amount of HAP reductions, but at a lower cost. Control option 2 should be eliminated because control option 4 achieves a greater degree of emission reduction for lower cost. The elimination of control options 2 and 3 reduces the number of technically feasible and economically efficient options to four control technologies.

Table 3 presents the incremental cost effectiveness of the remaining options. The incremental cost effectiveness of control option 1 is the same as its average cost effectiveness, because control option 1 is the first incremental option from the baseline. The incremental cost effectiveness of control option 4 is the ratio of the difference in cost between options 1 and 4 to the difference in HAP emission reductions between the two ratios.

Table 3.

CONTROL OPTION	**ANNUAL COST ($)**	**EMISSION REDUCTION (Mg/Yr)**	**AVERAGE COST EFFECTIVENESS ($/Mg)**[a]	**INCREMENTAL COST EFFECTIVE-NESS ($/Mg)**[b]
1	85,000	72	1,181	1,181
4	110,000	92	1,196	1,250
5	136,000	103	1,320	2,364
6	189,000	117	1,615	3,786

[a] Average cost effectiveness calculated as described in Table 2.

[b] Incremental cost effectiveness is the difference in the annual cost between two options divided by the difference in emission reductions between the same options (e.g., ($110,000/yr - $85,000/yr) ÷ (92 Mg/yr - 72 Mg/yr) = $1,250/Mg).

Tier III - Step 1: Identify MACT

Examination of the cost effectiveness of the remaining control options can lead to the elimination of other control options.[**] Control option 6 is eliminated because the incremental cost is deemed too high. The incremental cost of control option 5 is deemed acceptable, but, upon closer examination, the secondary air and energy impacts make this

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[**] "Decisions" based on the cost-effectiveness values provided in this example are for illustrative purposes only. In real life situations, cost effectiveness would be evaluated on a case-by-case basis, and the results of one case would not determine absolute bounds on the circumstances under which one would select a level of emission reduction beyond the floor.

option undesirable. The incremental cost of both options 1 and 4 are deemed acceptable; however, control option 1 is eliminated because other considerations (secondary air impacts, etc) do not preclude the selection of control option 4 which achieves a greater degree of emission reductions.

Appendix B

Federal Register Notice on Determining an Average Emission Limitation for Existing Sources, June 6, 1994 (59 FR 29196).

[Federal Register: June 6, 1994]

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[AD-FRL-4892-5]

National Emission Standards for Hazardous Air Pollutants for Source Category: Organic Hazardous Air Pollutants From the Synthetic Organic Chemical Manufacturing Industry and Other Processes Subject to the Negotiated Regulation for Equipment Leaks; Determination of MACT ``Floor''

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: On December 31, 1992, the EPA proposed standards to regulate the emissions of certain organic hazardous air pollutants from synthetic organic chemical manufacturing industry (SOCMI) production processes and seven other processes which are part of major sources under section 112 of the Clean Air Act as amended in 1990 (the Act). This rulemaking is commonly called the Hazardous Organic NESHAP or the HON. In the final action regarding the December 31, 1992 proposal, which was signed on February 28, 1994, and published in the Federal Register on April 22, 1994, EPA deferred taking final action regarding provisions applicable to medium storage vessels due to the need to resolve an issue of statutory interpretation of section 112(d)(3)(A) of the Act. On March 9, 1994, EPA reopened the comment period to request additional comment on the appropriate interpretation of this statutory provision and the effect of that interpretation on the appropriate control requirements for medium storage vessels at facilities subject to the HON.

This action announces EPA's final decision regarding the interpretation of Clean Air Act section 112(d)(3)(A) for purposes of the HON and the final decision regarding control provisions applicable to medium storage vessels in SOCMI facilities subject to the HON. The decision announced in this action regarding the interpretation of Clean Air Act section 112(d)(3)(A) for purposes of the HON will be presumptively followed in subsequent MACT rulemakings, but it will not be binding. Although EPA believes that Congress intended one interpretation--referred to as the ``Higher Floor Interpretation''--in Clean Air Act section 112(d)(3)(A), EPA also believes that the Agency retains discretion in important respects in setting Floors for MACT standards. EPA intends to exercise its discretion, within the statutory framework, to promulgate MACT standards that best serve the public interest.

EFFECTIVE DATE: June 6, 1994.
See Supplementary Information section concerning judicial review.

ADDRESSES: Dockets. The following dockets contain supporting information used in developing the proposed provisions. Docket Number A-90-19 contains general information used to characterize emissions and control costs for the industry and Docket A-90-21 contains information on storage vessels. These dockets are available for public inspection and copying between 8 a.m. and 4 p.m., Monday through Friday, at the EPA's Air and Radiation Docket and Information Center, Waterside Mall, room M1500, 401 M Street SW., Washington, DC 20460. A reasonable fee may be charged for copying.

FOR FURTHER INFORMATION CONTACT: On technical issues, Dr. Janet S. Meyer, Standards Development Branch, Emission Standards Division (MD- 13), U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina 27711, telephone number (919) 541-5254. For further information on the legal issue addressed in this notice, contact Michael S. Winer, Assistant General Counsel, Air and Radiation Division (2344), Office of General Counsel, Environmental Protection Agency, 401 M Street SW., Washington, DC 20460, telephone number (202) 260-7606.

SUPPLEMENTARY INFORMATION:

Judicial Review

Under section 307(b)(1) of the Clean Air Act (CAA), judicial review of the actions taken by this document is available only on the filing of a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit within 60 days of today's publication of this rule. Under section 307(b)(2) of the CAA, the requirements that are subject to today's document may not be challenged later in civil or criminal proceedings brought by EPA to enforce these requirements.

Public Comment: Approximately 55 comment letters were received in response to the March 9, 1994 (59 FR 11018) reopening of the comment period. The majority of these letters were from industries or industrial trade associations, arguing in favor of the less stringent ``Lower Floor Interpretation.'' Environmental groups, State or local governments and labor unions argued almost uniformly in favor of the more stringent ``Higher Floor Interpretation.'' The EPA considered all public comments in framing the final policy for MACT floor determination and in selection of the requirements for medium storage vessels. The major issues raised by the comments are addressed in this preamble. The EPA's responses to all the comments can be found in docket A-90-19, Subcategory VI-B.

I. Summary of Decision on MACT Floor Determination

This section describes EPA's decision with respect to the interpretation of Clean Air Act section 112(d)(3)(A) for purposes of this rulemaking. As set forth in more detail below, EPA believes that one of the interpretations of section 112(d)(3)(A)--referred to as the ``Higher Floor Interpretation''--is the better and more natural reading of the statutory language.

A. Background

Section 112(d)(3) of the Clean Air Act provides that Emissions standards promulgated under this subsection for existing sources * * * shall not be less stringent * * * than--

(A) The average emission limitation achieved by the best performing 12 percent of existing sources * * * 42 U.S.C. section 7412(d)(3). Existing sources for which the Administrator lacks emissions information and those that have recently achieved LAER are excluded from consideration. Id. (For categories or subcategories with fewer than 30 sources, standards may not be less stringent than ``the average emission limitation achieved by the best performing 5 sources.'' CAA section 112(d)(3)(B)). The minimum level of stringency defined by this language has come to be known as the MACT Floor.

In the March 9, 1994 Federal Register, EPA published a notice soliciting comment on ``the appropriate interpretation of'' section 112(d)(3)(A). Two interpretations of section 112(d)(3)(A) were discussed. Under the first, referred to as the ``Higher Floor Interpretation,'' EPA would look at emission limitations achieved by each of the best performing 12 percent of existing sources, and average those limitations. ``Average'' would be interpreted to mean a measure of central tendency such as the arithmetic mean or median. (The arithmetic mean of a set of measurements is the sum of the measurements divided by the number of measurements in the set. The median is the value in a set of measurements below and above which there are an equal number of values, when the measurements are arranged in order of magnitude).

Under the second, ``Lower Floor Interpretation,'' EPA would look at the average emission limits achieved by each of the best performing 12 percent of existing sources, and take the lowest. This second interpretation groups the words ``average emission limitation'' into a single phrase, and asks what ``average emission limitation'' (accounting for variability over time, or between different pollutants being emitted from a facility) is ``achieved by'' all members of the best performing 12 percent.

B. EPA's Interpretation of Section 112(d)(3)(A)

The EPA believes that the ``Higher Floor Interpretation'' is a better reading of Clean Air Act section 112(d)(3)(A) than the ``Lower Floor Interpretation.'' This conclusion is based on a review of the statute, legislative history and comments received in response to EPA's March 9 notice. 1. The Statutory Language Section 112(d)(3)(A) requires that standards be no less stringent than ``* * * the average emission limitation achieved by the best performing 12 percent of existing sources * * *''. The EPA believes that the most natural and straightforward reading of this language would have EPA first determine the emission limitations achieved by sources within the best performing 12 percent, and then average those limitations. This is the method described above as the ``Higher Floor Interpretation.''

The EPA believes that if Congress had intended the Lower Floor Interpretation, language other than that actually used in section 112(d)(3)(A) would have been far more natural. For example, Congress could easily have expressed the Lower Floor Interpretation by requiring standards to be no less stringent than ``the emission limitation achieved by all sources within the best performing 12 percent.'' Similarly, Congress could have required standards to be no less stringent than ``the average emission limitation achieved by the worst performing member of the best performing 12 percent,'' or ``the emission limitation (averaged over time to take account of variability in the effectiveness of control) achieved by all sources within the best performing 12 percent.'' Any of such phrases would have been a more natural way to convey the Lower Floor Interpretation than the language Congress chose. However, the actual language of section 112(d)(3)(A) provides, in straightforward fashion, that standards may be no less stringent than the ``average emission limitation achieved by the best performing 12 percent * * *''. To glean the Lower Floor Interpretation from this language is a strain; words and concepts not set forth in the statute must be added or inferred.

The language of section 112(d)(3)(B) makes this point even clearer. That section requires that standards for existing sources in categories or subcategories with fewer than 30 sources be no less stringent than, “The average emission limitation achieved by the best performing 5 sources * * *” 42 U.S.C. 7412(d)(3)(B).

If an interpretation parallel to the Lower Floor Interpretation were intended, it would have been more natural for this provision to read ``the emission limitation achieved by the 5th best performing source.''

2. The Legislative History

The legislative history lends strong support to the view that, in passing section 112(d)(3)(A), Congress intended the Higher Floor Interpretation.

On the House side, the language that would eventually become section 112(d)(3)(A) was offered as a compromise amendment by Rep. Dingell on the House Floor on May 23, 1990. (The language of the amendment was identical to section 112(d)(3)(A) as ultimately enacted into law; only the numbers were different). Rep. Dingell yielded time to Rep. Collins ``for purposes of explaining the amendment.'' Legislative History of 1990 CAA Amendments at 2896. In doing so, Rep. Collins noted that she had originally supported slightly more stringent numbers than those included in the amendment, and that under her original proposal

> The average of emissions from the 10 percent cleanest sources would be the MACT standard. In cases where there are less than 30 sources in a category or subcategory, the average of the 3 cleanest sources would determine the standard.

Id. She went on to explain that under the compromise amendment introduced by Rep. Dingell

> MACT for existing stationary sources would be the average of the best 15 [percent] of technologies within each category or subcategory. For categories or subcategories where there are less than 30 sources, the standard is based on the average emissions from the best performing 5 sources.

Legislative History of 1990 CAA Amendments at 2897.

Rep. Collins' formulations are consistent with the Higher Floor Interpretation, not the Lower. The ``average of the 3 cleanest sources'' cannot mean, as the Lower Floor Interpretation would require, the level of control achieved by all three of the ``cleanest sources.'' Nor can the ``average of the best 15 [percent] of technologies'' mean a technology as good as that used by all sources within the top 15 percent.

Another discussion of section 112(d)(3) is similar. On October 27, 1990, Sen. Durenberger (a principal supporter of the Clean Air Act Amendments) explained the provision on the Senate floor. His explanation was as follows:

> The standard may not be less stringent than the average of the emission levels achieved by the best performing 12 percent of the existing sources within the category* * * The Administrator is to exclude from the calculation of the average of top 12 percent any source which met the following conditions* * *

Legislative History of 1990 CAA Amendments at 870 (Cong. Rec. S16929--Oct. 27, 1990). The second sentence of Sen. Durenberger's statement, in particular, is inconsistent with the Lower Floor Interpretation. Sen. Durenberger makes clear that the ``average'' called for in the statute is of the ``top 12 percent,'' not the emission limitations achieved over time at each individual source.

No legislative history was found that supports the Lower Floor Interpretation. The EPA believes that the legislative history indicates that individual legislators--including those central to the drafting of section 112(d)(3)--understood the word ``average'' to mean that once the emission limitations achieved by the best performers in a category had been determined, those results should be averaged. This is the method of the Higher Floor Interpretation, not the Lower.

3. Issues Raised in Public Comment

a. Arguments Concerning the Statutory Language.

(i) Plain Meaning of the Statute. Several commenters argued that the meaning of the statute was plain on its face and that Congress clearly intended the Higher Floor Interpretation. These commenters argued that when section 112(d)(3)(A) is read as a whole in its most natural way, the Congressional intent in favor of the Higher Floor

Interpretation is clear. They argued that if Congress had intended the Lower Floor Interpretation, it would have used different language in the statute.

The EPA agrees with these comments. As set forth in greater detail above, EPA believes the plain statutory language strongly favors the Higher Floor Interpretation.

(ii) Congress' Failure to Use the Words ``of the''. Several commenters argued that if Congress had meant the Higher Floor Interpretation, it would have added the words ``of the'' to the statute, so that section 112(d)(3)(A) would read ``the average of the emission limitations achieved by the best performing 12 percent.'' These commenters saw the absence of the words ``of the'' in the statute as evidence that Congress intended the Lower Floor Interpretation.

The EPA agrees that the statute would be more clear if Congress had used the words ``of the,'' but disagrees with the conclusion drawn by these commenters for two reasons. First, standard English usage often permits dropping the prepositions ``of the'' without changing the meaning of a phrase. (For example, ``the biggest mountain in North America'' has the same meaning as ``the biggest of the mountains in North America.'' ``Best singer in the band'' has the same meaning as ``best of the singers in the band.'') The same cannot be said, however, for the various phrases and concepts that must be read into section 112(d)(3)(A) in order to arrive at the Lower Floor Interpretation. Phrases like ``the worst performing member of...'' or ``averaged over time...'' simply are not dropped as part of standard English. Their absence from section 112(d)(3)(A)--unlike the absence of the words ``of the''--must be considered significant in interpreting the provision. Second, although the words ``of the'' do not appear in section 112(d)(3)(A), they were used by key legislators in summarizing that section prior to passage of the 1990 Clean Air Act Amendments. As noted above, when Sen. Durenberger (a principal supporter of the Clean Air Act Amendments) spoke on the Senate floor on October 27, 1990, he explained section 112(d)(3)(A) as follows:

> The standard may not be less stringent than the average of the emission levels achieved by the best performing 12 percent of the existing sources within the category* * *

Legislative History of 1990 CAA Amendments at 870 (Cong. Rec. S16929--Oct. 27, 1990) (emphasis added). As also noted above, when Rep. Collins introduced the provision in the House, she described it as follows:

> The average of emissions from the 10 percent cleanest sources would be the MACT standard. In cases where there are less than 30 sources in a category or subcategory, the average of the 3 cleanest sources would determine the standard.

Legislative History of 1990 CAA Amendments at 2896 (emphasis added) (describing a provision with identical language but different numbers than the one ultimately enacted into law).

In EPA's view, the fact that Congress did not use the words ``of the'' in section 112(d)(3)(A) is fully consistent with standard English. However, the fact that key legislators did use these words in describing the provision to their colleagues, in combination with the failure of those legislators to use the phrases on which the Lower Floor Interpretation depends, provides a strong indication that Congress intended the Higher Floor Interpretation in enacting section 112(d)(3)(A).

(iii) Purpose of the Word ``Average''. Several commenters argued that the word ``average'' in section 112(d)(3)(A) should be read to require averaging not of emissions from different sources within the top 12 percent, but instead of emissions from individual sources at different times, or from different emission points, or made up of different HAP. The EPA does not agree that the word ``average'' in section 112(d)(3)(A) can reasonably be read to serve this purpose. First, such a reading is difficult, if not impossible, to reconcile with the provision of section 112(d)(3) establishing a ``floor'' for new sources. Under those provisions, new source standards may not be less stringent than

> The emission control that is achieved in practice by the best controlled similar source.

42 U.S.C. 7412(d)(3). Notably, Congress did not use the word ``average'' in this provision. If the word ``average'' in section 112(d)(3)(A) was intended to refer to averages across time, or between emission points, or among different HAP, then Congress must have intended that such averaging would take place for existing source standards, but not for new source standards. There is no reason to believe Congress intended this implausible result.

There is a much more likely explanation: That to the extent Congress contemplated that averaging across time, or between emission points, or among HAP would play a role in either existing or new source MACT standards, it considered the terms ``emission limitation'' and ``emission control'' fully adequate to reflect that fact. In EPA's air program, emission limitations have routinely been expressed in terms of averages across time, for example, without any special statutory direction or authority. There is no reason to believe that Congress would have thought that special instructions were needed to ensure that EPA continued this practice, and even less reason to believe Congress would have thought special instructions were needed with respect to existing source standards, but not new source standards.

Furthermore, the legislative history of section 112 casts doubt on the interpretation of the word ``average'' offered by these commenters. When Congress comprehensively revised section 112 in the Clean Air Act Amendments of 1990, it based the revisions in substantial part on the Clean Water Act's effluent guidelines program. (See, e.g., Remarks of Sen. Durenberger, Cong. Rec. S516 (January 30, 1990) (``* * * this approach to regulation of toxic air pollutants is not without precedent. A program very similar to the one I have just described has already been implemented under the Clean Water Act'').) Under that program, certain limits (known as ``BPT limits'') have long been based on the ``average of the best'' performance at existing facilities. (See generally Remarks of Sen. Muskie, Legislative History of Federal Water Pollution Control Act of 1972 at 169-70 (``The Administrator should establish the range of `best practicable' levels based upon the average of the best existing performance by plants of various sizes, ages and unit processes.'')) In determining ``average of the best'' under the Clean Water Act, EPA has historically identified the best performers in an industrial category, and then averaged their performances. This methodology is consistent with the Higher Floor Interpretation and not the Lower.

(iv) Proximity of the Word ``Average'' to the Words ``Emission Limitation''. Several commenters argued that the proximity of the word ``average'' to the words ``emission limitation'' suggests that ``average'' modifies ``emission limitation,'' and not the entire phrase following those words. The EPA does not agree with this argument. In English, adjectives often modify not only the noun immediately following, but an entire phrase. In the phrase ``the biggest mountain in North America climbed by members of the Washington, D.C. Climbing Club,'' for example, the adjective ``biggest'' modifies the entire remainder of the phrase. There is no reason to conclude that the word ``average'' in section 112(d)(3)(A) plays a different role.

(v) Use of the Words ``Achieved By''. Several commenters argued that the use of the words ``achieved by'' in the statute indicates that all sources within the top 12 percent must be achieving the emission limitations used to set the MACT Floor.

The EPA does not agree with this argument. The EPA believes the argument depends both on inferring the presence of the word ``all'' in section 112(d)(3)(A), and (as discussed above) on ignoring, or incorrectly construing, the meaning of the word ``average.'' Section 112(d)(3)(A) simply does not say ``the emission limitation achieved by all sources within the best performing 12 percent* * *''. Congress' use of the words ``achieved by'' cannot reasonably be stretched to accomplish such a rewriting of the statute.

b. Arguments Concerning Structure of the Statute. Several commenters argued that elements of the statute's structure support the Lower Floor Interpretation. For example, some commenters argued that the Lower Floor Interpretation best reflects EPA's authority to consider cost and other factors in setting standards more stringent than MACT Floor. Other commenters argued that the Lower Floor Interpretation best reflects the distinction between existing source MACT and new source MACT.

The EPA does not agree with these arguments. In fact, the Higher Floor Interpretation fully preserves both of these structural elements of the statute. With the Higher Floor Interpretation, just as with the Lower, EPA still has authority to establish existing source standards more stringent than the Floor based on enumerated criteria. With the Higher Floor Interpretation, just as with the Lower, there is still a distinction between the Floor for existing sources and the level of control required for new sources. (Under section 112(d)(3), standards for new sources must be at least as stringent as ``the emission control that is achieved in practice by the best controlled similar source''). The fact that there may be ``less distance'' to travel above the Floor with the Higher Floor Interpretation does not establish an inconsistency between that interpretation and other parts of the statute, nor does it mean that the interpretation is flawed in any way.

Furthermore, structural arguments tend to favor the Higher Floor Interpretation more strongly than the Lower. Section 112 was passed in its current form to ensure quick and dramatic reductions in air toxics emissions. Congress was frustrated with the slow pace of toxics control prior to 1990, and many members in part blamed EPA for weak controls. See, e.g., H. Comm. Rep. 101-490 at 150-54, 322-23; S. Rpt. 101-228 at 128-33. The structure and purpose of section 112 as a whole indicates that section 112(d)(3)(A) was intended to establish a stringent minimum level of control for hazardous air pollutants.

c. Additional Arguments. Several commenters argued that the Higher Floor Interpretation would require EPA to set MACT Floors that failed to correspond to real-world control technologies.

The EPA does not agree with this argument. The EPA believes that the argument depends upon a flawed premise: That the word ``average'' can only mean ``arithmetic mean.'' In fact, there are a number of conventional methods for determining the average of a data set, including the median. Congress did not mandate a particular method of determining ``average'' or central tendency in section 112(d)(3)(A), and the choice of methodology--whether median, mean, or some other measure--can often change the results markedly. For example, if the five facilities that make up the top 12 percent of a source category are achieving reductions equal to 99 percent, 98 percent, 95 percent, 94 percent and 93 percent, EPA need not set the MACT Floor equal to the arithmetic mean of these values, which is 95.8 percent. Using the Higher Floor Interpretation, EPA could set the MACT Floor equal the median of these values, which is 95 percent.

This discussion responds to the most significant comments on legal issues received in response to the March 9, 1994 Federal Register document. Other comments on legal issues are addressed in item number VI-B-61 in docket A-90-19.

C. Conclusion

The EPA believes that Congress spoke with clarity in section 112(d)(3)(A) of the Clean Air Act. That provision--requiring standards to be no less stringent than ``the average emission limitation achieved by the best performing 12 percent of existing sources''--lends little support for an interpretation under which standards might be set at the emission limitation achieved by the worst performing member of the best performing 12 percent of existing sources. The legislative history offers no support for such an interpretation, and indeed points strongly in the opposite direction. The EPA believes that the Higher Floor Interpretation represents the best reading of the statutory language.

II. Discretion in Setting Floors for MACT Standards

In today's notice, EPA announces its conclusion that Congress intended the Higher Floor Interpretation. The effect of this decision, however, is not to identify any particular number (e.g. the 94th percentile) as the Floor for all MACT standards. EPA retains discretion in important respects in setting Floors for MACT standards, and intends to exercise its discretion, within the statutory framework, to promulgate MACT standards that best serve the public interest.

EPA believes the Agency retains substantial discretion, within the statutory framework, to set MACT Floors at appropriate levels. For example, because Congress did not define the term ``average'' in section 112(d)(3), or in the legislative history, it implicitly delegated the authority to EPA to do so. The choice of methodology-- whether mean, median, mode, or some other measure--can often change the results. (The mean of a set of measurements is the sum of the measurements divided by the number of measurements in the set. The median is the value in a set of measurements below and above which there are an equal number of values, when the measurements are arranged in order of magnitude. The mode is the value that occurs most often in a set of measurements). As some commenters noted, the ``average of the best performing 12%'' corresponds to the 94th percentile when the word ``average'' is construed to be the ``median.'' If, however, ``average'' is construed to be the ``arithmetic mean'' or ``mode,'' a different result may obtain. EPA construes the word ``average'' in section 112(d)(3) to authorize the Agency to use any reasonable method, in a particular factual context, of determining the central tendency of a data set. In addition, EPA has discretion to use its best engineering judgment in collecting and analyzing the data, and in assessing the data's comprehensiveness, accuracy and variability, in order to determine which sources achieve the best emission reductions. EPA also has discretion in determining how to analyze the data, and thus in determining the appropriate ``average'' in each category or subcategory.

There are other important ways that EPA retains discretion in setting MACT floors. For example, Congress authorized EPA to subcategorize source categories based on classes, types and sizes of sources, which will result in different Floors for different subcategories. CAA section 112(d)(1). Using this authority, EPA can tailor standards to certain characteristics of particular emission units and sources. EPA retains flexibility, for example, to conclude that the production processes used at particular sources in the relevant category are sufficiently different from processes used at other sources in the same category to justify the creation of a new subcategory.

These examples are not meant to be exhaustive. EPA has only begun the process of setting MACT standards. As EPA gains experience in setting MACT Floors, other issues may arise that will require EPA to exercise its discretion in determining, for each case, what represents the average emission limitation achieved by the best performing 12% of existing sources (or the best performing five sources, in categories or subcategories with fewer than 30 sources).

III. Precedential Impact of Today's Determination

In its March 9, 1994 document, EPA stated that ``the MACT floor decision * * * in this rulemaking will have broad precedential effect, and will be presumptively followed in subsequent MACT rulemakings." 59 FR 11018. Several commenters objected this statement, arguing that the issue of how best to interpret section 112(d)(3)(A) should have been addressed in a separate, generally applicable rulemaking.

The EPA wishes to emphasize that, although today's decision concerning the interpretation of Clean Air Act section 112(d)(3) for purposes of the HON will be precedential for future rulemakings, it will not be binding. Specifically, EPA will fully consider all comments on individual MACT standards, including those regarding the proper interpretation of the language in sec. 112(d)(3)(A), received on or before the close of the comment periods for those standards.

IV. Application of MACT Floor Decision to Medium Storage Vessels at Facilities Subject to the HON

As described in the March 9, 1994 Federal Register reopening the comment period, EPA requested comment on whether the control requirements for medium storage vessels previously proposed by EPA would be appropriate in the event those proposed controls were to be determined to be more stringent than the floor. Only four commenters addressed the question of the appropriate controls requirement for medium storage vessels and provided rationale for their opinions. Of these commenters, only one submitted information which purported to represent control information for SOCMI storage vessels. This information was reviewed and found to not provide any information on control performance and to represent storage vessels associated with non-SOCMI processes (i.e., other source categories) as well as SOCMI processes. Therefore, the submitted information could not be used to revise the database. The EPA review of this information is contained in item VI-B-62 in docket A-90-19. This section of the preamble, therefore, only presents the basis for the final decision on control requirements for medium sized storage vessels.

For medium vessels, about 8 percent of the vessels are controlled with either a 90-percent efficient control device or an IFR or EFR with a continuous seal. All of the controlled medium-sized vessels contained liquids with vapor pressures of 13.1 kPa (1.9 psia). Because the arithmetic mean characteristics of the top 12 percent of the medium vessels would not represent the performance of any known technology, the EPA used the median as the average for these vessels. Thus, for medium-sized storage vessels, the floor determined by the average characteristics of the top 12 percent of the sources would require control of vessels storing liquids with vapor pressures of 13.1 kPa (1.9 psia) by either a 90-percent efficient control device or an IFR or EFR with a continuous seal.

In selection of the control provisions for medium-sized storage vessels, EPA considered the regulatory alternatives that were presented in the April 22, 1994 Federal Register document. These alternatives reflected a combination of: (1) The floor control for medium-sized storage vessels, which at the time of proposal, were equipped with the floor controls and (2) the proposed control provisions for medium-sized storage vessels which were equipped with no control or less efficient controls than the performance of the revised floor component for the source-wide floor. The EPA did not develop a regulatory alternative corresponding to application of the revised floor control level to all storage vessels. Such an alternative would have essentially the same control costs as the proposed control provisions, but would result in a lower emission reduction. Because the floor control would represent a less economically efficient option and would add to the complexity of the rule, this option was not formally evaluated.

For medium storage vessels at existing sources, control at the regulatory alternative used to represent the floor control was estimated to cost $2.4 million/yr and to result in an emission reduction of 370 Mg/yr (110 tons/yr). The regulatory option for control level beyond the floor component is estimated to further reduce emissions by less than 100 Mg/yr (110 tons/yr) at an additional cost of $4 million/yr, or $48,000/Mg for each additional Mg of emission reduction. Due to the relatively high incremental costs and low emission reductions of this alternative, the EPA believes that the control level for the medium storage vessels component of the source- wide floor represented the maximum reduction achievable considering cost and other impacts.

IV. Administrative Requirements

A. Docket

The docket is an organized and complete file of all the information submitted to or otherwise considered by EPA in the development of this rulemaking. The principal purposes of the docket are: (1) To allow interested parties to identify and locate documents so that they can effectively participate in the rulemaking process and (2) to serve as the record in case of judicial review (except for interagency review materials) (Section 307(d)(7)(A)).

B. Paperwork Reduction Act

The information collection requirements of these provisions in this rule have been submitted for approval to the OMB under the Paperwork Reduction Act, 44 U.S.C. 3501 et seq. An Information Collection Request document has been prepared by the EPA (ICR No. 1414.02), and a copy may be obtained from Sandy Farmer, Information Policy Branch, EPA, 401 M Street, SW., (2136), Washington, DC 20460, or by calling (202) 260- 2740. These requirements are not effective until OMB approves them and a technical amendment to that effect is published in the Federal Register.

The reporting and recordkeeping burden of the information collection requirements of the provisions for medium sized storage vessels are included in the estimate of the overall reporting burden, which is presented in ICR No. 1414.02. The information collection requirements for the entire rule has an estimated annual reporting burden averaging 1,400 hours per response, and an estimated annual recordkeeping burden averaging 5,400 hours per respondent. These estimates include time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information.

Send comments regarding the burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden, to Chief, Information Policy Branch, EPA, 401 M Street, SW., (Mail code 2136); Washington, DC 20460; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503, marked ``Attention: Desk Officer for EPA."

C. Executive Order 12866

This final action regarding provisions applicable to medium sized storage vessels in facilities subject to the HON has been reviewed in accordance with Executive Order 12866. Under the terms of the Order, the Administrator has assessed the potential costs and benefits of the regulatory action. The methods for and results of these cost and benefit analyses are described in the HON's Regulatory Impact Analysis (RIA). The RIA was included in the HON docket at proposal, and thus it was made available for public comment.

Executive Order 12866 also requires that the record for ``significant'' rules include an assessment of the potentially effective and reasonably feasible alternatives to the planned action. The potentially effective and reasonably feasible alternatives to the control requirements in the HON were also analyzed as part of the rule development process. The methods for and results of these analyses are described in the HON's Background Information Document (BID). The BID was included in the HON docket at proposal, and thus it was also available for public comment. In addition, many of the alternative requirements considered by the Administrator were described in the preamble for the HON proposal.

The potential costs associated with selection of the final provisions are primarily the result of statutory requirements. All elements of the cost that are not directly attributable to statutory requirements were deemed appropriate because the Administrator determined that they were necessary for administering this program effectively and efficiently. In assessing the potential costs and benefits--both quantitative and qualitative--of this rule, the Administrator has determined that the benefits justify the costs.

The Administrator has also determined that this regulatory action does not unduly interfere with State, local and tribal governments in the exercise of their governmental functions.

D. Regulatory Flexibility Act Compliance

The Regulatory Flexibility Act (5 U.S.C. 601 et seq.) requires the EPA to consider potential impacts of Federal regulations on small business entities. If a preliminary analysis indicates that a proposed regulation would have a significant economic impact on 20 percent or more of small entities, then a regulatory flexibility analysis must be prepared.

Regulatory impacts are considered significant if any of the following criteria are met: (1) Compliance increases annual production costs by more than 5 percent, assuming costs are passed on to consumers; (2) compliance costs as a percentage of sales for small entities are at least 10 percent more than compliance costs as a percentage of sales for large entities; (3) capital costs of compliance represent a ``significant'' portion of capital available to small entities, considering internal cash flow plus external financial capabilities; or (4) regulatory requirements are likely to result in closures of small entities.

The potential costs of the requirements for medium sized storage vessels were considered as part of the economic impact analysis for the entire regulation. The assessment of the economic impacts of the overall regulation were presented in the April 22, 1994 Federal Register (59 FR 19449). Therefore, the addition of the final provisions to the standard does not alter the conclusion that the standard is not expected to have a significant economic impact on a substantial number of small firms.

Pursuant to the provisions of 5 U.S.C. 605(b), I hereby certify that this attached rule will not have an economic impact on small entities because no additional costs will be incurred.

List of Subjects in 40 CFR Part 63

Environmental protection, Air pollution control, Hazardous substances, Reporting and recordkeeping requirements.

Dated: May 27, 1994.

Carol M. Browner,
Administrator.

For the reasons set out in the preamble, part 63, title 40, chapter I, 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: Sections 101, 112, 114, 116, and 301 of the Clean Air Act (42 U.S.C. 7401, et seq., as amended by Pub. L. 101-549, 104 Stat. 2399).

Subpart G--National Emission Standards for Organic Hazardous Air Pollutants from Synthetic Organic Chemical Manufacturing Industry Process Vents, Storage Vessels, Transfer Operations, and Wastewater

2. Table 5 of the appendix to subpart G is revised to read as follows:

Table 5.--Group 1 Storage Vessels at Existing Sources

Vessel capacity (cubic meters)	Vapor Pressure[1] (kilopascals)
$75 \leq$ capacity < 151	≥ 13.1
$151 \leq$ capacity	≥ 5.2

[1] Maximum true vapor pressure of total organic HAP at storage temperature.

[FR Doc. 94-13666 Filed 6-3-94; 8:45 am]

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Appendix C

EXAMPLE NOTICE OF MACT APPROVAL

Notice of MACT Approval
CFR 40, Part 63, Subpart B
Maximum Achievable Control Technology Emission Limitation
for
Constructed and Reconstructed Sources
under Section 112(j)

This notice establishes practicable, enforceable maximum achievable control technology emission limitation(s) and requirements for *Name of major source* for the MACT-affected emission unit(s) located at *location of all MACT-affected emission units*. The emission limitations and requirements set forth in this document are enforceable on *effective date of notice*.

A. Major Source Information

1. Mailing address of owner or operator:

2. Mailing address for location of major source:

3. Source category or subcategory for major source:

4. MACT-affected emission unit(s): *List all emission unit(s) subject to this Notice of MACT Approval along with the source identification number if applicable.*

5. Type of construction or reconstruction: *Describe the action taken by the owner or operator of the major source that qualifies as the construction of a new affected source or reconstruction of an affected source under the requirements of 40 CFR Part 63, Subpart B, sections 63.50-63.56*

6. Anticipated commencement date for construction or reconstruction:

7. Anticipated start-up date of construction or reconstruction:

8. List of the hazardous air pollutants emitted by MACT-affected emission unit(s): *List all hazardous air pollutants that are or will be emitted from the affected*

emission unit(s). Any pollutant not listed in this section cannot be emitted by the emission unit without an amendment to the Notice of MACT Approval.

B. MACT Emission Limitation

1. The above stated owner or operator shall not exceed the following emission limitation(s) for the above stated MACT-affected emission unit(s). *Write in emission standard or MACT emission limitation for overall hazardous air pollutant emissions from each affected emission unit. If the permitting authority determines that an individual pollutant emission limitation is appropriate, it should also be listed in this section.*

2. The above stated owner or operator shall install and operate the following control technology(s), specific design, equipment, work practice, operational standard, or combination thereof to meet the emission standard or MACT emission limitation listed in paragraph 1 of this section. *List all control technologies to be installed by the owner or operator and which emission units to which the control technologies apply.*

3. The above stated owner or operator shall adhere to the following production or operational parameters for the technologies listed in paragraph 2 of this section. *State all production or operational parameters. For example:*

   > *The owner or operator may, subject to [name of agency] approval, by-pass the emission control device for a limited period of time for purposes such as maintenance of the control device.*
   >
   > *The owner or operator shall operate and maintain the control equipment such that it has a 95% hazardous air pollutant destruction efficiency.*
   >
   > *The owner or operator shall not operate the MACT-affected emission unit for greater than 6 hours in any 24-hour period of time.*

C. Monitoring Requirements

For each MACT emission limitation and operational requirement established in Section B (MACT emission limitation) the above stated owner or operator shall comply with the following monitoring requirements. State all monitoring requirements. *For example:*

> *After installing the control equipment required to comply with Section B.1 visually inspect the internal floating roof, the primary seal, and the secondary seal, before filling the storage vessel*
>
> *The owner or operator shall calibrate, maintain and operate a continuous monitoring system for the measurement of opacity of emissions discharged from the control device required in Section B.2 according to the following procedures: etc.*

D. Reporting and Recordkeeping Requirements

List all reporting and recordkeeping requirements in this section. *For example:*

> *The owner or operator shall maintain at the source for a period of at least 5 years records of the visual inspections, maintenance and repairs performed on each secondary hood system as required in Section B.2.*

E. Other Requirements

1. The above stated owner or operator shall comply with the General Provisions set forth in Subpart A of 40 CFR Part 63, as specified in 40 CFR 63.1(a) and as specified herein by the permitting authority.

2. In addition to the requirements stated in paragraph 1 of this section, the owner or operator will be subject to the following additional requirements. *If there are any specific requirements that the reviewing agency would like to clarify or add, those requirements should also be stated in this paragraph. This paragraph could also include requirements for emergency provisions and start-up and shut-down procedures.*

F. Compliance Certifications

The above stated owner or operator shall certify compliance with the terms and conditions of this notice according to the following procedures: *This section should include a* *description of the terms and conditions that the owner or operator will use to certify compliance, as well as the format and frequency of the certification.*

Appendix D

Federal Register Notice on Final Amendments to Regulations Governing Equivalent Emission Limitations by Permit.

Also see: http://www.epa.gov/ttn/atw/112j/112jaypg.html

TECHNICAL REPORT DATA

(Please read Instructions on reverse before completing)

1. REPORT NO. EPA-453/R-02-001	2.	3. RECIPIENT'S ACCESSION NO.

4. TITLE AND SUBTITLE Guidelines for MACT Determinations under Section 112(j) Requirements	5. REPORT DATE February 2002
	6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S)	8. PERFORMING ORGANIZATION REPORT NO.
9. PERFORMING ORGANIZATION NAME AND ADDRESS Emission Standards Division (C504-03) Office of Air Quality Planning and Standards U.S. Environmental Protection Agency Research Triangle Park, NC 27711	10. PROGRAM ELEMENT NO.
	11. CONTRACT/GRANT NO. 68-D1-0118
12. SPONSORING AGENCY NAME AND ADDRESS Office of Air Quality Planning and Standards U.S. Environmental Protection Agency Research Triangle Park, NC 27711	13. TYPE OF REPORT AND PERIOD COVERED Final
	14. SPONSORING AGENCY CODE EPA/200/04

15. SUPPLEMENTARY NOTES

16. ABSTRACT

The section 112(j) rule, 40 CFR 63 subpart B, requires that permitting authorities develop case-by-case maximum achievable control technology (MACT) for major sources in source categories for which standards are not promulgated within 18 months after the date established under section 112(e). This document provides guidance to those permitting authorities on how to develop case-by-case MACT.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Hazardous Air Pollutants General Provisions Section 112(j)	Air Pollution Control	

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Federal Register

Friday,
May 16, 2003

Part II

Environmental Protection Agency

40 CFR Part 63

National Emission Standards for Hazardous Air Pollutants for Brick and Structural Clay Products Manufacturing; and National Emission Standards for Hazardous Air Pollutants for Clay Ceramics Manufacturing; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[OAR–2002–0054 and OAR–2002–0055, FRL–7459–9]

RIN 2060–A167 and 2060–A168

National Emission Standards for Hazardous Air Pollutants for Brick and Structural Clay Products Manufacturing; and National Emission Standards for Hazardous Air Pollutants for Clay Ceramics Manufacturing

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action promulgates national emission standards for hazardous air pollutants (NESHAP) for new and existing sources at brick and structural clay products (BSCP) manufacturing facilities and NESHAP for new and existing sources at clay ceramics manufacturing facilities. This action will implement section 112(d) of the Clean Air Act (CAA) by requiring major sources to meet hazardous air pollutant (HAP) emission standards reflecting the application of the maximum achievable control technology (MACT). The two subparts will protect air quality and promote the public health by reducing emissions of several of the HAP listed in section 112(b)(1) of the CAA. The rules will reduce HAP emissions from existing sources by 2,300 tons per year nationwide, with hydrogen fluoride (HF) and hydrogen chloride (HCl) accounting for 2,290 tons per year (99.6 percent) of the total HAP emissions reductions from existing sources. The associated metals (antimony, arsenic, beryllium, cadmium, chromium, cobalt, mercury, manganese, nickel, lead, and selenium) reductions from existing sources account for approximately 6 tons per year nationwide (0.4 percent). Exposure to these substances has been demonstrated to cause adverse health effects such as irritation of the lung, skin, and mucus membranes, effects on the central nervous system, and kidney damage. The EPA has classified three of the HAP as known human carcinogens, four as probable human carcinogens, and one as a possible human carcinogen. We estimate that the two subparts will reduce nationwide emissions of HAP from these facilities by approximately 2,100 megagrams per year (Mg/yr)(2,300 tons per year (tpy)), a reduction of approximately 35 percent from the current level of emissions.

EFFECTIVE DATE: The final rule is effective May 16, 2003.

ADDRESSES: Docket No. OAR–2002–0054 contains supporting documentation used in developing the final BSCP rule. Docket No. OAR–2002–0055 contains supporting documentation used in developing the final clay ceramics rule. The dockets are located at the Air and Radiation Docket and Information Center in the EPA Docket Center, (EPA/DC) EPA West, Room B102, 1301 Constitution Avenue, NW., Washington, DC 20460, telephone (202) 566–1744. The dockets are available for public inspection from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding Federal holidays.

FOR FURTHER INFORMATION CONTACT: For further information concerning applicability and rule determinations, contact the appropriate State or local agency representative. If no State or local representative is available, contact the EPA Regional Office staff listed in 40 CFR 63.13. For information concerning the analyses performed in developing the final rules, contact Ms. Mary Johnson, Combustion Group, Emission Standards Division (MC–C439–01), U.S. EPA, Research Triangle Park, North Carolina 27711, telephone number (919) 541–5025, e-mail address: *johnson.mary@epa.gov.*

SUPPLEMENTARY INFORMATION: *Regulated Entities.* Entities potentially regulated by this action are those industrial facilities that manufacture BSCP and clay ceramics. Brick and structural clay products manufacturing is classified under Standard Industrial Classification (SIC) codes 3251, Brick and Structural Clay Tile; 3253, Ceramic Wall and Floor Tile; and 3259, Other Structural Clay Products. The North American Industry Classification System (NAICS) codes for BSCP manufacturing are 327121, Brick and Structural Clay Tile; 327122, Ceramic Wall and Floor Tile Manufacturing; and 327123, Other Structural Clay Products. Clay ceramics manufacturing is classified under SIC codes 3253, Ceramic Wall and Floor Tile; and 3261, Vitreous Plumbing Fixtures (Sanitaryware). The NAICS codes for clay ceramics manufacturing are 327122, Ceramic Wall and Floor Tile Manufacturing; and 327111, Vitreous China Plumbing Fixture and China and Earthenware Bathroom Accessories Manufacturing. Regulated categories and entities are shown in Table 1 of this preamble.

TABLE 1.—REGULATED CATEGORIES AND ENTITIES

Category	SIC	NAICS	Examples of potentially regulated entities
Industrial	3251	327121	Brick and structural clay tile manufacturing facilities (BSCP NESHAP)
Industrial	3253	327122	Ceramic wall and floor tile manufacturing facilities (Clay Ceramics NESHAP) and extruded tile manufacturing facilities (BSCP NESHAP).
Industrial	3259	327123	Other structural clay products manufacturing facilities (BSCP NESHAP)
Industrial	3261	327111	Vitreous plumbing fixtures (sanitaryware) manufacturing facilities (Clay Ceramics NESHAP).

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this action. To determine whether your facility is regulated by this action, you should examine the applicability criteria in § 63.8385 of today's final BSCP rule and § 63.8535 of today's final clay ceramics 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.**

Electronic Docket (E-Docket). The EPA has established official public dockets for this action under Docket ID No. OAR–2002–0054 for the final BSCP rule and Docket ID No. OAR–2002–0055 for the final clay ceramics rule. The official public dockets are the collection of materials that is available for public viewing at the EPA Docket Center (Air Docket), EPA West, Room B102, 1301 Constitution Avenue, NW., Washington, DC 20460. The Docket Center 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 Docket is (202) 566–1742. A reasonable fee may be charged for copying docket materials.

Electronic Access. Electronic versions of the public dockets are 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 indexes of the contents of the official public dockets, and to access those documents in the public dockets that are available electronically. Once in the system, select ''search'' and key in the appropriate docket identification number. Although not all docket materials may be available electronically, you may still access any of the publicly available docket materials through the docket facility identified in this document.

Worldwide Web (WWW). In addition to being available in the dockets, an electronic copy of today's document also will be available on the WWW. Following the Administrator's signature, a copy of this action will be posted at *www.epa.gov/ttn/oarpg* on EPA's Technology Transfer Network (TTN) policy and guidance page for newly proposed or promulgated rules. 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 final rule is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit by July 15, 2003. Under section 307(d)(7)(B) of the CAA, only an objection to the final rule that was raised with reasonable specificity during the period for public comment can be raised during judicial review. Moreover, under section 307(b)(2) of the CAA, the requirements established by the final rule may not be challenged separately in any civil or criminal proceedings brought by EPA to enforce the requirements.

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

I. Background

A. What Is the Source of Authority for Development of NESHAP?

Section 112 of the CAA requires us to list categories and subcategories of major and area sources of HAP and to establish NESHAP for the listed source categories and subcategories. Clay products manufacturing was listed as a category of major sources on the initial source category list published in the **Federal Register** on July 16, 1992 (57 FR 31576). In the July 22, 2002 **Federal Register** notice (67 FR 47894) that proposed NESHAP for BSCP manufacturing and clay ceramics manufacturing, the clay products manufacturing source category was replaced by the BSCP manufacturing source category and the clay ceramics manufacturing source category. Today's action contains final rules for the two source categories. Major sources of HAP are those stationary sources or groups of stationary sources that are located within a contiguous area and under common control that emit or have the potential to emit considering controls, in the aggregate, 9.07 Mg/yr (10 tpy) or more of any one HAP or 22.68 Mg/yr (25 tpy) or more of any combination of HAP. Area sources are those stationary sources that are not major sources.

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

Section 112 of the CAA requires that we establish NESHAP for the control of HAP from both new and existing major sources. The CAA requires the NESHAP to reflect the maximum degree of reduction in emissions of HAP that is achievable. This level of control is commonly referred to as MACT.

The MACT floor is the minimum control level allowed for NESHAP and is defined under section 112(d)(3) of the CAA. In essence, the MACT floor ensures that the standards are set at a level that assures that all major sources achieve the level of control at least as stringent as that already achieved by the better-controlled and lower-emitting sources in each source category or subcategory. For new sources, the MACT floor cannot be less stringent than the emission control that is achieved in practice by the best-controlled similar source. The MACT standards for existing sources can be less stringent than standards for new sources, but they cannot be less stringent than the average emission limitation achieved by the best-performing 12 percent of existing sources in the category or subcategory for which the Administrator has emissions information (or the best-performing 5 sources for which the Administrator has or could reasonably obtain emissions information for categories or subcategories with fewer than 30 sources).

In developing MACT, we also consider control options that are more stringent than the floor. We may establish standards more stringent than the floor based on the consideration of cost of achieving the emissions reductions, any health and environmental impacts, and energy requirements.

C. How Were the Final Rules Developed?

We proposed standards for BSCP manufacturing and clay ceramics manufacturing on July 22, 2002 (67 FR 47894). The preamble for the proposed standards described the rationale for the proposed standards. Public comments were solicited at the time of proposal. The public comment period lasted from July 22, 2002 to September 20, 2002. Industry representatives, regulatory agencies, environmental groups, and the general public were given the opportunity to comment on the proposed rules and to provide additional information during the public comment period. We also offered at proposal the opportunity for oral presentation of data, views, or arguments concerning the proposed rules. A public hearing on the proposed BSCP rule was held on August 21, 2002, during which 21 presentations were made. Following the public hearing, we met with representatives of industry and environmental groups on several occasions.

We received a total of 80 public comment letters on the proposed BSCP rule and 9 public comments letters on the proposed clay ceramics rule. Comments were submitted by industry trade associations, BSCP and clay ceramics manufacturing companies, State regulatory agencies and their representatives, and environmental groups. Today's final rules reflect our consideration of all of the comments received. Major public comments on the proposed rules, along with our responses to those comments, are summarized in this preamble.

D. What Are the Health Effects of Pollutants Emitted From the Brick and Structural Clay Products Manufacturing and Clay Ceramics Manufacturing Source Categories?

Today's proposed rules protect air quality and promote the public health by reducing emissions of some of the HAP listed in section 112(b)(1) of the CAA. Emissions data collected during development of the proposed rules show that HF, HCl, and small amounts of metals (antimony, arsenic, beryllium, cadmium, chromium, cobalt, mercury, manganese, nickel, lead, and selenium) are emitted from BSCP and clay ceramics manufacturing facilities. Exposure to 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, four as probable human carcinogens, and one as a possible human carcinogen. We do not know the extent to which the adverse health effects described above occur, or if any adverse effects occur, in the populations surrounding these facilities. However, to the extent the adverse effects do occur, today's proposed rules would reduce emissions and subsequent exposures. The majority of the emissions reductions from this rule are HF (1900 tons per year nationwide) and HCl (390 tons per year nationwide), while the rule will only reduce emissions of the HAP metals listed below by a small amount (approximately 6 tons nationwide per year).

1. Hydrogen Fluoride

Acute (short-term) inhalation exposure to gaseous HF can cause severe respiratory damage in humans, including severe irritation and pulmonary edema. 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 or mottling, while very high exposures through drinking water or air can result in crippling skeletal fluorosis. One study reported menstrual irregularities in women occupationally exposed to fluoride. We have not classified HF for carcinogenicity.

2. Hydrogen Chloride

Hydrogen chloride, also called hydrochloric acid, is corrosive to the eyes, skin, and mucous membranes. Acute (short-term) inhalation exposure may cause eye, nose, and respiratory tract irritation and inflammation and pulmonary edema in humans. Chronic (long-term) occupational exposure to HCl has been reported to cause gastritis, bronchitis, and dermatitis in workers. Prolonged exposure to low concentrations may also cause dental discoloration and erosion. No information is available on the reproductive or developmental effects of HCl in humans. In rats exposed to HCl by inhalation, altered estrus cycles have been reported in females and increased fetal mortality and decreased fetal weight have been reported in offspring. We have not classified HCl for carcinogenicity.

3. Antimony

Acute (short-term) exposure to antimony by inhalation in humans results in effects on the skin and eyes. Respiratory effects, such as inflammation of the lungs, chronic bronchitis, and chronic emphysema, are the primary effects noted from chronic (long-term) exposure to antimony in humans via inhalation. Human studies are inconclusive regarding antimony exposure and cancer, while animal studies have reported lung tumors in rats exposed to antimony trioxide via inhalation. Effects of oral exposure to antimony are not well-described, but a single study has reported decreased longevity and changes in serum glucose and cholesterol in rats. We have not classified antimony for carcinogenicity.

4. Arsenic

Acute (short-term) high-level inhalation exposure to arsenic dust or fumes has resulted in gastrointestinal effects (nausea, diarrhea, abdominal pain), and central and peripheral nervous system disorders. 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 of women working at or living near metal smelters and an increased risk of reproductive effects, such as spontaneous abortions. 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. We have classified inorganic arsenic as a Group A, human carcinogen.

5. Beryllium

Acute (short-term) inhalation exposure to high levels of beryllium has been observed to cause inflammation of the lungs or acute pneumonitis (reddening and swelling of the lungs) in humans; after exposure ends, these symptoms may be reversible. Chronic (long-term) inhalation exposure of humans to beryllium has been reported to cause chronic beryllium disease (berylliosis), in which granulomatous (noncancerous) lesions develop in the lung. Inhalation exposure to 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. Oral exposure to beryllium was found to cause stomach lesions in dogs, but effects on humans are not well-described. We have classified beryllium as a Group B1, probable human carcinogen, when inhaled; data are inadequate to determine whether beryllium is carcinogenic when ingested.

6. Cadmium

The acute (short-term) effects of cadmium inhalation in humans consist mainly of effects on the lung, such as pulmonary irritation. 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 in animals, resulting in fetal malformations and other effects, but no conclusive evidence exists in humans. An association between cadmium inhalation exposure and an increased risk of lung cancer has been reported from human studies, but these studies are inconclusive due to confounding factors. Animal studies have demonstrated an increase in lung cancer from long-term inhalation exposure to cadmium. We have classified cadmium as a Group B1, probable human carcinogen when inhaled; data are inadequate to determine whether cadmium is carcinogenic when ingested.

7. Chromium

Chromium may be emitted 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 acute (short-term) and chronic (long-term) inhalation exposures. Shortness of breath, coughing, and wheezing have been reported from acute exposure to chromium VI, while perforations and ulcerations of the septum, bronchitis, decreased pulmonary function, pneumonia, and other respiratory effects have been noted from chronic exposure. 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. We have classified chromium VI as a Group A, human carcinogen by the inhalation exposure route. Oral exposure of humans to chromium VI has been reported to cause sores in the mouth, gastrointestinal effects, and elevated white blood cell counts. Animal studies of oral chromium VI exposure have reported testicular degeneration and fetal damage in mice and rats. Chromium IV is also a potent contact sensitizer, producing allergic dermatitis in previously-exposed humans. Data are inadequate to determine if chromium VI is carcinogenic by oral exposure.

Chromium III is much 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 oral intake of 50 to 200 micrograms per day (μg/d) recommended for an adult. Data on adverse effects of high oral exposures of chromium III are not available for humans, but a study with mice suggests possible damage to the male reproductive tract. We have not classified chromium III for carcinogenicity.

8. Cobalt

Acute (short-term) exposure to high levels of cobalt by inhalation in humans and animals results in respiratory effects such as a significant decrease in ventilatory function, congestion, edema, and hemorrhage of the lung. Respiratory effects are also the major effects noted from chronic (long-term) exposure to cobalt by inhalation, with respiratory irritation, wheezing, asthma, pneumonia, and fibrosis noted. Cardiac effects, congestion of the liver, kidneys, and conjunctiva, and immunological effects have also been associated with cobalt inhalation in humans. Cobalt is an essential element in humans, as a constituent of vitamin B12, but excessive oral intake has been reported to damage the heart, and to cause gastrointestinal effects and contact dermatitis. Human and animal studies are inconclusive with respect to potential carcinogenicity of cobalt. We have not classified cobalt for carcinogenicity.

9. Mercury

Mercury exists in three forms: Elemental mercury, inorganic mercury compounds (primarily mercuric chloride), and organic mercury compounds (primarily methylmercury). Each form exhibits different health effects. Brick, structural clay products, and clay ceramics manufacturing may release elemental or inorganic mercury, but not methylmercury. However, elemental and inorganic mercury are deposited on surface water, where they are converted to methylmercury, an important food contaminant.

Acute (short-term) exposure to high levels of elemental mercury in humans results in central nervous system (CNS) effects such as tremors, mood changes, and slowed sensory and motor nerve function. High inhalation exposures can also cause kidney damage and effects on the gastrointestinal tract and respiratory system. Chronic (long-term) inhalation exposure to elemental mercury in humans also affects the CNS, with effects such as increased excitability, irritability, excessive shyness, and tremors. Data on toxic effects of oral exposure to elemental mercury are sparse. We have not classified elemental mercury for carcinogenicity.

Acute exposure to inorganic mercury by the oral route may result in effects such as nausea, vomiting, and severe abdominal pain. The major effect from chronic exposure, either oral or inhalation, to inorganic mercury is kidney damage. 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 forestomach, thyroid, and renal tumors in experimental animals. We have classified mercuric chloride as a Group C, possible human carcinogen.

Both acute and chronic oral exposure to methylmercury have been found to cause developmental damage to the central nervous system in fetuses and children, with effects including mental retardation, deafness, blindness, and cerebral palsy. Lower exposures may cause developmental delays and abnormal reflexes. The most important source of methylmercury exposure for most people is eating fish. Although fish is an important part of a balanced diet federal and state fish advisories recommend limiting intake of certain fish that contain elevated methylmercury levels.

10. 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 inhalation 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. Manganism, characterized by feelings of weakness and lethargy, tremors, a mask-like face, and psychological disturbances, may result from chronic exposure to higher levels. Impotence and loss of libido have been noted in male workers afflicted with manganism attributed to inhalation exposures. We have classified manganese as Group D, not classifiable as to human carcinogenicity.

11. 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, hands, 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. Human and animal studies have reported an increased risk of lung and nasal cancers from exposure to nickel refinery dusts and nickel subsulfide. Animal inhalation studies of soluble nickel compounds (*i.e.*, nickel carbonyl) have reported lung tumors. Dermal exposure to nickel may produce contact dermatitis. Adverse effects of oral nickel exposure are not well-described. We have classified nickel refinery dust and nickel subsulfide as Group A, human carcinogens, and nickel carbonyl as a Group B2, probable human carcinogen, by inhalation exposure.

12. Lead

Lead is a very toxic element, causing a variety of effects at low oral or inhaled dose levels. Brain damage, kidney damage, and gastrointestinal distress may occur from acute (short-term) exposure to high levels of lead in humans. Chronic (long-term) exposure to lead in humans results in effects on the blood, 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 lead exposure by the oral route. We have classified lead as a Group B2, probable human carcinogen.

13. Selenium

Selenium is a naturally occurring substance that is toxic at high concentrations but is also a nutritionally essential element. Acute (short-term) exposure to elemental selenium, hydrogen selenide, and selenium dioxide by inhalation results primarily in respiratory effects, such as irritation of the mucous membranes, pulmonary edema, severe bronchitis, and bronchial pneumonia. 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 Responses to Major Comments and Changes to the Brick and Structural Clay Products Manufacturing Proposed NESHAP

In response to the public comments received on the proposed BSCP rule, we made several changes in developing today's final BSCP rule. The major comments and our responses and rule changes are summarized in the following sections. A more detailed summary can be found in the Response-to-Comments document, which is available from several sources (see SUPPLEMENTARY INFORMATION section).

A. Air Pollution Control Devices

The most significant change to the proposed BSCP rule concerns our conclusions regarding the effective application of air pollution control devices (APCD) to existing kilns. The EPA received numerous comments from industry representatives, kiln manufacturers, and air pollution control device vendors on issues related to the application and performance of APCD. The MACT floor in the proposed rule was based on the use of dry lime injection fabric filters (DIFF), dry lime scrubber/fabric filters (DLS/FF), or wet scrubbers (WS). Another technology commonly used to control emissions from brick kilns, dry limestone adsorbers (DLA), was not considered to be a MACT floor technology at the time of proposal because we had concerns with monitoring options and our data indicated that the DLA could not achieve HAP emissions reductions equivalent to the reductions achieved by DIFF, DLS/FF, or WS technologies. However, as discussed in the paragraphs below, many commenters reported disadvantages of the DIFF, DLS/FF, and WS technologies for BSCP kilns and provided information to address our concerns about DLA technology. Consequently, the final rule allows some sources to use the DLA technology.

Several commenters argued that DIFF, DLS/FF, and WS technologies are not proven or commercially available for BSCP kilns. Commenters pointed out that, with the exception of one facility, full-scale WS have never been used on

BSCP kilns, although some short-term pilot tests of WS have been conducted. The commenters pointed out that injection systems (such as DIFF and DLS/FF) and wet control devices need a certain airflow to operate properly, and different products may require different airflows, some of which could be outside of the range within which the APCD operates properly. In addition, commenters pointed out that during kiln slowdowns (which could be caused by a situation such as an economic slowdown), the APCD may not be able to operate at all because of reduced kiln airflow.

Several commenters expressed concerns about waste disposal. Commenters stated that DIFF and DLS/FF systems produce large amounts of solid waste that is difficult and expensive to dispose of. Commenters stated that WS would not be viable options for many BSCP plants because of wastewater treatment issues (*e.g.*, limited or no sewer access, wastewater treatment costs). Commenters added that recycling of WS wastewater back into the brick body is not an option because of problems created by the soluble salts in the water (*e.g.*, scumming and efflorescence) and because the volume of wastewater generated would exceed process water needs even if recycling were possible.

Commenters also raised concerns about retrofitting existing BSCP kilns with DIFF, DLS/FF, and WS technologies. Commenters pointed out that brick color, the primary factor in brick sales, is affected by kiln airflow. Thus, retrofitting with an APCD that changes the kiln airflow would change the recipes for the manufacture of brick in a tunnel kiln. Thus, years of experience in the colors produced by the unique firing characteristics of a kiln would be lost. Implications are serious if a facility cannot match its existing product line.

The commenters also charged that we did not account for other retrofitting problems associated with installing DIFF, DLS/FF, or WS on older kilns, and the costs associated with these problems. Commenters also described how attempts at retrofitting kilns with these APCD have resulted in significant amounts of kiln downtime and permanent reductions in kiln production capacities. As stated by the commenters, none of the retrofits have been entirely successful in terms of reducing emissions while not disrupting the production process, and several have had dramatic negative impacts on the production process. At one facility that retrofitted two kilns with DIFF, the capacities of the two kilns decreased from 13.5 cars per day to 12.2 cars per day because of changes in the kiln airflow that resulted from the retrofit. This resulted in a loss of revenue of about $1 million per year. Another retrofit DIFF (multi-stage injection system) installation at a different facility was reported to be extremely problematic, and the cost of the APCD, which was originally estimated at $1 million, is now over $2 million and the system is still not operating correctly more than 2 years later. The facility has experienced numerous problems with the basic design of the unit, including improperly designed dampers and reagent feeding systems. A facility representative stated that the problems are largely due to the fact that few systems have been developed for brick kiln operations; therefore, vendors are still learning (often on the industry's nickel) how to design these systems. In the facility's public comments, they stated that they plan to never build another hot baghouse (DIFF or DLS/FF) due to the massive operating problems associated with them. A retrofit DLS/FF system, the only one that has been attempted in the U.S. to date, also was problematic. The facility stated that they have experienced maintenance and material quality problems that have resulted in kiln downtime. The facility added that the problems stem from the fact that the system is a prototype without a substantial operational, troubleshooting and maintenance history, which has left the facility in the position of having to diagnose and solve the problems as the system operates. In addition, the company that installed this system is no longer quoting systems to the BSCP industry.

Numerous commenters recommended that EPA allow use of DLA. The commenters described the operating benefits of DLA, including ease of operation, low operating cost, little down time, and the ability to handle kiln fluctuations with changing throughputs. Most importantly, DLA do not impact kiln operation. The commenters pointed out that DLA do not require a minimum airflow like DIFF, DLS/FF, or WS technologies. One commenter pointed out that once a DLA is designed for maximum airflow, any fluctuations below this maximum only create more contact time between the kiln exhaust gases and the limestone, which would likely increase the effectiveness of the DLA and would not impact the operation of the kiln. The commenters pointed out that DLA have been used extensively in Europe for many years and also are the most prevalent APCD used in the BSCP industry in the United States. Many commenters stated that DLA should be allowed if they can meet the BSCP standards. The commenters indicated that plants should not have to request site-specific monitoring parameters for DLA because they are the most prevalent technology. In addition, some commenters discussed the high costs and limited additional HAP reduction associated with replacing existing DLA with a DIFF system.

Several commenters felt that EPA disregarded or ''bashed'' DLA and disagreed with EPA's conclusions regarding DLA in the preamble to the proposed rule. Specifically, the commenters disagreed that: DLA generate particulate matter (PM) emissions; long-term test data that demonstrate DLA performance over the life of the sorbent are not available; DLA limestone is not continuously replaced; and the performance of DLA decreases as the sorbent is re-used because the ability of the sorbent to adsorb HF and HCl decreases.

We disagree with commenters that the use of DIFF has not been proven in the brick industry. The DIFF and DLS/FF systems are a proven control technology for kilns with a given minimum airflow rate. We do, however, believe that retrofitting existing kilns with DIFF or DLS/FF systems is not feasible in many cases. We recognize that WS may not be practical or low-cost for most facilities, but believe they could be a legitimate option for some facilities (*e.g.*, facilities with sewer access). We acknowledge that retrofitting existing BSCP kilns with certain APCD (particularly those that affect kiln airflow) can alter time-honored recipes for brick color, thereby changing the product. We acknowledge that DLA are used extensively around the world to control emissions from brick kilns. In developing the description of DLA technology for the preamble to the proposed rule, we used the technical data available to us at the time. We had no intention of ''bashing'' DLA but simply reported the data at hand.

After consideration of the comments received regarding DIFF, DLS/FF, WS, and DLA technologies, we have come to new conclusions regarding the effective application of these devices. We now believe that DLA are the only currently available technology that can be used to retrofit existing kilns without potentially significant impacts on the production process, and we have revised today's final rule accordingly. In addition, we believe that, because of the retrofit concerns that we have identified, it is not technologically and economically feasible for an existing small tunnel kiln that would otherwise meet the criteria for reconstruction in 40 CFR 63.2 and whose design capacity is increased such that it is equal to or greater than 9.07 Mg/hr (10 tph) of fired product (for the remainder of this preamble, these sources will be referred to as ''existing small kilns that are rebuilt such that they become large kilns'') to meet the relevant standards (*i.e.*, new source MACT) by retrofitting with a DIFF, DLS/FF, or WS. In addition, we believe that it is not technologically and economically feasible for an existing large DLA-controlled kiln that would otherwise meet the criteria for reconstruction in 40 CFR 63.2 (for the remainder of this preamble, these sources will be referred to as ''existing large DLA-controlled kilns that are rebuilt'') to meet the relevant (*i.e.*, new source MACT) standards by retrofitting with a DIFF, DLS/FF, or WS. Accordingly, we have added regulatory language in 40 CFR 63.8390(i) to provide that an existing small kiln that is rebuilt such that it becomes a large kiln and an existing large DLA-controlled tunnel kiln that is rebuilt do not meet the definition of reconstruction in 40 CFR 63.2 and are not subject to the same requirements as new and reconstructed large tunnel kilns. However, it is technologically and economically feasible for both types of kilns described in 40 CFR 63.8390(i) to retrofit with a DLA (or to continue operating an existing DLA) and we have revised today's final rule to require that such kilns meet emission limits that correspond to the level of control provided by a DLA. We continue to believe that DIFF, DLS/FF, and WS are appropriate technologies for new large tunnel kilns and for reconstructed large tunnel kilns that were equipped with DIFF, DLS/FF, or WS prior to reconstruction. However, DLA are the only APCD that have been demonstrated on small tunnel kilns (which have smaller airflows than large tunnel kilns), and, therefore, the requirements for new and reconstructed small tunnel kilns are based on the level of control that can be achieved by a DLA. We note that facilities have the flexibility to select any control device or technique that ensures that emissions from their brick kilns are in compliance with the emission limits set forth in the final rule. Each of the APCD described above have advantages and disadvantages to their use, and the selection of the APCD to meet the requirements of the final rule will be dependent on site-specific parameters.

B. Affected Source

1. Production-Rate Limit

The proposed rule subcategorized tunnel kilns based on a 9.07 Mg/hr (10 tph) design capacity. We requested comment on the appropriate design capacity-based subcategorization level in the preamble to the proposed rule. We received numerous comments regarding subcategorization of tunnel kilns. While some commenters agreed with the 9.07 Mg/hr (10 tph) distinction among tunnel kiln subcategories, several commenters thought that the 9.07 Mg/hr (10 tph) limit was arbitrarily assigned. The commenters charged that EPA did not use all available data in determining the appropriate size cutoff. Many commenters argued that the design capacity limit should be higher based on available data (*i.e.*, 10.1 Mg/hr (11.1 tph) or 12.1 Mg/hr (13.3 tph)). The commenters disagreed that the cutoff should be rounded down from 10.1 Mg/hr (11.1 tph) to 9.07 Mg/hr (10 tph).

Some commenters noted that a design capacity distinction gives a competitive advantage to facilities operating smaller kilns. One commenter disagreed that there was a technological basis for differentiating among tunnel kilns producing above or below 9.07 Mg/hr (10 tph). The commenter stated that EPA may not subcategorize tunnel kilns to reduce costs.

Through subcategorization, we are able to define subsets of similar emission sources within a source category if differences in emissions characteristics, processes, APCD viability, or opportunities for pollution prevention exist within the source category. 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 BSCP source category. We first subcategorized kilns based on type (*i.e.*, periodic kilns versus tunnel kilns). We then further subcategorized tunnel kilns based on kiln size. Our distinctions are based on technological differences in the equipment. For example, periodic kilns are smaller than tunnel kilns and operate in batch cycles, whereas tunnel kilns operate continuously. There are also differences in the effective application of air pollution controls. To our knowledge, HAP emissions from periodic kilns have not successfully been controlled. Similarly, we distinguished between tunnel kilns with design capacities above and below 9.07 Mg/hr (10 tph) at proposal in part because the APCD we believed to be the best performers (DIFF, DLS/FF, and WS) were not demonstrated on existing tunnel kilns with design capacities below roughly 9.07 Mg/hr (10 tph). For the reasons discussed below, we revisited the appropriate subcategorization level in response to comments on the proposal when developing today's final rule. While we continue to believe that 9.07 Mg/hr (10 tph) is the appropriate subcategorization level, our reasons for choosing that level have changed since proposal in light of new information that we received during the public comment period about DLA controls and the three proposed MACT controls (DIFF, DLS/FF, and WS).

As discussed earlier, numerous commenters pointed out serious concerns regarding retrofitting existing kilns with APCD such as DIFF, DLS/FF, and WS. Therefore, we now consider DLA to be the only currently available technology that can be used to retrofit existing kilns, including existing small kilns that are rebuilt such that they become large kilns and existing large DLA-controlled kilns that are rebuilt, without potentially significant impacts on the production process.

In response to comments suggesting that we include new data in our analyses, we updated our data base with information on new kilns, new APCD (except those controls that we consider to achieve the lowest achievable emission rate (LAER) as specified in section 112(d)(3)(A) of the CAA), changes in kiln capacities, and changes in facility ownership. We used the information submitted by commenters and made followup calls to States and individual facilities for additional clarification as necessary to update our data base.

We used our updated data base in reevaluating all aspects of the proposed standards. The smallest tunnel kiln with MACT floor controls (*i.e.*, with DLA controls reflecting the existing source MACT floor under today's final rule) in our updated database has a capacity of 8.3 Mg/hr (9.1 tph). Rounding up to the nearest integer, based on current application of APCD to BSCP tunnel kilns, we believe that 9.07 Mg/hr (10 tph) continues to be an appropriate subcategorization level. Commenters have stated that a smaller tunnel kiln (*e.g.*, 4.5 Mg/hr (5 tph) capacity) is dissimilar from a larger tunnel kiln (*e.g.*, 13.6 Mg/hr (15 tph) capacity), especially with regard to the airflow, which is a key operating parameter for APCD. Airflow is particularly important for lime injection-type systems (DIFF and DLS/FF), because the injected lime is carried through the reaction chamber (or duct) by the kiln exhaust gas. For a given lime injection rate, if a minimum exhaust flow is not maintained, the sorbent can settle in the duct work and cause APCD malfunction. Furthermore, APCD malfunctions can affect the airflow within the kiln, and can destroy product that is in the kiln. We believe that DIFF and DLS/FF systems, if attempted on smaller kilns, would experience more difficulties with respect to airflow than systems on larger kilns because as the design airflow decreases, the acceptable operating range also would be expected to decrease. Any fluctuation in airflow would be expected to have a greater impact on APCD operation as the size of the system decreases. Given the technological concerns and the capacities of currently-controlled tunnel kilns, we maintain that a design capacity-based subcategorization level of 9.07 Mg/hr (10 tph) is appropriate for existing tunnel kilns.

We acknowledge the comments suggesting that 10.1 Mg/hr (11.1 tph) should be the size cutoff based on the smallest DIFF-controlled tunnel kiln. However, because we now consider that the performance of a DLA represents the MACT floor for existing sources (and DIFF, DLS/FF, and WS also can meet the emission limits), we considered the smallest non-LAER DLA-controlled kiln in setting the subcategorization level. We disagree that 12.1 Mg/hr (13.3 tph) would have been the proper level for proposal or for the final rule. We believe that consideration of technological differences and the effective application of APCD to kilns of different sizes is the appropriate method of selecting a subcategorization level. We maintain that 9.07 Mg/hr (10 tph) is appropriate.

We understand that, regardless of the particular subcategorization level selected, there will be facilities that operate kilns with throughputs slightly above the level and some that operate kilns at slightly below the level. Facilities operating kilns slightly above the subcategorization level have the option of accepting a federally enforceable permit limit to limit their throughput to below the level. Facilities operating just below the level must make careful decisions regarding expansion of their kilns. We acknowledge that facilities operating near the subcategorization level must make decisions regarding permit limits and expansions based on facility-specific considerations (*e.g.*, control costs, impact on revenue). However, as some commenters have pointed out, cost is not an appropriate criteria for us to use in establishing subcategories, because our discretion for establishing subcategories is limited, under the CAA, to distinguishing among classes, types, and sizes of sources.

2. R&D Kiln Definition

One commenter requested that we change the definition of research and development (R&D) kiln so that it is consistent with the definition of R&D in section 112(c)(7) of the CAA and most other NESHAP. Therefore, today's final rule includes a revised definition of research and development kiln that is consistent with section 112(c)(7) of the CAA and other NESHAP.

C. Existing Source MACT

1. Consideration of Synthetic Area Sources in the MACT Floor Determinations for Existing Sources

In the preamble to the proposed BSCP rule, we requested comment on inclusion of synthetic area sources (also called synthetic minor sources) in the MACT floor determinations for existing tunnel kilns. For the remainder of this preamble, we will refer to these sources as synthetic minor sources. Synthetic minor sources are those facilities that emit fewer than 10 tons per year of any HAP and fewer than 25 tons per year of any combination of HAP because they use some emission control device (or devices), the operation of which is required by a Federally Enforceable State Operating Permit (FESOP). In the absence of such controls, these sources would be major.

Inclusion of synthetic minor sources in the MACT floor determination was an issue prior to proposal because whether or not synthetic minor sources were included would affect the level of control represented by the floor determinations for existing large tunnel kilns (*i.e.*, tunnel kilns with design capacities equal to or greater than 9.07 Mg/hr (10 tph)). Had synthetic minor sources been excluded, the MACT floor for existing tunnel kilns would have been ''no emissions reductions.'' With synthetic minor sources included (as we proposed), the MACT floor for existing tunnel kilns was based on a DIFF, DLS/FF or WS.

Industry representatives asserted, prior to proposal, that the BSCP MACT floor determination should not include synthetic minor sources. We rejected the idea of excluding synthetic minor sources from the MACT floor determination for several reasons discussed in the preamble to the proposed rule. (See 67 FR 47894, 47911–47912, July 22, 2002.) Nevertheless, because of the industry representatives' arguments, we requested comment from all interested parties on inclusion of synthetic minor sources in MACT floor determinations.

Following proposal, numerous industry representatives commented on the issue of whether to include synthetic minor sources in MACT floor determinations. The industry representatives commented that only major sources are included in the listed BSCP source category, and therefore, only major sources are to be used in the MACT floor determination. The commenters referenced section 112(a)(1) of the CAA, which defines major source as a source that ''emits or has the potential to emit *considering controls* 10 tons per year * * *.'' (emphasis added), and stated that by definition, synthetic minor sources are not major sources. The commenters noted that EPA did not include true area sources (or minor sources) in the MACT floor determination and stated that synthetic minor sources should be treated similarly for purposes of establishing MACT floors.

An environmental group also commented on the issue of including synthetic minor sources in MACT floor determinations. The commenter supported EPA's decision to include synthetic minor sources in the MACT floor for BSCP. The commenter stated that the CAA requires EPA to include synthetic minor sources in MACT floor determinations. The commenter stated that excluding consideration of the best-controlled sources (which became synthetic minor sources as a result of effective controls) would contradict the CAA section 112(d) MACT floor methodology established by Congress. The commenter argued that such exclusion would weaken emission standards required for existing sources, and increase the levels of air toxics released into the environment.

Section 112(d) of the CAA directs us to establish emission standards for each category or subcategory of major sources and minor sources of HAP listed for regulation pursuant to section 112(c) of the CAA. Each such standard must reflect a minimum level of control known as the MACT floor. (See CAA section 112(d).) However, section 112 of the CAA does not specifically address synthetic minor or synthetic area sources, which include those sources that emit fewer than 10 tons per year of any HAP or fewer than 25 tons per year of any combination of HAP because they use some emission control device(s), pollution prevention techniques or other measures (collectively referred to as controls in this preamble) adopted under Federal or State regulations. If not for the enforceable controls they have implemented, synthetic minor sources would be major sources under section 112 of the CAA.

We believe that the better interpretation of the CAA's plain language and legislative history requires that synthetic minor sources be included in MACT floor determinations. First, the plain language of the statute makes clear that our MACT floor determinations are to reflect the best sources in a category. For new sources in a category or subcategory, the MACT floor shall not be less stringent than the emission control that is achieved in practice by the *best-controlled* similar source, as determined by EPA. (See CAA section 112(d)(3), emphasis added.) For existing sources in a category or subcategory with 30 or more sources, the MACT floor may be less stringent than the floor for new sources in the same category or subcategory but shall not be less stringent than the average emission limitation achieved by the *best performing* 12 percent of the existing sources (for which the Administrator has emissions information). (See CAA section 112(d)(3)(A), emphasis added.[1]) Thus, section 112(d)(3) of the CAA requires that MACT floors reflect what the best-controlled new sources and the best-performing existing sources achieve in practice. These phrases contain no exemptions and are not limited by references to sources with or without controls. Therefore, they suggest that all of the best-controlled or best-performing sources should be considered in MACT floor determinations, regardless of whether or not such sources rely upon controls.

Furthermore, section 112(d)(3) of the CAA expressly excludes certain sources that meet LAER requirements from MACT floor determinations for existing sources. (See CAA section 112(d)(3)(A).) The fact that Congress expressly excluded such LAER sources but did not also exclude synthetic minor sources suggests that no exclusion was intended for synthetic minor sources. Indeed, nothing in the statute suggests that EPA should exclude a control technology from its consideration of the MACT floor because the technology is so effective that it reduces source emissions such that the source is no longer a major source of HAP. (See 67 FR 36,460 and 36,464, May 23, 2002, stating this rationale for including synthetic minor sources in the floor determination for the proposed NESHAP for municipal solid waste landfills.)

Some commenters argue that because the BSCP source category only includes major sources and synthetic minor sources are non-major by definition, synthetic minor sources (like true area sources) fall outside the regulated source category and should not be considered in MACT floor determinations. EPA agrees that the BSCP source category includes only major sources. (See 67 FR 47,894 and 47,898, July 22, 2002.) However, EPA disagrees that the CAA contemplates that synthetic minor sources must be treated like true area sources and excluded from MACT floor determinations. Section 112(a) of the CAA defines a major source as:

> any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit considering controls, in the aggregate, 10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants * * *.

(*See* CAA section 112(a)(1).) An area source is defined as any stationary source of hazardous air pollutants that is not a major source. (See CAA section 112(a)(1).) In the major source definition, the reference to a source's potential to emit considering controls allows the interpretation that a source's potential to emit before and after controls is relevant, such that synthetic minor sources may be considered within the meaning of this definition and included in MACT floor determinations for categories of major sources.[2] Some commenters appear to suggest that the reference to a source's potential to emit considering controls can only mean a source's potential to emit after controls have been implemented. While it is possible to read the phrase in this manner in isolation, this interpretation would have the effect of excluding the best-performing sources in a category from MACT floor determinations and therefore would be contrary to the statutory mandate that EPA set MACT floors based on the levels the best-controlled new sources and the best-performing existing sources achieve in practice. We believe the statutory reference to potential to emit considering controls should be read in a manner consistent with the other requirements of section 112(d) of the CAA to allow for the consideration of synthetic minor sources in MACT floor determinations for categories of major sources.

In addition, the legislative history suggests that synthetic minor sources should be included in MACT floor determinations. In a floor statement, Senator Durenberger stated that in implementing section 112(d)(3) of the CAA, "the [Senate] managers intend the Administrator to take whatever steps are necessary to assure that [the Administrator] has collected data on *all of the better-performing sources within each category.* [The Administrator] must have a data-gathering program sufficient to assure that [EPA] does not miss *any sources that have superior levels of emission control.*" (See Environment and Natural Resources Policy Division, Congressional Research Service, 103d Cong., S.Prt. 103–38 (prepared for the U.S. Senate Committee on Environment and Public Works), A Legislative History of the Clean Air Act Amendments of 1990 at 870, Nov. 1993, emphasis added.) This statement underscores that Congress intended for MACT floor determinations to reflect consideration of all of the sources in each category with the best emission controls. We believe it would be inconsistent with Congress's intent and the plain language of the CAA to exclude synthetic minor sources—those sources with superior controls which became synthetic minor sources by implementing such controls—from MACT floor determinations.

We believe that the inclusion of synthetic minor sources in MACT floor determinations is justified because of the reasons explained above. Even if the MACT floor determination had been "no emissions reductions" we believe that a departure from the MACT floor to a beyond-the-floor standard, based on DLA technology, is viable because the benefits associated with the emissions reductions will exceed the cost of installing and operating the technology.

2. MACT Floors for Existing Sources

Some commenters questioned how the MACT floor for existing sources was

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[1] If a category or subcategory has fewer than 30 sources, the floor shall be "the average emission limitation achieved by the *best performing* 5 sources (for which the Administrator has or could reasonably obtain emissions information) in the category or subcategory." (See CAA section 112(d)(3)(B), emphasis added.)

[2] We believe this approach is not inconsistent with our policy that existing sources that limit their potential to emit to below the major source threshold prior to the first compliance deadline under a MACT standard will not be subject to the standard, as one commenter suggests. (See Memorandum from John S. Seitz, Director, Office of Air Quality Planning and Standards, EPA, to EPA Regions, "Potential to Emit for MACT Standards—Guidance on Timing Issues," May 16, 1995.) Including synthetic minor sources in MACT floor determinations ensures that MACT floors reflect the best-performing sources, as the CAA requires. At the same time, our policy recognizes that sources that already achieve or perform better than the MACT floors need not be subject to the MACT standards.

set. Some commenters thought that control devices installed for sulfur oxides (SO_x) control (rather than for HAP control) should not be considered in the MACT floor. Other commenters felt that costs should be a consideration.

One commenter charged that EPA has simply set MACT floors based on control technology type and that EPA did not identify the relevant best performers and set floors reflecting their average emission level. The commenter noted that factors other than control device type affect emissions and that EPA must consider all non-negligible factors in setting MACT floors and considering beyond-the-floor measures. The commenter stated that if EPA believes it is unworkable to consider all factors, then perhaps EPA should base standards on actual emissions data which reflects all the factors influencing a source's performance. The commenter also noted that EPA picked the worst performance of any source that used the chosen technology to set the floor for PM.

A detailed discussion of how we determined the MACT floor for existing large tunnel kilns (*i.e.*, tunnel kilns with design capacities equal to or greater than 9.07 Mg/hr (10 tph)) is provided below. Although the discussion in the example below focuses on existing large tunnel kilns that exhaust directly to the atmosphere or to an APCD, the same MACT floor methodology was used for existing large tunnel kilns that exhaust to sawdust dryers prior to exhausting to the atmosphere, existing small tunnel kilns that exhaust directly to the atmosphere or to an APCD, existing small sawdust-fired tunnel kilns that duct to sawdust dryers, and existing periodic kilns. Details of these MACT floor determinations were discussed in the preamble to the proposed rule. (See 67 FR 47909–47912, July 22, 2002.) Section 112(d)(3) is the section of the CAA that dictates how we must establish MACT floors. Section 112(d)(3) of the CAA states that:

> The maximum degree of reduction in emissions that is deemed achievable for new sources in a category or subcategory shall not be less stringent than the emission control that is achieved in practice by the best controlled similar source, as determined by the Administrator. Emission standards promulgated under this subsection for existing sources in a category or subcategory may be less stringent than standards for new sources in the same category or subcategory but shall not be less stringent, and may be more stringent than—
>
> (A) Rhe average emission limitation achieved by the best performing 12 percent of the existing sources (for which the Administrator has emissions information), excluding those sources that have, within 18 months before the emission standard is proposed or within 30 months before such standard is promulgated, whichever is later, first achieved a level of emission rate or emission reduction which complies, or would comply if the source is not subject to such standard, with the lowest achievable emission rate (as defined by section 171) applicable to the source category and prevailing at the time, in the category or subcategory for categories and subcategories with 30 or more sources * * *.

With the exception of the LAER provisions in section 112(d)(3)(A) of the CAA, the CAA requires us to base the MACT floor on the best-performing sources without consideration of why facilities decided to control emissions. Therefore, if an APCD is reducing HAP emissions (*e.g.*, HF, HCl, or HAP metals), it is irrelevant if sources installed APCD for SO_X or visible emissions control for purposes of conducting MACT floor determinations.

We determined the MACT floor control level for existing sources using the following general procedure:

(1) We reviewed available data on pollution prevention techniques (including substitution of raw materials and/or fuels) and the performance of add-on control devices to determine the techniques that were viable for and effective at reducing HAP emissions;

(2) For each subcategory, we ranked the kilns from the best performing to the worst performing based on the emission reduction technique used on the kilns;

(3) For each subcategory, we then identified the 94th percentile kiln and the emission reduction technique that represented the MACT floor technology; and

(4) For each subcategory, we then selected production-based or percent-reduction emission limits that correspond to the 94th percentile kiln and emission reduction technique, and we based our selections on the available data while considering variability in the performance of a given emission reduction technique.

To identify the best-performing emission reduction techniques, we reviewed available data on pollution prevention techniques (*i.e.,*, substitution of raw materials and/or fuels) and the performance of add-on control devices. We determined that substitution of raw materials and/or fuels is not an option because substitution of raw materials and/or fuels could affect the ability of a facility to duplicate its current product line. In addition, it is impractical for facilities to import, from a distance of more than a few miles, the large amounts of raw material that are required (most facilities are located in close proximity to their raw material source). With respect to use of low-HAP fuels, our available test data for the BSCP industry do not show identifiable differences in emissions based on kiln fuel type; that is, the contribution of raw materials to HAP emissions far outweighs the contribution of the fuels. In addition, fuel type can impact the color of a product, and any requirement that would require a kiln to change fuel type could cause the kiln to be unable to match an existing product line. While we agree that factors other than APCD type can affect emissions, we do not have the data to determine the specific degree of the effect of factors other than APCD on emissions, and we believe that, for the BSCP industry, factors other than APCD use are not viable MACT floor or beyond-the-floor control options. Our data show that add-on APCD have a large effect on emissions, and further show that the presence or absence of an APCD is likely the greatest factor in determining a BSCP kiln's actual performance. It follows that the subset of BSCP kilns that are the best performers are those with add-on APCD. Therefore, our analysis focused on the performance of add-on control devices.

Prior to proposal we concluded that the best-performing add-on control devices were DIFF, DLS/FF, and WS. Based on the comments received following proposal (as discussed elsewhere in this preamble) regarding retrofit concerns with these technologies, we now believe that DLA are the only currently available technology that can be used to retrofit existing large kilns without potentially significant impacts on the production process. Thus, DLA are the best-performing APCD for existing large tunnel kilns.

We ranked the kilns within each subcategory according to APCD use. Information on the number of kilns and the types of APCD was based primarily on responses to a survey of the industry and additional information gathered following the survey including public comments on the proposed rule. Equipment in use at major sources and synthetic minor sources was used in the equipment ranking. In accordance with section 112(d)(3)(A) of the CAA, equipment at kilns that achieved LAER less than 18 months before proposal was not included in the equipment ranking. When we ranked the large tunnel kilns, we treated kilns equipped with DLA as the best-controlled sources, although DIFF, DLS/FF, and WS also can achieve the level of performance of a DLA. We ranked the kilns by APCD rather than actual unit-specific emissions reductions because we do not have emissions test data for all kilns.

Section 112(d)(3) of the CAA specifies that we set standards for existing sources that are no less stringent than the average emission limitation achieved by the best-performing 12 percent of existing sources (for which the Administrator has emissions information) where there are 30 or more sources in the category or subcategory. Our interpretation of average emission limitation is that it is a measure of central tendency, such as the arithmetic mean or the median. If the median is used when there are at least 30 sources, then the emission level achievable by the source and its APCD that is at the bottom of the top 6 percent of the best-performing sources (*i.e.*, the 94th percentile) represents the MACT floor control level. We based our MACT floors for each BSCP subcategory on this interpretation. Nineteen percent (22 of 115) of the existing large tunnel kilns located at synthetic minor sources or major sources are controlled by a DLA (12), DIFF (4), DLS/FF (4), or WS (2). Because more than 6 percent of the large tunnel kilns reduce emissions by some technique, emissions reductions from these kilns are required under the CAA. We then considered which of these controls are proven to be applicable to existing tunnel kilns, and we ranked these kilns to determine the appropriate MACT emission limits. We consider the 12 DLA to be equivalent and believe that this type of control can be applied to any existing large tunnel kiln without causing potentially significant production problems. We consider the performance of all of the DLA to be equivalent because there currently are two types of DLA in the industry (supplied by two manufacturers), and we have test data for both designs that show HF removal efficiencies that are within 1 percent of one another. We excluded DIFF and DLS/FF from our ranking of controls for existing sources because of the reported problems caused by applying DIFF and DLS/FF to existing kilns. We excluded WS from our ranking of controls for existing sources because many facilities do not have proven wastewater disposal options. Therefore, we only considered DLA in our ranking, and accordingly, the 94th percentile source (the 7th best-controlled source) is a DLA-controlled kiln. Therefore, the MACT floors for existing large tunnel kilns are based on the level of control achieved by a DLA. We have DLA outlet test data for 7 of the 12 existing large DLA-controlled tunnel kilns, and therefore, we are confident that our test data are within the best-controlled 6 percent of sources. Furthermore, the single best-performing source, based on our available DLA outlet data, is one of the three sources for which a control efficiency is available.

Section 112(d)(2) of the CAA dictates how we must establish MACT. The MACT can either be established at the MACT floor, or can be some control level more stringent than the MACT floor or beyond-the-floor. Section 112(d)(2) of the CAA states that:

> Emissions standards promulgated under this subsection and applicable to new or existing sources of hazardous air pollutants shall require the maximum degree of reduction in emissions of the hazardous air pollutants subject to this section (including a prohibition on such emissions, where achievable) that the Administrator, taking into consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements, determines is achievable for new or existing sources in the category or subcategory to which such emission standard applies * * *.

Although section 112(d)(3) of the CAA does not allow us to consider cost when determining MACT floors, we do consider costs when we examine beyond-the-floor control options according to section 112(d)(2) of the CAA. We acknowledge the commenters' concerns regarding the cost of the proposed standards. We determined that beyond-the-floor control measures would not be appropriate for existing large BSCP kilns because of retrofit costs arising from technical difficulties in retrofitting DIFF, DLS/FF, or WS. Thus, the emission limits for existing large tunnel kilns in today's final rule are based on the level of control achievable with a DLA.

It is our goal to set emission standards that reflect the performance of the best-controlled sources. Once we identified the subset of the best-controlled BSCP sources (*i.e.*, DLA-controlled kilns), we used the highest emission level associated with these best performers to set the emission standard because it was our intent to set emission limits that reflect the performance that the best-controlled sources continually achieve considering variability. All sources, including the best-controlled sources, have variability in emissions. For example, data (individual test runs) from two tests conducted on one DLA-controlled kiln showed HF control efficiencies that ranged from 91.6 percent to 96.4 percent. This variability may result from APCD performance, and also could result from uncertainty associated with the test methods. Commenters have agreed with our approach to setting the production-based emission limits at or slightly higher than the highest data point, because this approach accounts for variability in the performance of individual sources, variability that could exist across the industry, and uncertainty in the test methods used to measure emissions. Furthermore, use of the highest emission level associated with the best performers prevents sources within the best-controlled subset from having to remove their existing APCD and replace it with a new one that may or may not achieve slightly better performance.

We believe and intend that a well-operated DLA will achieve the emission limits set forth in this rulemaking. However, concerns have recently been raised that if high concentrations of sulfur exist in the kiln exhaust gas stream, the ability of a well-operated DLA to reduce the target acid gas HAP emissions (*i.e.,* HF and HCl) may be compromised. The data we have does not suggest that these concerns are justified. If the EPA receives information showing that they are, EPA will take prompt action to resolve the issue through rulemaking and ensure that a facility with a well-operated DLA will be in compliance with the rule. The EPA will also work with any affected facilities to ensure that they are not subject to inappropriate sanctions before we are able to complete such a rulemaking.

D. New Source MACT

Several commenters disagreed that a large (design capacity equal to or greater than 9.07 Mg/hr (10 tph) of fired product) tunnel kiln equipped with DIFF, DLS/FF or WS was the best-controlled similar source for all new tunnel kilns. The commenters expressed concern that the DIFF, DLS/FF or WS controls proposed for all new tunnel kilns have not been demonstrated on smaller kilns. The commenters argued that emissions from small (*e.g.,* less than 9.07 Mg/hr (10 tph)) and large tunnel kilns are different because the required airflow and pollutant loading is different. The commenters stated that controls such as DIFF, DLS/FF, or WS do not decrease in size or cost for kilns below 9.07 Mg/hr (10 tph) design capacity. The commenters thought that the proposed standards for new tunnel kilns would prevent future construction of and upgrades to smaller kilns. The commenters recommended that a throughput cutoff be provided for new and reconstructed kilns. One commenter suggested that EPA create a size-cutoff for new kilns, where the best-controlled similar source for smaller new kilns is a DLA-controlled kiln, and DLS/FF, DIFF, or WS for the larger kilns. One commenter noted the potential of existing kilns triggering new source requirements during reconstruction. The commenter requested that the ability of small businesses to overhaul existing kilns be addressed in the final rule.

These commenters have addressed several related issues including the selection of the best-controlled similar source, differences between small and large tunnel kilns, the feasibility of the proposed MACT-level controls in controlling emissions from smaller tunnel kilns or reconstructed tunnel kilns, and the costs of new controls. In responding to these comments, we have re-evaluated our analysis of MACT for new and reconstructed tunnel kilns. In the original MACT analysis developed for the proposed rule, we recognized the inherent differences between small and large tunnel kilns and established a subcategorization level of 9.07 Mg/hr (10 tph). The proposed 9.07 Mg/hr (10 tph) subcategorization level applied to both existing and new tunnel kilns. For new and reconstructed sources, we selected the best-controlled similar source (DIFF, DLS/FF, WS) that would be applied to all new sources regardless of size. In re-evaluating this analysis and in light of several comments that described the inherent differences and issues with the application of DIFF, DLS/FF, and WS control technologies to small tunnel kilns or reconstructed tunnel kilns, we have revised MACT for new sources. We also have added language in 40 CFR 63.8390(i) to provide that it is not technologically and economically feasible for two types of existing kilns that would otherwise meet the criteria for reconstruction under 40 CFR 63.2 to meet the relevant standards—*i.e.*, new source MACT—and that such kilns do not fall within the definition of reconstruction and are not subject to new source MACT requirements. The two types of kilns are existing small kilns that are rebuilt such that they become large kilns and existing large DLA-controlled tunnel kilns that are rebuilt. Today's final emission limits for those kilns and for new and reconstructed small tunnel kilns are based on the performance of DLA control technology. The final emission limits for new large tunnel kilns are based on the performance of DIFF, DLS/FF, and WS control technology. In addition, existing large tunnel kilns equipped with DIFF, DLS/FF or WS are reconstructed sources subject to new source MACT requirements if they meet the criteria for reconstruction in 40 CFR 63.2. Such kilns must continue to meet new source MACT limits, which are based on the performance of DIFF, DLS/FF, and WS.

We agree with the commenters that DIFF, DLS/FF, and WS control technologies have not been demonstrated on small kilns. However, we believe that the 9.07 Mg/hr (10 tph) size represents the threshold where emission control using DIFF, DLS/FF, or WS is technically feasible and demonstrated. Smaller kilns have smaller airflow rates than larger kilns and any fluctuations in airflow rates can have a significant impact on the ability of DIFF, DLS/FF, or WS to operate correctly. For new and reconstructed small kilns, the DLA control technology has been demonstrated to perform adequately despite the lower airflow rates; DLA control systems are not as sensitive to airflow changes as DIFF, DLS/FF, or WS control systems. In addition, existing small kilns that are rebuilt such that they become large kilns and existing large DLA-controlled kilns that are rebuilt would experience the same types of retrofit problems that we described for existing tunnel kilns, and we believe that such tunnel kilns should be subject to requirements that can be met with a DLA. The DIFF, DLS/FF, and WS control systems have been demonstrated on new large kilns. Therefore, MACT for new and reconstructed large tunnel kilns is based on DIFF, DLS/FF, and WS control and is unchanged from proposal. Finally, the determination of MACT for new sources at the floor does not take the cost of control into consideration.

Our revised standards for new and reconstructed small tunnel kilns, existing small kilns that are rebuilt such that they become large kilns, and existing large DLA-controlled kilns that are rebuilt are based on the use of a DLA, which is considerably less expensive than the other MACT controls. The revised standards should minimize the commenters' concerns over the costs of reconstructing older kilns.

E. Cost and Economic Impacts

Numerous comments were received regarding costs of the proposed rule. Commenters contended that EPA did not consider the full costs of the rule (*e.g.*, costs associated with problems retrofitting existing kilns). In general, commenters indicated that the economic impacts to brick industry would be severe. Several commenters pointed out that the brick industry is losing market share to cheaper building materials (*e.g.*, vinyl) that are more detrimental to the environment. The commenters stated that the proposed rule would have a negative effect on the future of many small businesses and the communities where they are located. The commenters expressed concern that the proposed rule would limit the opportunity for continued operation or expansion of brick plants throughout the U.S. The commenters noted that increased production costs would increase brick prices, causing brick to become less competitive with other materials and brick imports to rise, putting small U.S. companies out of business. Several commenters stated that the costs of the rule as proposed would prevent their company from ever replacing, performing a major repair on, or upgrading their existing kiln. Some commenters stated that the rule as proposed would eventually cause their company to go out of business. Some commenters added that they live in an economically depressed area and other jobs are not readily available.

One commenter disagreed with the Administrator's certification that the proposed rule would not create a significant impact on a substantial number of small entities. The commenter submitted an Economic Impacts Analysis (EIA). The commenter calculated and presented the Sales Test, Cash Flow Test, and Profit Test criteria which the commenter believes shows a greater number of small businesses at risk than does EPA's EIA. In addition, the commenter provided several specific comments on EPA's EIA. The commenter argued that the rule as proposed is a significant rulemaking per Executive Order (E.O.) 12866. A few commenters provided specific comments on the monitoring, reporting, and recordkeeping costs in the Office of Management and Budget (OMB) 83–I form and supporting statement.

Commenters also questioned the environmental benefits of the BSCP rule as proposed. One commenter questioned why the BSCP rule is necessary if brick manufacturing emissions are not causing public health problems or adverse environmental effects. Another commenter argued that there is no epidemiological evidence that anyone in North America has been harmed by brick plant HF emissions and that cancer incidence in brick plant workers is not higher than for the general population.

As previously mentioned in this preamble, section 112(b) of the CAA contains a list of HAP identified by Congress and authorizes EPA to add to that list pollutants that present or may present a threat of adverse effects to human health or the environment. Section 112(c) of the CAA requires us to list all categories and subcategories of major and area sources of HAP and to establish NESHAP for the listed source categories and subcategories under section 112(d) of the CAA. Because BSCP manufacturing is a listed source category containing major sources of HAP, we are required by the CAA to establish NESHAP for BSCP manufacturing.

As stated previously, MACT can either be established at the MACT floor, or can be some control level more stringent than the MACT floor or beyond the floor. Section 112(d)(3) of the CAA does not allow us to consider cost when determining MACT floors. We are only allowed to consider costs when we examine beyond-the-floor control options according to section 112(d)(2) of the CAA. We acknowledge the commenters' concerns regarding the cost of the proposed rule. At proposal, we determined that beyond-the-floor control measures would not be appropriate for the BSCP industry, in part because of costs.

Following proposal, we reevaluated the MACT floors for existing tunnel kilns and have revised the standards to incorporate use of DLA on existing large tunnel kilns. We also revised the MACT standards for new and reconstructed small tunnel kilns, existing small kilns that are rebuilt such that they become large kilns, and existing large DLA-controlled tunnel kilns that are rebuilt such that the standards are based on the level of performance that can be achieved by a DLA. (MACT requirements for existing small tunnel kilns and new and reconstructed large tunnel kilns remain unchanged.) We continue to agree that beyond-the-floor control measures are not warranted for the BSCP industry. The revised MACT standards for new and reconstructed small tunnel kilns, existing small kilns that are rebuilt such that they become large kilns, and existing large DLA-controlled kilns that are rebuilt are the same as the revised standards for existing large tunnel kilns. These revised standards are less costly and should reduce concerns regarding cost of retrofitting or rebuilding existing kilns and starting up new small kilns. Environmental benefits of today's final BSCP rule are discussed later in this preamble.

EPA reviewed the economic impact analysis report submitted by the commenter. We have revised our EIA to identify additional small businesses affected by the rule. We have also incorporated the lower revised cost estimates into the EIA. Impacts on small businesses are considerably lower in the revised analysis and prices are predicted to rise by less than one percent on average. The results of our revised EIA, as well as a discussion of the impact of today's final rule on small businesses, are presented later in this preamble.

Comments on the costs of monitoring, reporting, and recordkeeping were incorporated into the revised OMB 83–I form and supporting statement as appropriate. A discussion of the OMB 83–I form and supporting statement prepared in compliance with the Paperwork Reduction Act is presented later in this preamble.

F. Test Data and Emission Limits

1. HF and HCl Emission Limits

Commenters stated that the test data EPA used to set the HF and HCl limits are questionable. An independent consultant, hired by the BSCP industry, reviewed the data and determined that six of the seven test runs used the wrong filter media. A glass filter media was used instead of a Teflon filter. The commenter suggested that, as a result, the data could be biased. One commenter also charged that EPA removed high test runs without any technical basis even though all of these runs met the same quality control (QC) criteria as other runs. Finally, one commenter stated that EPA's use of both HF and total fluorides (TF) data to develop the average uncontrolled HF emission factor (which was used in developing the HF emission limit) was unsupported, and the commenter believes that EPA should use only the HF test data because HF is the regulated pollutant.

We have reviewed the emission tests mentioned by the commenter and agree that there are some problems with most of the available test data, and we have accounted for any potential bias by revising the emission limits. In consultation with EPA's Emission Measurement Center (EMC), we used a conservative approach to determine the possible impact of the bias on the percent reduction emission limits. The analysis showed that our available percent reduction data could be as much as about 5 percent high, and we, therefore, decreased the corresponding HF and HCl percent reduction requirements by 5 percent and adjusted the corresponding production-based emission limits accordingly. In response to the commenter's assertion that we dropped two test runs without a technical reason, we examined the test runs in question and incorporated one of the two runs back into the data set used for developing the standards. Finally, in response to the appropriateness of using TF data in calculating the average HF emission factor, while the average of the TF and HF data sets suggest that TF and HF measurements are similar, we recognize the inconsistencies between the few available side-by-side HF and TF tests and we, therefore, decided to remove the TF data from the HF emission factor calculation. Based on the three issues discussed above, we revised the emission limits for kilns where MACT is based on use of DIFF, DLS/FF, or WS (*i.e.*, for new large kilns). Today's final rule requires new large kilns to limit HF emissions to 0.029 kilograms per megagram (kg/Mg) (0.057 pounds per ton (lb/ton)) of fired product or reduce HF emissions by 90 percent; and limit HCl emissions to 0.028 kg/Mg (0.056 lb/ton) or reduce HCl emissions by 85 percent.

The revised HF and HCl emission limits for existing large tunnel kilns, new and reconstructed small tunnel kilns, existing small kilns that are rebuilt such that they become large kilns, and existing large DLA-controlled tunnel kilns that are rebuilt are based on the use of a DLA for HAP reduction. Two HF emission tests (both conducted on the same source) and two total fluorides emission test are available for DLA-controlled kilns, and the tests showed HF or TF control efficiencies of 92.3 percent (HF), 96.4 percent (HF), 93.3 percent (TF), and 93.5 percent (TF). Similar to the DIFF and DLS/FF tests, we identified problems with the two HF emission tests that could have biased the control efficiencies high. To account for this uncertain bias, and considering typical vendor guarantees for DLA systems (vendors will guarantee 90 percent HF reduction unless a lesser percentage meets the customer's need, in which case the vendors typically provide lower guarantees), we selected a percent reduction emission limit of 90 percent for HF. We applied this 90 percent reduction to the revised average HF emission factor of 0.29 kg/Mg (0.57 lb/ton) to calculate a production-based HF emission limit of 0.029 kg/Mg (0.057 lb/ton). Control efficiency data for HCl are available from two tests on a single DLA-controlled kiln. The tests averaged 30.7 percent control, and we selected a percent reduction HCl emission limit of 30 percent. We applied this 30 percent reduction to the average HCl emission factor of 0.19 kg/Mg (0.37 lb/ton) to calculate a production-based HCl emission limit of 0.13 kg/Mg (0.26 lb/ton).

Percent of HAP metals in PM. Several commenters noted that HAP metals and PM data from four facilities (0.16 percent, 0.99 percent, 2.8 percent, and 4.5 percent) were used to arrive at 1.9 percent of the PM is PM HAP. The commenters stated that EPA included an invalid, high data point for manganese in developing the percentage of PM that is PM HAP. We have examined the test run mentioned by the commenters and agree that the run should be voided. Our revised analyses now indicate that the overall percentage of PM that is HAP metals is 0.72 percent.

PM limit. Other commenters argued that a PM limit for brick kilns is unnecessary. One commenter noted that metals occur naturally in clays or shales used to make bricks and that PM emissions from BSCP plants are clay dust. The commenter argued that metals are locked into the structure of the clay dust and are not bio-available to affect humans through respiratory adsorption, ingestion, or dermal contact. Some commenters noted that there is limited information on the amount of HAP metals in the PM emitted. Commenters pointed out that EPA is not setting a PM limit for clay refractory kilns. Some commenters disagreed that PM is an adequate surrogate for HAP metals emissions. Commenters also requested that a percent reduction alternative be allowed for the PM standard, similar to the percent reduction limits for HF and HCl.

We agree that PM emitted from BSCP facilities is largely clay dust, and that metals are naturally occurring in clays and shales used to make bricks. Many BSCP facilities apply surface coatings or body additives containing HAP metals to their products, and these coatings are another potential source of HAP metals emissions. These types of additives and coatings are not used in the manufacture of clay refractories.

We have four emission tests for HAP metals from tunnel kilns and all of these tests measured some level of HAP metals emissions including emissions of antimony, arsenic, beryllium, cadmium, chromium, cobalt, mercury, manganese, nickel, lead, and selenium. Based on these data, we believe that all kilns emit some level of HAP metals and, therefore, we are regulating HAP metals emissions. Test data for HAP metals are not available for clay refractories kilns.

We are unaware of any information to support the idea that the HAP metals are locked into the structure of the clay and are not bio-available to affect humans. In the absence of such information and in the interest of protecting public health, we assume conservatively that the HAP metals are bio-available and could affect human health. This assumption is consistent with the conservative approach embodied in the CAA section 112(b)(2) directive that EPA add pollutants to the statutory list of HAP that ‘‘may’’ present adverse risks to human health and the environment through various exposure routes.

We used PM as a surrogate for HAP metals so that individual emission limits would not be based on the limited and variable data. We examined the available HAP metals test data and calculated that about 95 percent of the HAP metals emissions are in particulate form. Furthermore, the types of control technologies used on BSCP kilns remove PM and would indiscriminately remove particulate HAP metals. The United States Court of Appeals for the District of Columbia Circuit stated in a December 15, 2000 decision (in response to the National Lime Association (NLA) challenge of the use of PM as a surrogate for HAP metals), ‘‘if HAP metals are invariably present in cement kiln PM, then even if the ratio of metals to PM is small and variable, or simply unknown, PM is a reasonable surrogate for the metals—assuming * * * that PM control technology indiscriminately captures HAP metals along with other particulates.’’ Our use of PM as a surrogate for HAP metals in the final BSCP rule is consistent with this decision.

We typically do not include percent reduction as an alternative for PM because a percent reduction standard rewards those facilities that have high inlet PM loadings. We believe that this is different from the percent reduction standards for HF and HCl because facilities do not typically have options for reducing the uncontrolled levels of HF or HCl. Therefore, we are not providing an alternative percent reduction standard for PM.

The revised PM emission limit for existing large tunnel kilns, new and reconstructed small tunnel kilns, existing small kilns that are rebuilt such that they become large kilns, and existing large DLA-controlled tunnel kilns that are rebuilt is based on the use of a DLA. Data from four tests conducted at the outlets of DLA were available for establishing a production-based emission limit, and we selected the highest PM data point as the emission limit in order to account for variability. Today’s final rule contains a PM emission limit of 0.21 kg/Mg (0.42 lb/ton) of fired product for existing large tunnel kilns, new and reconstructed small tunnel kilns, existing small kilns that are rebuilt such that they become large kilns, and existing large DLA-controlled tunnel kilns that are rebuilt. The PM emission limit for new and reconstructed large tunnel kilns is unchanged from proposal (0.060 kg/Mg (0.12 lb/ton) of fired product).

G. Monitoring Requirements

Numerous comments were received on the proposed monitoring requirements. Some commenters felt that the monitoring, reporting, and recordkeeping requirements were unreasonable. Commenters noted that the monitoring requirements would require additional and higher skilled personnel.

Under section 114(a)(3) of the CAA, owners or operators of major sources are required to conduct enhanced monitoring of affected sources to ensure compliance with applicable emission standards. In response to this mandate, we have incorporated continuous compliance requirements into all part 63 standards, generally in the form of continuous emissions monitoring or continuous parameter monitoring. We believe that continuous monitoring is needed to ensure that emission controls are operated properly. However, 40 CFR 63.8(f) allows owners and operators of affected sources to request approval for alternative monitoring procedures to demonstrate compliance with emission limitations.

Although we have eliminated some of the proposed monitoring requirements (such as fabric filter inlet temperature monitoring) from today’s final rule, we have retained most of the proposed monitoring requirements. We believe that those monitoring requirements are the minimum needed to ensure continuous compliance with the emission limits.

1. Operation, Maintenance, and Monitoring (OM&M) Plan

Some commenters felt that development of an OM&M plan was overly burdensome. One commenter thought the requirement to include OM&M procedures for kiln operation was unjustified. Another commenter noted possible contradictions of OM&M plan requirements and Table 7 of the proposed BSCP rule (the table showing applicability of the General Provisions to part 63).

After reviewing these comments, we decided that OM&M plans do not have to include procedures for monitoring the operation and maintenance of tunnel kilns, and we have written the final rule accordingly. However, we continue to believe that site-specific OM&M plans are necessary to ensure continued proper operation of any control device that is used to comply with the final rule.

Regarding the apparent contradictions between 40 CFR 63.8425(b)(8) through (10) and Table 7 of the proposed rule, we did not cite the General Provisions to part A in the proposed 40 CFR 63.8425 (b)(8) through (10), but specified that OM&M plans must include operation and maintenance, quality assurance, and reporting and recordkeeping procedures that are consistent with the General Provisions. Therefore, we believe there is no contradiction between 40 CFR 63.8425 (b)(8) through (10) and Table 7 of the proposed rule. However, we did clarify in Table 7 of the final rule that 40 CFR 63.8(c)(4) does not apply to subpart JJJJJ because 40 CFR 63.8425 and 63.8465 specify the requirements for continuous monitoring systems (CMS).

Some commenters requested clarification on whether OM&M plans (and startup, shutdown, and malfunction plans (SSMP)) are required for kilns that would not be subject to control requirements (*e.g.*, existing small tunnel kilns). Another commenter questioned if an OM&M plan would be required if compliance is achieved without a control device. The BSCP NESHAP applies only to affected sources. Under today's final rule, an existing small tunnel kiln is not an affected source. Therefore, the requirements for OM&M plans, SSMP, and other monitoring, notification, reporting, and recordkeeping requirements do not apply to those kilns. Owners or operators will be required to prepare an OM&M plan and SSMP for any kiln that is an affected source even if the kiln can meet the emission limits without the use of a control device.

2. Bag Leak Detectors

Commenters indicated that bag leak detectors are unnecessary, overly protective, and maintenance intensive. The commenters noted that bag failure is noticeable because PM emissions would be visible at the stack. Several commenters requested that opacity or visible emissions (VE) determinations be allowed as opposed to bag leak detectors.

We agree with the commenters that periodic VE checks should provide a reasonable alternative to bag leak detectors, and we have written the final rule accordingly. In today's final rule, owners and operators of affected kilns that are controlled with a DLS/FF or DIFF can choose between installing a bag leak detection system or performing daily VE checks. Today's final rule also includes a provision for decreasing the frequency of VE checks provided no VE are observed.

3. Water Injection Rate Monitoring on DLS/FF

Three commenters stated that DLS/FF water injection rate monitoring has nothing to do with HF or HCl removal (but is important for sulfur dioxide (SO_2) removal) and recommended that the provision for monitoring DLS/FF water injection rate be eliminated.

After reviewing the available information, we decided to eliminate the requirement for water injection rate monitoring on affected DLS/FF-controlled kilns. Water injection is used to enhance the removal of SO_2 by a DLS/FF, but has little effect on removal of HF and HCl.

4. Fabric Filter Inlet Temperature

Several commenters recommended that the requirement to monitor fabric filter inlet temperature be eliminated from the rule as proposed. The commenters explained that it would be impractical to hold the fabric filter inlet temperature to within 25 degrees below the average established during the performance test. The fabric filter inlet temperature varies frequently, much more than 25 degrees, because of many process factors. Other commenters noted that fabric filter inlet temperature has little relevancy to acid gas control. One commenter stated that control systems using hydrated lime are generally known to have increased HCl and HF removal when temperatures increase.

As a result of these comments, we have eliminated the requirement for monitoring fabric filter inlet temperatures on affected kilns that are controlled with a DLS/FF or DIFF. We believe that the other monitoring requirements (*e.g.*, lime feed rate monitoring and periodic VE checks) that we have incorporated into the final rule are adequate for ensuring continuous compliance with the emission limits.

5. DLA Parameter Monitoring

Many commenters suggested potential parametric monitoring requirements for DLA that could be used to demonstrate continuous compliance. Various commenters suggested documenting use, on a continuous basis, of the same limestone that was used during the performance test demonstrating compliance. Other suggestions included monitoring pressure drop (demonstrating airflow); limestone flow; and inlet and/or exhaust gas temperature.

We have incorporated parameter monitoring requirements for DLA into the final rule based on information provided by commenters and a recent site visit to a facility operating a DLA. Today's final rule will require owners and operators of affected kilns with DLA to continuously monitor the pressure drop across the DLA; perform a daily visual check of the limestone hopper and storage bin (located at the top of the DLA), and record the limestone feeder setting daily; and perform periodic VE observations. In addition, owners and operators will be required to document the source of the limestone used during the most recent performance test and maintain records that demonstrate that the source of limestone has not changed.

6. Continuous Emission Monitoring Systems

In the preamble to the proposed rule, we requested comment on requiring the application of PM continuous emission monitoring systems (CEMS) as a method to assure continuous compliance with the proposed PM emission limits for BSCP tunnel kilns. While we believe there is evidence that PM CEMS should work on BSCP tunnel kilns, we received no comments in support of requiring PM CEMS. Commenters opposed use of CEMS when less expensive, but effective, parametric monitoring alternatives are available. Therefore, today's final rule does not require use of PM CEMS or any other type of CEMS. We believe that the parameter monitoring requirements specified in the final rule are adequate for ensuring continuous compliance.

7. Establishing/Re-Establishing Production Rate

Several commenters requested that the process weight threshold be based on average annual throughput instead of hourly or monthly throughput. One commenter pointed out that the nature of brick production does not allow for spikes in emissions. Several commenters stated that the averaging period used to determine the MACT floor applicability to existing tunnel kilns must have the same production averaging basis as the data used in setting the subcategorization level. The commenters stated that it is not reasonable to base the standard on a 12-month averaging period and then enforce the floor on an instantaneous or 30-day rolling averaging period.

One commenter requested clarification as to whether EPA would require a retest if the maximum production level of a kiln would be higher than the level observed during the performance test. The commenter added that several States recognize that capacity and maximum production are difficult figures to calculate for a brick kiln because they are highly dependent on the specific characteristics of a product (size, percent void).

We agree with the commenters that a kiln's process weight threshold (*e.g.*, design capacity level) should be based on average annual tonnage rather than on the proposed 30-day rolling average. We have revised the final BSCP rule accordingly to require the ton per hour production capacity of a kiln to be calculated based on the maximum amount of BSCP (in tons) that can be produced in a 12-month period divided by 8,760 hours per year.

Regarding the question of whether we will require a retest if the maximum production level of a kiln is higher than the level observed during the performance test, a retest will be required because an increase in production is likely to increase emissions, and the operating limits that are based on the performance test would no longer demonstrate continuous compliance with the emission limits.

8. Test Methods

One commenter requested that we allow any of the applicable EPA Method 5 variations to demonstrate compliance with the PM standard. The commenter pointed out that a facility with high SO_2 could reduce the potential for SO_2 to be counted as PM by using EPA Method 5B. We are not including EPA Method 5B as a test method because our emission limit is based on EPA Method 5 and includes tests on sources with high SO_2 emissions. Individual facilities will have the option of requesting an alternative test method.

One commenter on the proposed clay ceramics rule requested that the final rule provide facilities with the option to use either EPA Method 26A or EPA Method 320 for all required stack testing for HF and HCl. This comment applies for both BSCP and clay ceramics. Therefore, we have modified today's final BSCP rule to include EPA Method 320 as an alternative to EPA Method 26A.

H. Startup, Shutdown, and Malfunction

1. APCD Bypass

Several commenters stated that the BSCP rule, as proposed, would not allow the kiln control device to be bypassed at any time. Various commenters stated that the proposed MACT controls (DIFF, DLS/FF, or WS) must maintain a given flow to perform efficiently. Thus, the APCD would dictate how the kiln is operated. During initial kiln startup or subsequent kiln startups or shutdowns, airflow temperatures and volumes would be below APCD design volumes. The heat from the furnace zone could damage the kiln walls and cars if not vented. Therefore, the ability to bypass during startups, routine maintenance, and emergency shutdowns of the APCD is needed.

Several commenters noted that brick kilns are constant flow devices that cannot just be turned off without detrimental impact to large volumes of product (*e.g.*, character, color, and quality of brick) and the kiln itself. The commenters stated that days to weeks may be needed to properly shut down a brick kiln. One commenter noted that kilns operate continuously 2 to 3 years before being shut down for routine maintenance.

Commenters stated that short periods of bypass are necessary to conduct routine preventive maintenance inspections of APCD. Commenters pointed out that the control devices currently employed have and use bypass capability for routine maintenance and emergency repairs.

We generally agree with the commenters that some provision is needed to allow the control device on tunnel kilns to be bypassed for routine maintenance of the control device, and we have revised the rule accordingly. Under 40 CFR 63.8420(e) of today's final rule, owners and operators of an affected tunnel kiln can bypass the kiln control device for a cumulative period of up to 4 percent of the annual operating hours for the kiln. Based on the data and other information submitted by commenters on the proposed rule, we believe that the amount of time equating to 4 percent of annual kiln operating hours is adequate for completing routine maintenance on the types of controls that are likely to be used to comply with the BSCP NESHAP.

To comply with this bypass provision, owners or operators must submit a request to us for a routine control device maintenance exemption. The request must justify the need for the routine maintenance on the control device and the time required to complete the maintenance activities. The request also must describe the maintenance activities and the frequency of the maintenance activities, explain why the maintenance cannot be accomplished during kiln shutdowns, and describe how emissions will be minimized during the period when the kiln is operating and the control device is offline. Upon approval, the request for exemption must be incorporated by reference in, and attached to, the affected source's title V permit. During any period when the kiln is operating and the kiln control device is offline, the owner or operator must minimize HAP emissions. The duration of such periods also must be minimized.

We also note that the bypass provision included in today's final rule does not apply to startups, shutdowns, or malfunctions. 40 CFR 63.6(f)(1) explicitly states that nonopacity emission standards, such as the proposed emission limits for HF, HCl, and PM, ''* * * apply at all times except during periods of startup, shutdown, and malfunction * * *'' Startups, shutdowns, and malfunctions must be addressed in a facility's SSMP.

2. Initial Startup

Commenters stated that it is impractical to meet emission standards during initial startup of a tunnel kiln. The commenters indicated that it can take from weeks to a year to bring new BSCP kilns online. In addition, APCD such as DIFF, DLS/FF, or WS cannot be brought online until adequate temperature and airflow ranges are met. The commenters indicated that roughly 75 percent of design gas flow rate or kiln production rate must be obtained before a DIFF or DLS/FF could begin to operate properly. Another commenter stated that the proposed initial testing deadline (180 days following the compliance date) would not provide enough time for a new kiln to come up-to-speed.

We recognize that an extended period of time may be needed for the initial startup of a new kiln and have added a definition of initial startup to the BSCP final rule to address the concerns expressed by the commenters. The definition differentiates between DLA-controlled kilns and DIFF-, DLS/FF-, or WS-controlled kilns, because DLA are not sensitive to airflow and only require that the kiln gases are hot enough to avoid condensation in the DLA. Avoiding condensation is necessary because water and calcium carbonate (limestone) combine to make cement, and any introduction of water in the DLA reaction chamber could cause the limestone to be cemented together. In the final rule, we provided the following definition: ''Initial startup'' means: (1) For a new or reconstructed tunnel kiln controlled with a DLA, and for a tunnel kiln that would be considered reconstructed but for 40 CFR 63.8390(i)(1) or 40 CFR 63.8390(i)(2), the time at which the temperature in the kiln first reaches 260 °C (500 °F) and the kiln contains product; or (2) for a new or reconstructed tunnel kiln controlled with a DIFF, DLS/FF, or WS, the time at which the kiln first reaches a level of production that is equal to 75 percent of the kiln design capacity or 12 months after the affected source begins firing BSCP, whichever is earlier. Although some commenters suggested that initial startup for DIFF-, DLS/FF-, and WS-controlled kilns be defined in terms of airflow, we defined initial startup in terms of production rate for DIFF-, DLS/FF-, and WS-controlled kilns because the final rule requires owners and operators of affected sources to monitor production rate, whereas flowrate monitoring is not required under today's final rule. We included the stipulation for DIFF-, DLS/FF-, and WS-controlled kilns that initial startup occurs no later than 12 months after the new kiln begins firing BSCP to prevent facilities from operating an affected new or reconstructed kiln at just less than 75 percent of the kiln design capacity long term to circumvent the final rule. A similar stipulation is not necessary for DLA-controlled kilns because the kiln temperature requirement is such that the kiln cannot produce BSCP until well after the temperature is reached.

By defining initial startup in today's final rule, we also have clarified the compliance date for new and reconstructed sources, which is specified in terms of the initial startup. Thus, new and reconstructed DIFF-, DLS/FF-, and WS-controlled tunnel kilns beginning operation after the promulgation date will be allowed to reach 75 percent of the kiln design capacity before initial startup is triggered and the APCD must come online. New and reconstructed DLA-controlled tunnel kilns, and tunnel kilns that would be considered reconstructed but for 40 CFR 63.8390(i)(1) or 40 CFR 63.8390(i)(2), beginning operation after the promulgation date will trigger initial startup when the temperature in the kiln first reaches 260°C (500°F) and the kiln contains product. Performance testing is required 180 days following the compliance date (*i.e.*, 180 days following initial startup). Facilities wishing to conduct performance testing to determine the level of air pollution control necessary may conduct such testing prior to achieving initial startup.

3. Startup

Two commenters expressed concern with how startup is defined with respect to the proposed rule. The commenters stated that, under the proposed rule, a kiln could be considered to be operating if only one burner was operating. However, a kiln could have as many as 100 burners or more. To clarify what constitutes kiln startup we added to today's final rule a definition of ''startup'' that incorporates ''starting the production process.''

4. Deviations

One commenter felt that the requirement of reporting emissions as deviations during startup, shutdown, or malfunction (SSM) is inappropriate because facilities are not required to be in compliance with the emission limitations during SSM. Another commenter requested that EPA make it clear the deviations are not necessarily an indication of noncompliance or excess emissions.

The term deviation applies to events during which an affected source fails to meet an emission limitation or comply with another requirement of the final rule. Deviations are not synonymous with violations; depending on the circumstances, a deviation may or may not be a violation of an applicable requirement. We agree with the commenter that an affected source need not be in compliance with emission limits during periods of SSM. Although we consider non-compliance with emission limits during startup, shutdown, and malfunction to be deviations from the emission limits, we do not consider these deviations to be violations of the emission limits. 40 CFR 63.7(e)(1) specifies that, ''Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test, nor shall emissions in excess of the level of the relevant standard during periods of startup, shutdown, and malfunction be considered a violation of the relevant standard unless otherwise specified in the relevant standard or a determination of noncompliance is made under 40 CFR 63.6(e).'' As indicated in Table 7 of the final rule, this language of the general provisions to part 63 does apply to subpart JJJJJ. The definition of deviation included in today's final rule is consistent with how deviation is defined in other NESHAP, and has not been changed since proposal.

I. Risk-Based Approaches

The preamble to the proposed BSCP rule requested comment on whether there might be further ways to structure the BSCP rule to focus on the facilities which pose significant risks and avoid the imposition of high costs on facilities that pose little risk to public health and the environment. Specifically, we requested comment on the technical and legal viability of two risk-based approaches: (1) An applicability cutoff for threshold pollutants under the authority of CAA section 112(d)(4); and (2) subcategorization and delisting under the authority of CAA sections 112(c)(1) and 112(c)(9).[3] We indicated that we would evaluate all comments before determining whether either approach would be included in the final BSCP rule. Numerous commenters submitted detailed comments on these risk-based approaches. These comments are summarized in the BSCP Response-to-Comments document (see SUPPLEMENTARY INFORMATION section).

Based on our consideration of the comments received and other factors, we have decided not to include the risk-based approaches in today's final BSCP rule. The risk-based approaches described in the proposed BSCP rule and addressed in the comments we received raise a number of complex issues. In addition, we are under time pressure to complete the BSCP rule, because the statutory deadline for promulgation has passed and a deadline suit has been filed against EPA. (See Sierra Club v. Whitman, Civil Action No. 1:01CV01537 (D.D.C.).) Given the range of issues raised by the risk-based approaches and the need to promulgate a final rule expeditiously, we believe that it is appropriate not to include any risk-based approaches in today's final BSCP rule. Nonetheless, we expect to continue to consider risk-based approaches in connection with other proposed NESHAP where we have described and solicited comment on such approaches. Finally, while we are not including risk-based approaches in today's final BSCP rule, we have included a number of other measures that we expect will reduce the costs and burdens on the affected sources.

III. Summary of the Final Brick and Structural Clay Products Manufacturing NESHAP

A. What Source Category Is Regulated by the Final Rule?

Today's final rule for BSCP manufacturing applies to BSCP manufacturing facilities that are, are located at, or are part of, a major source of HAP emissions. The BSCP manufacturing source category includes those facilities that manufacture brick (including, but not limited to, face brick, structural brick, and brick pavers); clay pipe; roof tile; extruded floor and wall tile; and/or other extruded, dimensional clay products. Brick and structural clay products primarily are produced from common clay and shale. Production of BSCP typically consists of processing and handling the raw materials, forming

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[3] See 68 FR 1276 (January 9, 2003) (Plywood and Composite Wood Products Proposed NESHAP) and docket number A–98–44, Item No. II–D–525 (White papers submitted to EPA outlining the risk-based approaches).

and cutting bricks and shapes, and drying and firing the bricks and shapes. One by-product of brick manufacturing is crushed brick, which is produced at some facilities by crushing reject bricks.

There are a total of 189 domestic BSCP manufacturing facilities; 170 of these facilities primarily produce brick, and 19 of these facilities primarily produce structural clay products. The 189 BSCP manufacturing facilities are located in 39 States and are owned by 89 companies. Seventy-six of the companies are small businesses, and these 76 companies own 92 of the BSCP manufacturing facilities. Thirteen of the companies are large businesses, and these 13 companies own 97 BSCP manufacturing facilities.

All BSCP are fired either in continuous (tunnel or roller) or batch (periodic) kilns. Because the vast majority of continuous kilns are tunnel kilns, continuous kilns, including roller kilns, will be referred to as tunnel kilns for the remainder of this preamble. A total of 314 permitted and operable tunnel kilns were reported by industry; 302 of these kilns are located at facilities that are estimated, based on uncontrolled emissions, to be major sources. Of the 302 tunnel kilns located at major sources, 275 are located at brick manufacturing facilities and 27 are located at structural clay products manufacturing facilities. A total of 227 permitted and operable periodic kilns were reported by industry; 164 of these kilns are located at facilities that are estimated to be major sources. Of the 164 periodic kilns located at major sources, 81 are located at brick manufacturing facilities and 83 are located at structural clay products manufacturing facilities.

The primary HAP emissions sources at BSCP manufacturing plants are tunnel kilns and periodic kilns, which emit HF, HCl, and HAP metals. Kilns also emit PM and SO_2. Other sources of HAP emissions at BSCP manufacturing plants are the raw material processing and handling equipment. The APCD that are used by the industry to control emissions from kilns include DIFF, DLS/FF, DLA, WS, and fabric filters.

B. What Are the Affected Sources?

The existing affected source, which is the portion of each source in the category for which we are setting emission standards, is any existing large tunnel kiln. Large tunnel kilns have a design capacity equal to or greater than 9.07 Mg/hr (10 tph) of fired product. Such tunnel kilns may be fired by natural gas or other fuels, including sawdust. Sawdust firing typically involves the use of a sawdust dryer because sawdust typically is purchased wet and needs to be dried before it can be used as fuel. Consequently, some sawdust-fired tunnel kilns have two process streams, including: A process stream that exhausts directly to the atmosphere or to an APCD, and a process stream in which the kiln exhaust is ducted to a sawdust dryer where it is used to dry sawdust before being emitted to the atmosphere.

Today's final rule focuses on those process streams from existing large tunnel kilns that exhaust directly to the atmosphere or to an APCD. For existing large tunnel kilns that do not have sawdust dryers, the kiln exhaust process stream (*i.e.*, the only process stream) is subject to the requirements of today's final rule. In accordance with CAA section 112(d)(1), we have divided tunnel kilns that duct exhaust to sawdust dryers into two classes for purposes of regulation. For existing large tunnel kilns that ducted exhaust to sawdust dryers prior to July 22, 2002, only the process stream that is emitted directly to the atmosphere or to an APCD is subject to the requirements of today's final rule; any process stream from such kilns that is ducted to a sawdust dryer is not subject to those requirements.

By contrast, for existing large tunnel kilns that first duct exhaust to sawdust dryers on or after July 22, 2002, all of the exhaust (*i.e.*, both the process stream that is emitted directly to the atmosphere or to an APCD and the process stream that is ducted to a sawdust dryer) is subject to the same level of control requirement as a new tunnel kiln.

In addition, each new or reconstructed tunnel kiln is an affected source and all process streams from new or reconstructed tunnel kilns are subject to the requirements of today's final rule. The requirements of today's final rule for new and reconstructed tunnel kilns are different for small and large kilns. Small tunnel kilns have design capacities less than 9.07 Mg/hr (10 tph) of fired product, and large tunnel kilns have design capacities equal to or greater than 9.07 Mg/hr (10 tph) of fired product. A source is a new affected source if construction began on or after July 22, 2002. An affected source is reconstructed if the criteria defined in 40 CFR 63.2 are met, as qualified by 40 CFR 63.8390(i). An affected source is existing if it is not new or reconstructed.

An existing tunnel kiln with a federally enforceable permit condition that restricts kiln operation to less than 9.07 Mg/hr (10 tph) of fired product on an annual average basis is not subject to the requirements of today's final rule. Kilns that are used exclusively for R&D and not used to manufacture products for commercial sale, except in a *de minimis* manner, are not subject to the requirements of today's final rule. Finally, kilns that are used exclusively for setting glazes on previously fired products are not subject to the requirements of today's final rule.

C. When Must I Comply With the Final Rule?

Existing affected sources must comply within 3 years of May 16, 2003. New and reconstructed affected sources with an initial startup before May 16, 2003 must comply no later than May 16, 2003. New and reconstructed affected sources with an initial startup after May 16, 2003 must comply upon initial startup. Existing area sources that subsequently become major sources have 3 years from the date they become major sources to come into compliance. Any portion of existing facilities that become new or reconstructed major sources and any new or reconstructed area sources that become major sources must be in compliance upon initial startup.

D. What Are the Emission Limits?

Today's final rule includes emission limits in the form of production-based mass emission limits and percent reduction requirements. In establishing the HAP emission limits, we selected PM as a surrogate for HAP metals (including mercury in particulate form). Today's final rule contains HF, HCl, and PM emission limits for existing, new, and reconstructed affected sources at BSCP manufacturing facilities, as well as for the following affected sources that would be considered reconstructed but for 40 CFR 63.8390(i): Existing small tunnel kilns whose design capacity is increased such that it is equal to or greater than 9.07 Mg/hr (10 tph) of fired product or existing large DLA-controlled kilns.

If you own or operate an existing large tunnel kiln, a new or reconstructed small tunnel kiln, an existing small kiln that is rebuilt such that it becomes a large kiln, or an existing large DLA-controlled kiln that is rebuilt, you must meet an HF emission limit of 0.029 kg/Mg (0.057 lb/ton) of fired product or reduce uncontrolled HF emissions by at least 90 percent for affected process streams. You must meet an HCl emission limit of 0.13 kg/Mg (0.26 lb/ton) of fired product or reduce uncontrolled HCl emissions by at least 30 percent. You are required to meet a PM emission limit of 0.21 kg/Mg (0.42 lb/ton) of fired product.

If you own or operate a new or reconstructed large tunnel kiln, you must meet an HF emission limit of 0.029 kg/Mg (0.057 lb/ton) of fired product or reduce uncontrolled HF emissions by at least 90 percent for all process streams. You must meet an HCl emission limit of 0.028 kg/Mg (0.056 lb/ton) of fired product or reduce uncontrolled HCl emissions by at least 85 percent. You are required to meet a PM emission limit of 0.060 kg/Mg (0.12 lb/ton) of fired product.

E. What Are the Operating Limits?

In addition to the emission limits, today's final rule includes operating limits that apply to APCD used to comply with the final rule. The operating limits require you to maintain certain process or APCD parameters within levels established during performance tests. Each facility affected by today's final rule is required to prepare, implement, and revise, as necessary, an OM&M plan. The OM&M plan generally specifies the operating parameters to be monitored; the frequency that parameter values will be determined; the limits for each parameter; procedures for proper operation and maintenance of APCD and monitoring equipment; procedures for responding to parameter deviations; and procedures for documenting compliance.

We have established operating limits for DLA, DIFF, DLS/FF, and WS. If you operate a DLA, you must maintain the average pressure drop across the DLA for each 3-hour block period at or above the average pressure drop established during the performance test. You also must maintain an adequate amount of limestone in the limestone hopper, storage bin (located at the top of the DLA), and DLA at all times. In addition, you must maintain the limestone feeder setting at or above the level established during the performance test and you must use the same grade of limestone from the same source as was used during the performance test. Finally, you must maintain no VE from the DLA stack.

If you operate a DIFF or DLS/FF, you must maintain free-flowing lime in the feed hopper or silo and to the APCD at all times and maintain the feeder setting at or above the level established during your performance test. In addition, you have the option of using a bag leak detection system or monitoring VE. If you use 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 OM&M plan, and 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. If you monitor VE, you must maintain no VE from the DIFF or DLS/FF stack.

If you operate a WS, you are required to maintain the average scrubber pressure drop, the average scrubber liquid pH, the average scrubber liquid flow rate, and the average chemical addition rate, if applicable, for each 3-hour block period at or above the average values established during your performance test.

If you own or operate an affected source equipped with an alternative APCD or technique not listed in the rule, you must establish operating limits for the appropriate operating parameters subject to prior written approval by the Administrator as described in 40 CFR 63.8(f). You are required to submit a request for approval of alternative monitoring procedures that includes a description of the alternative APCD or technique, the type of monitoring device or procedure that you would use, the appropriate operating parameters that you would monitor, and the frequency that the operating parameter values would be determined and recorded. You must establish site-specific operating limits during your performance test based on the information included in the approved alternative monitoring procedures request. You are required to install, operate, and maintain the parameter monitoring system for the alternative APCD or technique according to your OM&M plan.

F. What Are the Performance Test and Initial Compliance Requirements?

We are requiring owners and operators of all affected sources to conduct an initial performance test using specified EPA test methods to demonstrate initial compliance with the emission limits. A performance test must be conducted before renewing your 40 CFR part 70 operating permit or at least every 5 years following the initial performance test, as well as when an operating limit parameter value is being revised. You must test at the outlet of the APCD and prior to any releases to the atmosphere for all affected sources. If meeting the percent reduction emission limits for HF or HCl, you must also test at the APCD inlet. You must conduct each test while operating at the maximum production level.

Under today's final rule, you are required to measure emissions of HF, HCl, and PM. You must measure HF and HCl emissions using EPA Method 26A, ''Determination of Hydrogen Halide and Halogen Emissions from Stationary Sources-Isokinetic Method,'' 40 CFR part 60, appendix A, or any other alternative method that has been approved by the Administrator under 40 CFR 63.7(f) of the general provisions. The EPA Method 26, ''Determination of Hydrogen Chloride Emissions from Stationary Sources,'' 40 CFR part 60, appendix A, may be used when no acid particulate matter (*e.g.*, HF or HCl dissolved in water droplets emitted by sources controlled by a WS) is present. As an alternative to using EPA Methods 26A or 26, you may measure HF and HCl emissions using EPA Method 320 ''Measurement of Vapor Phase Organic and Inorganic Emission by Extractive FTIR'' 40 CFR part 63, appendix A. When using EPA Method 320, you must follow the analyte spiking procedures of section 13 of Method 320 unless you can demonstrate that the complete spiking procedure has been conducted at a similar source. Particulate matter emissions must be measured using EPA Method 5, ''Determination of Particulate Emissions from Stationary Sources,'' 40 CFR part 60, appendix A, or any other approved alternative method.

To determine initial compliance with the production-based mass emission limits for HF, HCl, and PM, you must calculate the mass emissions per unit of production for each test run using the mass emission rates of HF, HCl, and PM and the production rate (on a fired-product basis) measured during your performance test. To determine initial compliance with any of the percent reduction emission limits, you must calculate the percent reduction for each test run using the mass emission rates, measured during your performance test, of the specific HAP (HF or HCl) entering and exiting the APCD.

Prior to your initial performance test, you are required to install the CMS (*e.g.*, continuous parameter monitoring system) equipment to be used to demonstrate continuous compliance with the operating limits. During your initial test, you must use the CMS to establish site-specific operating parameter values that represent your operating limits.

If you operate a DLA, you must continuously measure the pressure drop across the DLA during the performance test and determine the 3-hour block average pressure drop. You also must maintain an adequate amount of limestone in the limestone hopper, storage bin (located at the top of the DLA), and DLA at all times. In addition, you must establish your limestone feeder setting one week prior to the performance test and maintain the feeder setting for the one-week period that precedes the performance test and during the performance test. Finally, you are required to document the source and grade of the limestone used during the performance test.

If you operate a DIFF or DLS/FF, you are required to ensure that lime in the feed hopper or silo and to the APCD is free-flowing at all times during the performance test, and you are required to record the feeder setting for the three test runs. If the lime feed rate varies, you are required to determine the average feed rate from the three test runs. If you use a bag leak detection system, you must submit analyses and supporting documentation demonstrating conformance with EPA guidance and specifications for bag leak detection systems.

If you operate a WS, you are required to continuously measure the scrubber pressure drop, the scrubber liquid pH, the scrubber liquid flow rate, and the chemical addition rate (if applicable). For each WS parameter, you are required to determine and record the average values for the three test runs and the 3-hour block average value.

G. What Are the Continuous Compliance Requirements?

Today's final rule requires that you demonstrate continuous compliance with each emission limitation that applies to you. You must follow the requirements in your OM&M plan and document conformance with your OM&M plan. You are required to operate a CMS to monitor the operating parameters established during your initial performance test as described in the following paragraphs. The CMS must collect data at least every 15 minutes, and you need to have at least three of four equally spaced data values (or at least 75 percent if you collect more than four data values per hour) per hour (not including startup, shutdown, malfunction, out-of-control periods, or periods of routine control device maintenance covered by a routine control device maintenance exemption) to have a valid hour of data. You must operate the CMS at all times when the process is operating. You also have to conduct proper maintenance of the CMS, including inspections, calibrations, and validation checks, and maintain an inventory of necessary parts for routine repairs of the CMS. Using the recorded readings, you must calculate and record the 3-hour block average values of each operating parameter. To calculate the average for each 3-hour averaging period, you must have at least 75 percent of the recorded readings for that period (not including startup, shutdown, malfunction, out-of-control periods, or periods of routine control device maintenance covered by a routine control device maintenance exemption).

If you operate a DLA, you must collect and record data documenting the DLA pressure drop and reduce the data to 3-hour block averages. You must maintain the average pressure drop across the DLA for each 3-hour block period at or above the average pressure drop established during the performance test. You also must verify that the limestone hopper, storage bin (located at the top of the DLA), and DLA contain an adequate amount of limestone by performing a daily visual check of the limestone hopper and the storage bin, and if the hopper or storage bin do not contain adequate limestone you must promptly initiate and complete corrective actions according to your OM&M plan. You also must record the limestone feeder setting daily to verify that the feeder setting is being maintained at or above the level established during the performance test. You also must use the same grade of limestone from the same source as was used during the performance test and maintain records of the source and type of limestone. Finally, you must perform daily, 15-minute VE observations in accordance with the procedures of EPA Method 22, ''Visual Determination of Fugitive Emissions from Material Sources and Smoke Emissions from Flares,'' 40 CFR part 60, appendix A. During the VE observations, the kiln must be operating under normal conditions. If VE are observed, you must promptly initiate and complete corrective actions according to your OM&M plan. If no VE are observed in 30 consecutive daily EPA Method 22 tests, you may decrease the frequency of EPA Method 22 testing from daily to weekly for that kiln stack. If VE are observed during any weekly test, you must promptly initiate and complete corrective actions according to your OM&M plan and you must resume EPA Method 22 testing of that kiln stack on a daily basis until no VE are observed in 30 consecutive daily tests, at which time you may again decrease the frequency of EPA Method 22 testing to a weekly basis.

For DIFF and DLS/FF systems, you must maintain free-flowing lime in the feed hopper or silo and to the APCD at all times. If lime is found not to be free flowing via the output of a load cell, carrier gas/lime flow indicator, carrier gas pressure drop measurement system, or other system, you must promptly initiate and complete corrective actions according to your OM&M plan. You also have to maintain the feeder setting at or above the level established during your performance test and record the feeder setting once each shift. If you use 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 OM&M plan. You also must 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 block reporting period. In calculating this operating time fraction, 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 must be counted as a minimum of 1 hour, and if you take longer than 1 hour to initiate corrective action, the alarm time must be counted as the actual amount of time taken to initiate corrective action. As an alternative to using a bag leak detection system, you may monitor VE. If you choose to monitor VE, you must perform daily, 15-minute VE observations in accordance with the procedures of EPA Method 22. During the VE observations, the kiln must be operating under normal conditions. If VE are observed, you must promptly initiate and complete corrective actions according to your OM&M plan. If no VE are observed in 30 consecutive daily EPA Method 22 tests, you may decrease the frequency of EPA Method 22 testing from daily to weekly for that kiln stack. If VE are observed during any weekly test, you must promptly initiate and complete corrective actions according to your OM&M plan and you must resume EPA Method 22 testing of that kiln stack on a daily basis until no VE are observed in 30 consecutive daily tests, at which time you may again decrease the frequency of EPA Method 22 testing to a weekly basis.

For WS, you are required to continuously maintain the 3-hour block averages for scrubber pressure drop, scrubber liquid pH, scrubber liquid flow rate, and chemical addition rate (if applicable) at or above the minimum values established during your performance test.

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

We are requiring owners and operators of all affected sources to submit initial notifications, notifications of performance tests, and notifications of compliance status by the specified dates in the final rule, which may vary depending on whether the affected source is new or existing. In addition to the information specified in 40 CFR

63.9(h)(2)(i), you are required to include the following in your notification of compliance status: (1) The operating limit parameter values established for each affected source (with supporting documentation) and a description of the procedure used to establish the values, and (2) if applicable, analysis and supporting documentation demonstrating conformance with EPA guidance and specifications for bag leak detection systems.

We are requiring owners and operators of all affected sources to submit semiannual compliance reports containing statements and information concerning emission limitation deviations, out-of-control CMS, periods of startup, shutdown, or malfunction, when actions consistent with your approved SSMP were taken, and periods of routine control device maintenance for facilities obtaining a routine control device maintenance exemption. In addition, if you undertake an action that is inconsistent with your approved SSMP, then you are required to submit a startup, shutdown, and malfunction report within 2 working days of starting such action and within 7 working days of ending such action unless you have made alternative arrangements with the permitting authority.

We are requiring owners and operators of all affected sources to maintain records for at least 5 years from the date of each record. You must retain the records onsite for at least the first 2 years but may retain the records offsite for the remaining 3 years. You are required to keep a copy of each notification and report, along with supporting documentation. You are required to keep records related to the following: (1) Records of startup, shutdown, or malfunction; (2) records of performance tests; (3) records to show continuous compliance with each emission limitation; (4) if a bag leak detection system is used, records of each bag leak detection system alarm, including the time of the alarm, the time corrective action was initiated and completed, and a description of the cause of the alarm and the corrective action taken; (5) if VE measurements are taken, records of VE observations; (6) records of each operating limit parameter value deviation, including the date, time, and duration of the deviation, a description of the cause of the deviation and the corrective action taken, and whether the deviation occurred during a period of startup, shutdown, or malfunction; (7) records of routine control device maintenance for facilities obtaining a routine control device maintenance exemption, including a copy of the approved request for a routine control device maintenance exemption; (8) records of production rate; (9) records for any approved alternative monitoring or test procedures; and (10) current copies of your SSMP and OM&M plan, including any revisions, with records documenting conformance.

IV. Summary of Environmental, Energy, and Economic Impacts for the Final Brick and Structural Clay Products Manufacturing NESHAP

A. What Are the Air Quality Impacts?

At the current level of control and 1996 production levels, nationwide emissions of HAP from the 169 BSCP facilities estimated to be major sources are about 6,000 Mg/yr (6,600 tpy). Under today's final rule, it is assumed that DLA will be installed on 89 tunnel kilns with production capacities equal to or greater than 9.07 Mg (10 tph)(that currently are not controlled with a DLA, DIFF, DLS/FF, or WS). This will result in an estimated reduction in nationwide HAP emissions of 2,100 Mg/yr (2,300 tpy).

Hydrogen fluoride emissions account for approximately 60 percent of the baseline HAP emissions. Hydrogen chloride emissions account for approximately 40 percent, with HAP metals comprising less than 1 percent of the baseline HAP emissions. Estimated nationwide emissions of HF, HCl, and HAP metals from existing major source BSCP facilities at the current level of control are 3,500 Mg/yr (3,900 tpy), 2,400 Mg/yr (2,600 tpy), and 24 Mg/yr (26 tpy), respectively. Implementation of today's final rule is estimated to reduce nationwide HF emissions from existing tunnel kilns by about 1,700 Mg/yr (1,900 tpy), and HCl will be reduced by 350 Mg/yr (390 tpy). Emissions of HAP metals are estimated to be reduced by 5.4 Mg/yr (5.9 tpy). Implementation of today's final rule also is estimated to reduce PM and SO_2 emissions by 740 Mg/yr (820 tpy) and 2,500 Mg/yr (2,800 tpy), respectively.

To project air quality impacts for new sources, we assumed that two large model tunnel kilns (each with a 13.6 Mg/hr (15 tph) capacity and equipped with DIFF) and one medium model tunnel kiln (with an 8.2 Mg/hr (9 tph) capacity and equipped with a DLA), will begin operation at the beginning of the first year following promulgation. We estimate that by implementing today's final rule, HF emissions from new sources will be reduced by 87 Mg/yr (96 tpy), HCl emissions will be reduced by 47 Mg/yr (52 tpy), and HAP metals emissions will be reduced by 0.48 Mg/yr (0.53 tpy). We also estimate that PM and SO_2 emissions from the new kilns will be reduced by 67 Mg/yr (74 tpy) and 170 Mg/yr (190 tpy), respectively.

Secondary air impacts associated with today's final BSCP rule are direct impacts that result from the operation of any new or additional APCD. The generation of electricity required to operate the APCD on new and existing kilns will result in 11 Mg/yr (12 tpy) of nitrogen oxides (NO_X) emissions in the first year following compliance with today's final rule. The electricity is assumed to be generated by natural gas-fired turbines.

B. What Are the Water and Solid Waste Impacts?

Because compliance with today's final rule is based on the use of DLA or DIFF, no water pollution impacts are estimated. However, facilities with available wastewater disposal options may choose to use wet scrubbers. Based on available information, each scrubber-controlled kiln could generate as much as about 5 million gallons per year of waste water (based on a 10 gallon per minute scrubber blowdown, which is the maximum permitted amount in the industry).

The solid waste disposal impacts that result from the use of DLA include the disposal of the spent limestone that is discharged from the DLA. We calculated the solid waste by taking the difference between the amount of limestone charged into the DLA and the amount of reacted limestone and then adding the amount of reaction products and PM captured. Implementation of today's final rule is estimated to increase solid waste from existing sources by 65,200 Mg/yr (71,900 tpy).

To project solid waste impacts for new sources, we assumed that two large model tunnel kilns (equipped with DIFF) and one medium model tunnel kiln (equipped with a DLA) will begin operation at the beginning of the first year following promulgation of the final rule. The analysis of solid waste from DLA is discussed in the previous paragraph. The solid waste disposal impacts that result from the use of DIFF include the disposal of the spent lime (or other sorbent) that is injected into the kiln exhaust stream and subsequently captured by a fabric filter. We calculated the solid waste by taking the difference between the amount of lime injected into the system and the amount of reacted lime, and then adding the amount of reaction products and PM captured. Stoichiometric ratios of 1.0 to 2.0 have been reported for the DIFF and DLS/FF in use in the brick manufacturing industry. The average stoichiometric ratio of 1.35 was used in this analysis. We estimate that implementing today's final rule will result in the generation of 1,410 Mg/yr (1,550 tpy) of solid waste from new sources.

C. What Are the Energy Impacts?

Energy impacts consist of the electricity needed to operate the APCD. Electricity requirements are driven primarily by the size of the fan needed in the APCD. We estimate the increase in electricity consumption that will result from implementation of the final rule to be 89 terajoules per year (84 billion British thermal units (Btu) per year) for existing sources.

To project energy impacts for new sources, we assumed that two large model tunnel kilns (equipped with DIFF) and one medium model tunnel kiln (equipped with a DLA) will begin operation at the beginning of the first year following promulgation of the final rule. We estimate the increase in energy consumption that will result from implementation of today's final rule to be 7.8 terajoules per year (7.4 billion Btu per year) for new sources.

D. Are There Any Additional Environmental and Health Impacts?

Reducing HAP emissions under today's final rule will lower occupational HAP exposure levels. The operation of APCD may increase occupational noise levels.

E. What Are the Cost Impacts?

For existing sources, nationwide total capital costs to implement today's final rule are estimated at $63 million, with total annualized costs of $24 million. The capital costs include the purchase and installation of DLA and monitoring equipment on 89 existing large tunnel kilns. The annualized costs include annualized capital costs of the control and monitoring equipment, operation and maintenance expenses, emission testing costs, and recordkeeping and reporting costs associated with installing and operating these 89 DLA, as well as the monitoring, recordkeeping and reporting, and emission testing costs on 20 additional APCD that currently are installed on existing large tunnel kilns.

To project costs for new sources, we assumed that two large model tunnel kilns (equipped with DIFF) and one medium model tunnel kiln (equipped with a DLA) will begin operation at the beginning of the first year following promulgation of the final rule. We estimate the capital costs associated with implementation of today's final rule to be $2.8 million for these three new sources. We estimate the annualized costs associated with implementation of today's final rule to be $1.14 million per year for new sources in the first year following promulgation of the rule.

We calculated the cost estimates using cost algorithms that are based on procedures from EPA's Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual (EPA 450/3–90–006, January 1990) and cost information provided by the BSCP industry. We estimated costs by developing model process units that correspond to the various sizes of kilns found at BSCP manufacturing facilities and assigning the model process units to each facility based on the kiln sizes at each facility. The facility costs were summed to determine total industry costs.

F. What Are the Economic Impacts?

We conducted a detailed economic impact analysis to determine the market- and industry-level impacts associated with today's final rule. The compliance costs of today's final rule are expected to increase the price of brick and reduce their domestic production and consumption. We project the price of brick to increase by just less than 1 percent and project no change in price for structural clay products. Domestic production of brick is expected to decline by close to 1 percent. In addition, foreign brick imports are estimated to increase while exports decrease, both by just under 1 percent. Since there is no expected change in the price of structural clay products, we predict no change in domestic production or foreign imports of structural clay products.

In terms of industry impacts, the brick producers are projected to experience a decrease in operating profits of about 10 percent, which reflects the compliance costs associated with brick production and the resulting reductions in revenues due to the increase in the price of brick and the reduced quantity purchased. Through the market impacts described above, today's final rule would create both positive and negative financial impacts on facilities within the BSCP manufacturing industry. The majority of facilities, almost 71 percent, are expected to experience profit increases with today's final rule; however, there are some facilities projected to lose profits (about 29 percent). Furthermore, the economic impact analysis indicates that of the 189 BSCP manufacturing facilities, two brick facilities are at risk of closure because of today's final rule, while none of the structural clay products facilities are at risk to close.

Based on the market analysis, the annual social costs of today's final rule are projected to be $23.3 million. This differs from the annual engineering costs of today's final rule because the social costs account for producer and consumer behavior. These social costs are distributed across the many consumers and producers of brick. Since there are no price changes occurring in the structural clay products market, the social costs of today's final rule are confined to the brick industry. The consumers of brick are expected to incur $14.7 million in costs associated with today's final rule, with domestic consumers bearing $14.6 million and foreign consumers bearing $0.07 million. Brick producers, in aggregate, are expected to bear the remaining $8.6 million annually in costs. Domestic producers incur $8.67 million while foreign producers gain $0.04 million annually.

We estimate that 15 new kilns will be built during the 5 years after promulgation of today's final rule. The total compliance costs associated with these kilns are projected to be less than 0.6 percent of the industry's value of shipments. The economic impact analysis estimated the impact of today's final rule on these new sources through a sensitivity analysis. According to that analysis, it is projected that anywhere from three to six of these new kilns will be delayed in coming on-line in the BSCP manufacturing industry due to today's final rule.

V. Summary of Responses to Major Comments and Changes to the Clay Ceramics Manufacturing Proposed NESHAP

In response to the public comments received on the proposed clay ceramics rule, we made several changes in developing today's final clay ceramics rule. The major comments and our responses and rule changes are summarized in the following sections. A more detailed summary can be found in the Response-to-Comments document, which is available from several sources (see SUPPLEMENTARY INFORMATION section).

A. Affected Source

1. Subcategories of Clay Ceramics Kilns

We proposed two subcategories of clay ceramics kilns: Continuous (tunnel or roller) kilns and batch (periodic) kilns. Based on the public comments received regarding APCD applicability, as described in section V.C of this preamble, we revised the subcategorization structure for today's final rule. Today's final rule is based on four subcategories of clay ceramics kilns: Ceramic tile or sanitaryware tunnel kilns with design capacities less than 9.07 Mg/hr (10 tph) of fired product, ceramic tile or sanitaryware tunnel kilns with design capacities equal to or greater than 9.07 Mg/hr (10 tph) of fired product, ceramic tile roller kilns, and periodic kilns.

2. R&D Kiln Definition

One commenter requested that we change the definition of research and development kiln so that it is consistent with the definition of R&D in section 112(c)(7) of the CAA and most other NESHAP. Therefore, today's final rule includes a revised definition of research and development kiln that is consistent with section 112(c)(7) of the CAA and other NESHAP.

3. Facilities Co-Located With Major Sources

Commenters indicated that considering a clay ceramics facility a major source because it is co-located with a major source (under a separate NESHAP) puts those facilities at a competitive disadvantage with competitors operating facilities that are not co-located. We understand these commenters' concerns. However, section 112 of the CAA requires us to regulate HAP emissions from all major source facilities, regardless of the processes or operations that make those facilities major sources. Thus, today's final rule applies for both co-located and stand-alone clay ceramics manufacturing facilities that are major sources.

B. Existing Source MACT

Four commenters concurred with the existing MACT floor of ''no emissions reductions'' for existing clay ceramics sources. To the contrary, one commenter charged that EPA has simply set MACT floors based on control technology type and that EPA did not identify the relevant best performers and set floors reflecting their average emission level. The commenter noted that factors other than control device type affect emissions and that EPA must consider all non-negligible factors in setting MACT floors and considering beyond-the-floor measures. The commenter stated that if EPA believes it is unworkable to consider all factors, then perhaps EPA should base standards on actual emissions data which reflects all the factors influencing a source's performance.

We reevaluated our existing source MACT determinations following proposal based on consideration of factors other than APCD type. We agree that factors other than APCD type (*e.g.*, kiln design, fuel type, raw materials, additives and surface coatings) can affect emissions from clay ceramics kilns. We acknowledged the effect of kiln design on emissions by creating separate subcategories for periodic, roller, and tunnel kilns. We maintain that low-HAP raw material use is not a viable MACT option because, similar to the BSCP industry, all facilities use product-specific raw materials that are integral to the various products. Changes in raw materials would change the end products, and because of this, it would not be feasible for facilities to meet requirements based on the use of low-HAP raw materials. With respect to requiring kilns to fire low-HAP fuels, all clay ceramics kilns for which we have information are fired with natural gas or propane. Therefore, we are not concerned that a requirement to use natural gas (or equivalent fuel) to fire all existing kilns would have any impact on the end products of existing kilns, as would be the case in the BSCP industry. Therefore, the MACT floor for all existing clay ceramics periodic kilns, tunnel kilns, and roller kilns is based on firing the kilns with natural gas or an equivalent fuel (such as propane or other clean-burning fuel), and we added a work practice standard to the final rule that covers this requirement. We considered developing emission limitations based on firing natural gas, but the available data are insufficient for us to determine the contribution of kiln fuel to HAP emissions, and we believe that a work practice standard is the only feasible means of addressing the commenter's concern that we did not consider options besides APCD use.

C. New Source MACT

At proposal, we concluded that MACT for new and reconstructed periodic kilns was ''no emissions reductions.'' We concluded that MACT for new and reconstructed tunnel and roller kilns was the level of control achievable with a DIFF, DLS/FF, or WS because the best-controlled similar source (a BSCP tunnel kiln) had this level of control.

Following proposal, several commenters argued that clay ceramics kilns are different from BSCP kilns, and that EPA should not consider BSCP tunnel kilns to be the best-controlled similar source. The commenters noted that clay ceramics kilns typically have much lower throughput than BSCP kilns and that the exhaust from clay ceramics kilns contains lower pollutant concentrations than BSCP kiln exhaust. Commenters stated that the lower pollutant concentrations in clay ceramics kiln exhaust would result in the inability to achieve high removal efficiencies. The commenters suggested that the proposed control technologies are not transferable to clay ceramics kilns and noted that none of the technologies are currently in use on domestic clay ceramics kilns. The commenters suggested that the best-controlled similar source should come from the sources in the clay ceramics source category, which would result in a new source MACT floor of ''no emissions reductions'' for clay ceramics kilns.

One commenter stated that, whereas brick products are fired unglazed, most sanitaryware products have a ceramic glaze applied before firing, which melts in the kiln, evenly covering the surface of the piece, helping to seal the surface and hinder the emission of by-products typically associated with the clay raw material.

One commenter suggested that MACT for new clay ceramics kilns be applied only to large kilns (*i.e.*, kilns with a design capacity equal to or greater than 9.07 Mg/hr (10 tph) of fired product). The commenter suggested (based on their conversation with an APCD vendor) that DIFF systems may not be readily available for small (less than 9.07 Mg/hr (10 tph)) clay ceramics kilns.

One commenter requested that EPA distinguish between ceramic tile tunnel and roller kilns. The commenter stated that the two major design differences between BSCP periodic and new BSCP tunnel kilns are the same dissimilarities exhibited between clay ceramics tunnel and roller kilns. The commenter also provided reasons why clay ceramics roller kilns are different from BSCP tunnel kilns. The commenter stated that BSCP tunnel kilns are made of brick lined with refractory materials, have a high profile (tall) design, and require setting and stacking product on rail cars which move on floor rails. Bricks are fired on a 15 to 24 hour cycle. Ceramic tile roller kilns are designed in modular units with a low (short) profile (which affects the excess airflow), have different firing curves and flow characteristics, process a single row of tile moved by roller, and utilize high velocity burners for turbulent airflow. The tiles are not stacked and are fired on a 40 to 60 minute cycle. The commenter stated that firing time has a significant effect on the evolution of HF emissions (roller kilns exhibit significantly lower HF emissions) and provided detail of firing curves/emission estimates for the two types of kilns. In addition, the commenter stated that APCD available for BSCP tunnel kilns are not readily available for roller kilns.

We acknowledge that the control technologies (DIFF, DLS/FF, and WS) that formed the basis for the proposed emission limits for new and reconstructed clay ceramics kilns are not currently in use on any domestic clay ceramics kiln. However, 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. To the contrary, our interpretation of section 112(d) of the CAA is that we are obligated to consider similar sources from other source categories in determining the best-controlled similar source for establishing MACT for new sources.

We have reevaluated our subcategory and best-controlled similar source determinations for new and reconstructed clay ceramics kilns. We maintain that MACT for new and reconstructed periodic kilns does not require use of add-on APCD because the best-controlled similar source is uncontrolled. In addition, based on the comments received and other information, we have concluded that there are significant differences between clay ceramics tunnel kilns and roller kilns. We believe that differences in the operation of BSCP tunnel kilns and tile roller kilns, particularly with respect to the duration of firing, result in emission characteristics that are likely to be very dissimilar. As a result, we cannot assume that APCD that have been demonstrated to be effective for reducing HF and HCl emissions from BSCP tunnel kilns are feasible for tile roller kilns. Therefore, we have concluded that BSCP tunnel kilns cannot be considered similar sources to tile roller kilns, and we have determined that MACT for new and reconstructed clay ceramics tile roller kilns does not include control with an add-on APCD.

We disagree that there are technological differences between clay ceramics tunnel kilns and BSCP tunnel kilns. Some tunnel kilns actually produce both ceramic tile and structural clay tile (a structural clay product). Regarding the effect of glazing on emissions, we cannot refute that the glazes applied to sanitaryware form a seal that could prevent further release of certain pollutants from the body of the ware. However, we have no information that indicates that the sealing becomes effective before HF and HCl are released. To the contrary, we have data from several tests on sanitaryware kilns that quantify HF emissions, and the tests indicate that uncontrolled emissions are within the range emitted from BSCP kilns.

We maintain that the best-controlled similar source for a clay ceramics tunnel kiln is a BSCP tunnel kiln. As discussed in section II.D of this preamble, MACT for new and reconstructed BSCP tunnel kilns with design capacities less than 9.07 Mg/hr (10 tph) of fired product is based on use of a DLA, while MACT for new and reconstructed BSCP tunnel kilns with design capacities equal to or greater than 9.07 Mg/hr (10 tph) of fired product is based on use of DIFF, DLS/FF, or WS. Thus, we have adopted the same requirements for new and reconstructed clay ceramics tunnel kilns. New and reconstructed clay ceramics tile and sanitaryware tunnel kilns with design capacities less than 9.07 Mg/hr (10 tph) of fired product will be required to meet emission limits based on the levels of control that can be achieved by a kiln controlled with a DLA. The emission limits for HF are 0.029 kg/Mg (0.057 lb/ton) or at least 90 percent reduction. For HCl, the emission limits are 0.13 kg/Mg (0.26 lb/ton) or at least 30 percent reduction. For PM, which is used as a surrogate for HAP metals, the emission limit is 0.21 kg/Mg (0.42 lb/ton). For new and reconstructed clay ceramics tile and sanitaryware tunnel kilns with design capacities equal to or greater than 9.07 Mg/hr (10 tph) of fired product, we have revised the emission limits (based on the levels of control that can be achieved by a kiln controlled with a DIFF, DLS/FF, or WS) to reflect new data that were considered in the development of the final BSCP rule, as discussed in section II.F of this preamble. The revised HF emission limits are 0.029 kg/Mg (0.057 lb/ton) or at least 90 percent reduction. The revised HCl emission limits are 0.028 kg/Mg (0.056 lb/ton) or at least 85 percent reduction. The PM emission limit remains unchanged (from proposal) at 0.060 kg/Mg (0.12 lb/ton).

Similar to the requirements for existing sources, we added a work practice standard that requires facilities to use natural gas, or an equivalent fuel, to fire all new or reconstructed clay ceramics periodic kilns, tunnel kilns, and roller kilns, except during periods of natural gas curtailment or other periods when natural gas is not available.

Similar to the requirements for BSCP tunnel kilns, two types of clay ceramics tunnel kilns that would otherwise be considered reconstructed do not meet the definition of reconstruction in 40 CFR 63.2. We have added language in 40 CFR 63.8450(f) to provide that it is not technologically and economically feasible for these two types of existing kilns that would otherwise meet the criteria for reconstruction under 40 CFR 63.2 to meet the relevant standards—*i.e.*, new source MACT. The two types of kilns are existing tunnel kilns with design capacities less than 9.07 Mg/hr (10 tph) of fired product whose design capacities are increased such that they are equal to or greater than 9.07 Mg/hr (10 tph) of fired product, and existing DLA-controlled tunnel kilns with design capacities equal to or greater than 9.07 Mg/hr (10 tph) of fired product. These sources will be required to meet emission limits based on the levels of control that can be achieved by a kiln controlled with a DLA. They also will be subject to the work practice standard that requires facilities to use natural gas, or an equivalent fuel, to fire all kilns, except during periods of natural gas curtailment or other periods when natural gas is not available.

We acknowledge that the higher airflow rates that are characteristic of clay ceramics kilns result in lower pollutant concentrations in the exhaust stream, and that control efficiency limits (or percentage reduction limits) are more difficult to achieve when exhaust gas concentrations are lower. For that reason, we proposed and are promulgating today production-based mass emission limits as alternatives to the HF and HCl percentage reduction limits. Exhaust gas concentrations have no effect on mass emission rates, provided the concentrations are above the test method detection limit. The mass emission rate (*e.g.*, pounds of pollutant emitted per hour) for a source is unchanged regardless of how much dilution air is introduced. Therefore, even though a clay ceramics kiln with a diluted exhaust stream may not be able to meet the percentage HF and HCl reduction limits, the available data indicate that a kiln that is controlled to the new source MACT level will be able to meet the production-based emission limits for HF and HCl, as well as the production-based limit for PM.

D. Cost and Economic Impacts

Several commenters stated that EPA underestimated the cost per ton of pollutant removed at proposal. In general, the commenters felt the costs were unreasonable. Commenters questioned the public health benefits of the proposed clay ceramics rule.

One commenter stated that EPA entirely misunderstood the economic state of the ceramic tile industry in the U.S., and therefore, grossly underestimated the economic impact of the proposed rule on the industry. The commenter challenged the assumptions presented in the algorithms on which the cost analysis is based, charging that they bear no reasonable relationship to reality in the industry and that the APCD strategies are not actually feasible for implementation. The commenter also argued that the economic analysis of the MACT floor for reconstructed and new ceramic clay roller kilns does not support DIFF-, DLS/FF- or WS-based controls.

We acknowledge the commenters' statements about the high cost effectiveness of the proposed rule. As discussed previously, we have revised the rule, as proposed, such that it is now less costly. Under today's final rule, new clay ceramic roller kilns will not be subject to emission limits. In addition, we have subcategorized clay ceramics tunnel kilns by design capacity. New and reconstructed tunnel kilns with design capacities less than 9.07 Mg/hr (10 tph) of fired product and tunnel kilns that would be considered reconstructed but for 40 CFR 63.8540(f)(1) or 40 CFR 63.8540(f)(2) will be required to meet emission limits based on the levels of control that can be achieved by a DLA. In addition to the changes mentioned above, we have added a work practice standard that requires facilities to use natural gas, or an equivalent fuel, to fire all clay ceramics kilns, except during periods of natural gas curtailment or other periods when natural gas is not available. The costs associated with this change are minimal. Based on these changes, there will be no control cost for new roller kilns and the control cost for new and reconstructed tunnel kilns with design capacities less than 9.07 Mg/hr (10 tph) of fired product and tunnel kilns that would be considered reconstructed but for 40 CFR 63.8540(f)(1) or 40 CFR 63.8540(f)(2) will be lower than at proposal. Most of the new tunnel kilns constructed will likely be in this smaller size category. New clay ceramics tunnel kilns with design capacities equal to or greater than 9.07 Mg/hr (10 tph) are still required to meet emission limits based on the use of DIFF, DLS/FF or WS technologies. However, the HF and HCl emission limits are slightly less stringent than at proposal (due to the inclusion of new test data). The PM emission limit for new clay ceramics tunnel kilns with design capacities equal to or greater than 9.07 Mg/hr (10 tph) is unchanged from the proposed requirements for all new kilns.

Public health benefits are likely to be realized due to the reduced emissions and reduced exposures to emissions as a result of today's final rule. However, we have not quantified these public health benefits because we are not required to do so under the CAA.

We disagree with the commenter's statement that the economic impacts of the rule on the ceramic tile industry have been grossly underestimated. Based on revisions to the final rule as described above, we expect minimal impacts on existing sources, based on recordkeeping and reporting costs associated with the work practice standard for existing kilns, and we estimate that only one new source will be impacted by the final rule in the first five years following promulgation. Therefore, the EIA at proposal overestimated the impacts on the industry. Thus, it is very unlikely that the one new source affected by the rule or the addition of a work practice standard that requires all kilns to be fired with natural gas (or equivalent fuel) will be able to influence industry prices or foreign competition.

E. Test Data and Emission Limits

One commenter implied that there are no data to suggest that HCl is emitted from ceramic tile kilns. Another commenter stated that limits for HCl and PM are irrelevant and that we should only set an emission limit for HF (the largest single HAP emitted from the kilns). The commenter believes that there is no need to establish an emission limitation for HCl or PM because any control system designed to achieve the required HF reduction will also reduce HCl and PM. One commenter disagreed that PM is an adequate surrogate for HAP metals emissions.

We are required by section 112(d) of the CAA to establish emission limits for listed HAP emitted from major sources. Section 112(b) of the CAA lists HCl and various HAP metals. We believe that PM is an adequate surrogate for HAP metals for the reasons discussed in section II.F of this preamble.

We acknowledge that we have no test data that demonstrate that HCl is emitted from clay ceramics kilns. However, we do have data that show that chlorides are present in many clay materials, and that HCl is emitted from various types of clays when heated above a minimum temperature. The data include raw material analyses and emission test reports of HCl emissions for the BSCP manufacturing, lightweight aggregate manufacturing, and kaolin processing industries. Because of the similarities in raw materials used in those industries and the raw materials used to manufacture clay ceramics, we assume that clay ceramics kilns also emit HCl.

We agree that HF emission rates from clay ceramics kilns generally are greater than the corresponding emission rates for HCl or metal HAP. We also agree that emission controls that are used to meet the emission limits for HF are likely to reduce emissions of HCl and SO_x as well. However, as stated previously, the CAA requires us to set emission limits for all listed HAP based on MACT. The data indicated that there are existing controls on similar sources that achieve significant reductions in emissions of HCl and PM (as a surrogate for metal HAP). Therefore, we are required to establish emission limits for HCl and metal HAP. We also note that, if HCl and PM emissions from any affected source are negligible or are automatically controlled by HF control devices, complying with the HCl and PM emission limits should not present a problem.

F. Monitoring Requirements

1. Fabric Filter Inlet Temperature

Two commenters disagreed with the proposed fabric filter inlet temperature monitoring requirement. One commenter stated that control systems using hydrated lime are generally known to have increased HCl and HF removal when temperatures increase. The other commenter suggested that the only limit on fabric filter inlet temperature should be based on manufacturer's specifications for protection of the equipment.

We have eliminated the requirement for monitoring fabric filter inlet temperatures on affected kilns that are controlled with a DLS/FF or DIFF. We believe that the other monitoring requirements (*e.g.*, lime feed rate monitoring and periodic VE checks) that we have incorporated into today's final rule are adequate for ensuring continuous compliance with the emission limits.

2. Bag Leak Detection Systems and Visible Emissions

One commenter suggested changes to the amount of bag leak detector alarm time that must be recorded. We have not changed the requirements for recording bag leak detection system downtime. However, we have incorporated into today's final rule an option for owners and operators of affected kilns that are controlled with a DLS/FF, or DIFF to perform daily VE checks rather than using bag leak detection systems. Visible emissions checks are required for DLA-controlled kilns. Today's final rule also includes a provision for decreasing the frequency of VE checks provided no VE are observed.

3. Continuous Emissions Monitoring Systems

In the preamble to the proposed rule, we requested comment on requiring the application of PM CEMS as a method to assure continuous compliance with the proposed PM emission limits. Commenters opposed use of CEMS when less expensive, but effective, parametric monitoring alternatives are available. Therefore, today's final rule does not require use of PM CEMS or any other type of CEMS. We believe that the parameter monitoring requirements specified in the final rule are adequate for ensuring continuous compliance.

4. Test Methods

One commenter requested that the final clay ceramics rule provide facilities with the option to use either EPA Method 26A or EPA Method 320 for all required stack testing for HF emissions, HCl emissions, or both. Because EPA Method 320 will provide accurate HF and HCl measurements, we have modified today's final clay ceramics rule to include EPA Method 320 as an alternative to EPA Method 26A.

G. Startup, Shutdown, and Malfunction

1. Bypass

One commenter requested that EPA allow for use of the bypass stack during periods of APCD maintenance. Similar comments were received on the proposed BSCP rule. Therefore, today's final clay ceramics rule allows for bypass of the APCD during periods of routine control device maintenance for up to 4 percent of the annual kiln operating hours. Section II.H of this preamble presents details on use of this routine control device maintenance exemption.

2. Initial Startup

Commenters on both the proposed BSCP rule and clay ceramics rule pointed out that it is impractical to meet emission standards during initial startup of a tunnel kiln. Thus, as discussed in section II.H of this preamble, we have added a definition of initial startup to today's final clay ceramics rule to address the concerns expressed by the commenters.

VI. Summary of the Final Clay Ceramics Manufacturing NESHAP

A. What Source Category Is Regulated by the Final Rule?

Today's final rule for clay ceramics manufacturing applies to clay ceramics manufacturing facilities that are, are located at, or are part of, a major source of HAP emissions. The clay ceramics manufacturing source category includes those facilities that manufacture pressed floor tile, pressed wall tile, and other pressed tile; or sanitaryware (toilets and sinks). Clay ceramics are primarily composed of clay and shale, and may include many different additives, including silica, talc, and various high purity powders produced by chemical synthesis. Clay ceramics manufacturing generally includes raw material processing and handling and forming of the tile or sanitaryware shapes, followed by drying, glazing, and firing. Most clay ceramics are coated with a glaze prior to firing. The clay ceramics industry also includes dinnerware and pottery manufacturing, but these industry segments are not covered by today's final rule because we determined that there are no dinnerware or pottery manufacturing facilities that are major sources of HAP.

Available information shows a total of 58 facilities that produce clay ceramics. Thirty-two of these facilities, located in 16 States, primarily produce pressed tile, while 26 of these facilities, located in 15 States, primarily produce sanitaryware. Eight of the 58 clay ceramics manufacturing facilities are estimated to be major sources. Thirteen clay ceramics facilities are owned by small businesses, and none of the small business-owned facilities are estimated to be major sources.

All clay ceramics are fired in kilns. Firing may be performed in one or more stages. Tile can be fired in either continuous (tunnel or roller) or batch (periodic) kilns, but most facilities use either tunnel or roller kilns for tile production. Periodic kilns are usually used at smaller facilities or are used primarily for second-firing a product after a glaze has been applied.

The sanitaryware industry uses either tunnel kilns or periodic kilns for firing. Tunnel kilns account for most sanitaryware firing; periodic kilns are used primarily for refiring rejected pieces that have been repaired and re-glazed. Some smaller facilities use periodic kilns for all firing operations.

The primary HAP emission sources at clay ceramics manufacturing plants are roller, tunnel, and periodic kilns which emit HF, HCl, and HAP metals. Kilns also emit PM and SO_2. Currently, no APCD are used by the clay ceramics industry to control emission from kilns, although the industry's emissions are minimized because the kilns fire clean-burning fuels. Other sources of HAP emissions at clay ceramics manufacturing plants are the raw material processing and handling equipment.

B. What Are the Affected Sources?

The affected sources, which are the portions of each source in the category for which we are setting emission standards, include each existing, new, or reconstructed periodic kiln, tunnel kiln, and roller kiln. Each tunnel kiln that meets the description in 40 CFR 63.8540(f)(1) or 40 CFR 63.8540(f)(2) also is an affected source. All affected sources are subject to the work practice standard in today's final rule. In addition, today's final rule contains different emission limits, based on design capacity, for new and reconstructed tunnel kilns, and also includes emission limits for tunnel kilns that would otherwise meet the criteria for reconstruction but for 40 CFR 63.8540(f)(1) or 40 CFR 63.8540(f)(2). The tunnel kiln subcategories are tunnel kilns with design capacities less than 9.07 Mg/hr (10 tph) of fired product and tunnel kilns with design capacities equal to or greater than 9.07 Mg/hr (10 tph) of fired product. Kilns that are used exclusively for R&D and not used to manufacture products for commercial sale, except in a *de minimis* manner, are not subject to the requirements of today's final rule. Kilns that are used exclusively for refiring or for setting glazes on previously fired products are not subject to the requirements of today's final rule.

A source is a new affected source if construction began on or after July 22, 2002. An affected source is reconstructed if the criteria defined in 40 CFR 63.2 are met, as qualified by 40 CFR 63.8540(f). An affected source is existing if it is not new or reconstructed and does not meet the descriptions in 40 CFR 63.8540(f). As indicated, affected sources described in 40 CFR 63.8540(f) also are subject to today's final rule.

C. When Must I Comply With the Final Rule?

New and reconstructed affected sources and affected sources that would be considered reconstructed but for 40 CFR 63.8540(f)(1) or 40 CFR 63.8540(f)(2) with an initial startup before May 16, 2003 must comply no later than May 16, 2003. New and reconstructed affected sources and affected sources that would be considered reconstructed but for 40 CFR 63.8540(f)(1) or 40 CFR 63.8540(f)(2) with an initial startup after May 16, 2003 must comply upon initial startup. Any portion of existing facilities that become new or reconstructed major sources and any new or reconstructed area sources that become major sources must be in compliance upon initial startup.

If you have an existing affected source, you must comply with the work practice standards within 3 years of May 16, 2003.

D. What Are the Emission Limits?

Today's final rule includes emission limits in the form of production-based mass emission limits and percent reduction requirements. In establishing the HAP emission limits, we selected PM as a surrogate for HAP metals, including mercury in particulate form. Today's final rule includes HF, HCl, and PM emission limits for new and reconstructed affected sources at clay ceramics manufacturing facilities, as well as for the following affected sources that would be considered reconstructed but for 40 CFR 63.8540(f): Existing tunnel kilns with design capacities less than 9.07 Mg/hr (10 tph) of fired product whose design capacities are increased such that they are equal to or greater than 9.07 Mg/hr (10 tph) of fired product, and existing DLA-controlled tunnel kilns with design capacities equal to or greater than 9.07 Mg/hr (10 tph) of fired product.

If you own or operate a new or reconstructed tunnel kiln with a design capacity less than 9.07 Mg/hr (10 tph) of fired product or a tunnel kiln that would be considered reconstructed but for 40 CFR 63.8540(f)(1) or 40 CFR 63.8540(f)(2), you are required to meet an HF emission limit of 0.029 kg/Mg (0.057 lb/ton) of fired product or reduce uncontrolled HF emissions by at least 90 percent. You also are required to meet an HCl emission limit of 0.13 kg/Mg (0.26 lb/ton) of fired product or reduce uncontrolled HCl emissions by at least 30 percent. Finally, you are required to meet a PM emission limit of 0.21 kg/Mg (0.42 lb/ton) of fired product.

If you own or operate a new or reconstructed tunnel kiln with a design capacity equal to or greater than 9.07 Mg/hr (10 tph) of fired product, you are required to meet an HF emission limit of 0.029 kg/Mg (0.057 lb/ton) of fired product or reduce uncontrolled HF emissions by at least 90 percent. You also are required to meet an HCl emission limit of 0.028 kg/Mg (0.056 lb/ton) of fired product or reduce uncontrolled HCl emissions by at least 85 percent. Finally, you are required to meet a PM emission limit of 0.06 kg/Mg (0.12 lb/ton) of fired product.

E. What Are the Operating Limits?

The operating limits for new and reconstructed clay ceramics tunnel kilns and tunnel kilns that would be considered reconstructed but for 40 CFR 63.8540(f)(1) or 40 CFR 63.8540(f)(2) are the same as those for new and reconstructed BSCP tunnel kilns. These operating limits are presented in section III.E of this preamble.

F. What Are the Work Practice Standards?

If you have an existing, new, or reconstructed clay ceramics periodic kiln, tunnel kiln, or roller kiln, or a tunnel kiln that would be considered reconstructed but for 40 CFR 63.8540(f)(1) or 40 CFR 63.8540(f)(2), you must use natural gas, or an equivalent fuel, as the kiln fuel at all times except during periods of natural gas curtailment or other periods when natural gas is not available.

G. What Are the Performance Test and Initial Compliance Requirements for Sources Subject to Emission Limits?

The performance test and initial compliance requirements for new and reconstructed clay ceramics tunnel kilns and tunnel kilns that would be considered reconstructed but for 40 CFR 63.8540(f)(1) or 40 CFR 63.8540(f)(2) are the same as those for new and reconstructed BSCP tunnel kilns. These requirements are presented in section III.F of this preamble.

H. What Are the Initial Compliance Requirements for Sources Subject to a Work Practice Standard?

For each existing, new, or reconstructed clay ceramics periodic kiln, tunnel kiln, or roller kiln, and each tunnel kiln that would be considered reconstructed but for 40 CFR 63.8540(f)(1) or 40 CFR 63.8540(f)(2), you must indicate, in your initial notification, that you use natural gas, or an equivalent fuel, as the kiln fuel, and certify that such information is true, accurate, and complete.

I. What Are the Continuous Compliance Requirements for Sources Subject to Emission Limits?

The continuous compliance requirements for new and reconstructed clay ceramics tunnel kilns and tunnel kilns that would be considered reconstructed but for 40 CFR 63.8540(f)(1) or 40 CFR 63.8540(f)(2) are the same as those for new and reconstructed BSCP tunnel kilns. These requirements are presented in section III.G of this preamble.

J. What Are the Continuous Compliance Requirements for Sources Subject to a Work Practice Standard?

For each existing, new, or reconstructed clay ceramics periodic kiln, tunnel kiln, or roller kiln, and each tunnel kiln that would be considered reconstructed but for 40 CFR 63.8540(f)(1) or 40 CFR 63.8540(f)(2), you must use natural gas, or an equivalent fuel, as the kiln fuel, and document the type of fuel used. The type of fuel used, along with other compliance information, must be certified as part of your compliance reports. During periods of natural gas curtailment or other periods when natural gas is unavailable, you are allowed to use an alternative fuel. However, if you use an alternative fuel, you must meet the notification requirements specified in 40 CFR 63.8630(g) and the reporting requirements specified in 40 CFR 63.8635(g).

K. What Are the Notification, Recordkeeping, and Reporting Requirements for Sources Subject to Emission Limits?

The notification, recordkeeping, and reporting requirements for new and reconstructed clay ceramics tunnel kilns and tunnel kilns that would be considered reconstructed but for 40 CFR 63.8540(f)(1) or 40 CFR 63.8540(f)(2) are the same as those for new and reconstructed BSCP tunnel kilns. These requirements are presented in section III.H of this preamble.

L. What Are the Notification, Recordkeeping, and Reporting Requirements for Sources Subject to a Work Practice Standard?

If you operate an existing, new, or reconstructed clay ceramics periodic kiln, tunnel kiln, or roller kiln, or a tunnel kiln that would be considered reconstructed but for 40 CFR 63.8540(f)(1) or 40 CFR 63.8540(f)(2), you must submit an initial notification that indicates that you use natural gas, or an equivalent fuel, as the kiln fuel. You must keep records that document your kiln fuel, and if you must use an alternative fuel due to a natural gas curtailment or other interruption of natural gas supply, you must submit a notification of alternative fuel use that includes the information specified in 40 CFR 63.8630(g). You must submit a report of alternative fuel use within 10 working days after terminating the use of the alternative fuel. The report must include the information specified in 40 CFR 63.8635(g).

VII. Summary of Environmental, Energy, and Economic Impacts for the Final Clay Ceramics Manufacturing NESHAP

A. What Are the Air Quality Impacts?

Because the only requirements for existing sources under today's final rule are work practice standards that we believe that all facilities are already meeting, no air quality impacts are projected for existing sources. To project air quality impacts for new sources, we assumed that one sanitaryware tunnel kiln (3.6 Mg/hr (4 tph) capacity) equipped with a DLA will begin operation at the beginning of the first year following promulgation of the rule. We estimate that by implementing the rule, HF emissions from this new source will be reduced by 4.9 Mg/yr (5.4 tpy), HCl emissions will be reduced by 1.0 Mg/yr (1.1 tpy), and HAP metals emissions will be reduced by 0.028 Mg/yr (0.031 tpy). We also estimate that PM and SO_2 emissions from the new kiln will be reduced by 3.9 Mg/yr (4.3 tpy) and 13 Mg/yr (14 tpy), respectively.

Secondary air impacts associated with today's final clay ceramics rule are direct impacts that result from the operation of any new APCD. The generation of electricity required to operate the control device on the projected new kiln will result in 0.09 tpy of NO_X emissions in the first year following promulgation of the rule. The electricity was assumed to be generated by natural gas-fired turbines.

B. What Are the Water and Solid Waste Impacts?

Because the only requirements for existing sources under today's final rule are work practice standards that we believe that all facilities are already meeting, no water and solid waste impacts are projected for existing sources. Our analyses are based on the use of DLA for controlling new kilns and, therefore, no water impacts are projected for new sources. To project solid waste impacts for new sources, we assumed that one sanitaryware tunnel kiln equipped with a DLA will begin operation at the beginning of the first year following promulgation of the rule. The solid waste disposal impacts that result from the use of DLA will include the disposal of spent limestone. We calculated the solid waste by taking the difference between the amount of limestone charged into the DLA and the amount of reacted limestone and then adding the amount of reaction products and PM captured. We estimate that implementing the rule will result in the generation of 290 Mg/yr (320 tpy) of solid waste from the new source.

C. What Are the Energy Impacts?

Because the only requirements for existing sources under today's final rule are work practice standards that we believe that all facilities are already meeting, no energy impacts are projected for existing sources. To project energy impacts for new sources, we assumed that one sanitaryware tunnel kiln equipped with a DLA will begin operation at the beginning of the first year following promulgation of the rule. Energy impacts consist of the electricity needed to operate the DLA. Electricity requirements are driven primarily by the size of the fan needed in the control device. We estimate the increase in energy consumption that would result from implementation of the rule to be 710 gigajoules per year (670 million Btu per year).

D. Are There Any Additional Environmental and Health Impacts?

Reducing HAP emissions under today's final rule will lower occupational HAP exposure levels. The operation of APCD may increase occupational noise levels.

E. What Are the Cost Impacts?

Because the only requirements for existing sources under today's final rule are work practice standards that we believe that all facilities are already meeting, cost impacts projected for existing sources are based only on recordkeeping and reporting requirements associated with the work practice standard. These costs are $1,193 per year for each of the eight major source facilities, and the total annual cost to the industry for existing sources is $9,533. To project costs for new sources, we assumed that one sanitaryware tunnel kiln, equipped with a DLA, will be built during the first year following promulgation. We estimate the capital costs associated with implementation of the rule to be $510,000 for new sources. The capital costs include the purchase and installation of DLA and monitoring equipment. We estimate the annualized costs associated with implementation of the rule to be $170,000 per year for new sources. The annualized costs include annualized capital costs of the control and monitoring equipment, operation and maintenance expenses, emission testing costs, and recordkeeping and reporting costs associated with installing and operating the DLA.

We calculated the cost estimates using cost algorithms that are based on procedures from EPA's OAQPS Control Cost Manual (EPA 450/3–90–006, January 1990) and cost information provided by the BSCP industry and control device vendors. We estimated costs by developing model process units that correspond to the various sizes of kilns found at clay ceramics manufacturing facilities.

F. What Are the Economic Impacts?

We did not prepare a revised economic impact analysis for the clay ceramics industry because the requirements of the final rule will result in a decrease in cost impacts on the industry. Specifically, new and reconstructed roller kilns, which would have been subject to emission limits in the rule as proposed, are not subject to emission limits in the final rule. In addition, the requirements for clay ceramics tunnel kilns with design capacities less than 9.07 Mg/hr (10 tph) are based on control with a DLA rather than the more costly DIFF, DLS/FF, or WS systems on which the proposed rule was based.

The goal of the economic impact analysis is to estimate the market response of clay ceramics manufacturing producers to today's final rule and to determine the economic effects that may result due to the final rule. Because the MACT floor for existing clay ceramics kilns is based on firing natural gas, or an equivalent fuel, and all clay ceramics kilns for which we have data are fired by natural gas or propane, the compliance costs for existing sources associated with today's final rule consist only of recordkeeping and reporting costs and are minimal. The aggregate price of ceramic products is, therefore, expected to remain the same. Because the prices of ceramic products are not expected to change due to today's final rule, there are no projected changes in domestic production, domestic consumption, or foreign trade. Therefore, no economic impacts on existing major sources are expected from today's final rule.

Unlike existing sources, new and reconstructed tunnel kilns used to produce clay ceramics will face positive compliance costs associated with the installation and operation of APCD. We estimate that one new 3.6 Mg/hr (4 tph) capacity tunnel kiln will be constructed in the sanitaryware industry during the first 5 years after the rule is promulgated. Industry compliance costs associated with this kiln are expected to be less than 0.1 percent of industry value of shipments for the sanitaryware industry. No level of cost-to-sales for sanitaryware kilns could be developed due to the diversity of product types that they produce.

VIII. Statutory and Executive Order Reviews

A. Executive Order 12866, Regulatory Planning and Review

Under Executive Order 12866 (58 FR 51735, October 4, 1993), EPA must determine whether the 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 obligations 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, it has been determined that today's BSCP final rule is a ''significant regulatory action'' because it raises novel legal or policy issues within the meaning of paragraph (4) above. Consequently, today's final BSCP rule was submitted to OMB for review under Executive Order 12866. Any written comments from OMB and written EPA responses are available in the docket (see **ADDRESSES** section of this preamble).

Pursuant to the terms of Executive Order 12866, it has been determined that the clay ceramics final rule does not constitute a ''significant regulatory action'' because it does not meet any of the above criteria. Consequently, today's final clay ceramics rule was not submitted to OMB for review under Executive Order 12866.

B. Paperwork Reduction Act

The information collection requirements in today's final rules will be submitted for approval to OMB under the requirements of the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* The EPA has prepared an Information Collection Request (ICR) document for each of the rules (ICR No. 2022.01 for BSCP manufacturing and ICR No. 2023.01 for clay ceramics manufacturing), and a copy of either document may be obtained from Susan Auby by mail at Office of Environmental Information, Collection Strategies Division (2822T), U.S. EPA, 1200 Pennsylvania Avenue, NW, Washington, DC 20460; by e-mail at *auby.susan@epa.gov*; or by calling (202) 566–1672. You may also download a copy off the Internet at *http://www.epa.gov/icr*. The information 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 EPA's policies set forth in 40 CFR part 2, subpart B.

Today's final BSCP rule will not require any notifications or reports beyond those required by the NESHAP General Provisions. The recordkeeping requirements require only the specific information needed to assure compliance.

With one exception, today's final clay ceramics rule will not require any notifications or reports beyond those required by the NESHAP General Provisions. The exception applies to affected sources that are subject to limits on the type of fuel used. In such cases, the owner or operator may use an alternative fuel under certain conditions but must submit a notification before using the alternative fuel and must report on alternative fuel use after terminating use of the alternative fuel. The recordkeeping requirements require only the specific information needed to assure compliance.

The annual monitoring, reporting, and recordkeeping burden for the collection of information required by today's final BSCP manufacturing rule (averaged over the first 3 years after the effective date of the final rule) is estimated to be 17,471 labor hours per year at a total annual labor cost of $900,328. This burden estimate includes a one-time submission of an OM&M plan; one-time submission of a SSMP, with immediate reports for any event when the procedures in the plan were not followed; semiannual compliance reports; maintenance inspections; notifications; and recordkeeping. Total annualized capital/startup costs associated with the monitoring requirements over the 3-year period of the ICR are estimated at $115,111, with operation and maintenance costs of $4,853/yr.

The annual monitoring, reporting, and recordkeeping burden for the collection of information required by today's final clay ceramics manufacturing rule (averaged over the first 3 years after the effective date of the final rule) is estimated to be 185 labor hours per year at a total annual labor cost of $9,533. This burden estimate includes a one-time submission of an OM&M plan; one-time submission of a SSMP, with immediate reports for any event when the procedures in the plan were not followed; semiannual compliance reports; maintenance inspections; notifications; and recordkeeping. Total annualized capital/startup costs associated with the monitoring requirements over the 3-year period of the ICR are estimated at $1,824, with operation and maintenance costs of $358/yr.

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 and 48 CFR chapter 15. The OMB control numbers for the information collection requirements in the final rules will be listed in an amendment to 40 CFR part 9 in a subsequent **Federal Register** document after OMB approves the ICRs.

C. Regulatory Flexibility Act

The EPA has determined that it is not necessary to prepare a regulatory flexibility analysis in connection with this action. After considering the economic impacts of today's final rule on small entities in the two source categories, the EPA has determined that this action will not have a significant economic impact on a substantial number of small entities. Although today's final rule will not have a significant economic impact on a substantial number of small entities, we have nonetheless tried to minimize the impact of the final rule on small entities. For both the BSCP manufacturing and clay ceramics manufacturing source categories, we exercised flexibility in minimizing impacts on small entities through subcategorization of tunnel kilns by size, which still benefits the environment by requiring greater emissions reductions from the larger kilns. In addition, for the BSCP manufacturing source category, we contacted the small entities estimated to incur impacts in excess of 1 percent of sales to explain the rule's regulatory approach, as well as a potential alternative to installing an APCD. Facilities with existing tunnel kilns operating at or near 10 tph could accept a permit condition that restricts kiln production to less than 10 tph and, therefore, places the kiln in the subcategory unaffected by the standards for existing kilns.

For purposes of assessing the impact of today's action on small entities, small entities are defined as: (1) A small business according to Small Business Administration (SBA) size standards; (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 which is independently owned and operated and is not dominant in its field. The following two sections provide descriptions of the small business assessments for the two categories of sources addressed by today's action.

1. Brick and Structural Clay Products (BSCP) Manufacturing

Small Business Administration size standards for BSCP manufacturing, by NAICS code, are shown in Table 2 of this preamble.

TABLE 2.—SMALL BUSINESS SIZE STANDARDS FOR BSCP MANUFACTURING

NAICS code	Size standard, number of employees
327121	500
327122	500
327123	500
327125	750
327993	750

We have determined that 76 of the 89 companies owning BSCP manufacturing facilities are small businesses. Although small businesses represent 86 percent of the companies within the source category, they are expected to incur about 21 percent of the total industry engineering compliance costs of $24 million. Additionally, 61 of the 76 small businesses will incur no costs. Under the final rule, we estimate that three small firms in this source category may experience an impact less 1 percent of sales, nine small firms in this source category may experience an impact between 1 percent and 3 percent of sales, and 3 small businesses (or 20 percent) may experience an impact greater than 3 percent of sales.

We also conducted an economic impact analysis that accounted for firm behavior to provide an estimate of the facility and market impacts of the proposed rule. The analysis projected that of the 189 facilities in this source category, two facilities are at risk of closure. Neither of these facilities is owned by a small business. The median compliance cost is below 1 percent of sales for both small and large firms affected by the proposed rule (0.0 and 0.1 percent for small and large firms, respectively).

Fifteen new BSCP manufacturing sources are projected to be constructed during the five years after promulgation of the rule. Industry compliance costs associated with these sources are anticipated to be less than 0.6 percent of the BSCP manufacturing industry's value of shipments. According to the new source economic impact analysis, three to six of these new sources may be delayed in coming on-line due to the compliance costs they would face. We cannot determine with certainty whether these new sources will be built by large or small companies. Regardless, impacts at the company level are not expected to be significant for a substantial number of small entities.

2. Clay Ceramics Manufacturing

Small Business Administration size standards for clay ceramics manufacturing, by NAICS code, are shown in Table 3 of this preamble.

TABLE 3.—SMALL BUSINESS SIZE STANDARDS FOR CLAY CERAMICS MANUFACTURING

NAICS code	Size standard, number of employees
326191	500
327111	750
327112	500
327122	500
327123	500
327125	750
335121	500
421220	100
421320	100

The EPA identified 13 of the 29 companies owning clay ceramics manufacturing facilities as small businesses. Because the clay ceramics manufacturing final rule does not include emissions limits for existing kilns and includes only a work practice standard that requires that existing kilns are fired with natural gas, a firm's existing kilns will be minimally impacted by the final rule. One new sanitaryware manufacturing source is projected to be constructed in the first five years following promulgation of the rule. Industry compliance costs associated with this source are expected to be less than 0.1 percent of industry value of shipments for the sanitaryware industry segments. No level of cost-to-sales for the new sanitaryware manufacturing source could be developed due to the diversity of product types produced. Thus, new clay ceramics manufacturing sources are expected to face positive compliance costs; however, we cannot determine with certainty whether these sources will be built by large or small companies. Regardless, impacts at the company level are not expected to be significant for a substantial number of small entities.

D. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Pub. L. 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, the EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with "Federal mandates" that may result in expenditures by State, local, and tribal governments, in the aggregate, or by the private sector, of $100 million or more in any 1 year. Before promulgating an EPA rule for which a written statement is needed, section 205 of the UMRA generally requires EPA 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 EPA to adopt an alternative other than the least costly, most cost-effective, or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted. Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, it must have developed, under section 203 of the UMRA, a small government agency plan. 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 EPA's regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

The EPA has determined that today's final rules do not contain 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. The total annual cost for today's final BSCP rule for any 1 year is estimated at $24 million. The total annual cost for today's final clay ceramics rule for any 1 year is estimated at $9,500. Thus, today's final rules are not subject to the requirements of sections 202 and 205 of the UMRA. In addition, the EPA has determined that today's final rules contain no regulatory requirements that might significantly or uniquely affect small governments because they contain no regulatory requirements that apply to such governments or impose obligations upon them. Therefore, today's final rules are not subject to the requirements of section 203 of the UMRA.

E. Executive Order 13132, Federalism

Executive Order 13132 (64 FR 43255, August 10, 1999) 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'' is 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.'' Under Executive Order 13132, the EPA may not issue a regulation that has federalism implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by State and local governments, or EPA consults with State and local officials early in the process of developing the proposed regulation. The EPA also may not issue a regulation that has federalism implications and that preempts State law unless EPA consults with State and local officials early in the process of developing the proposed regulation.

If EPA complies by consulting, Executive Order 13132 requires EPA to provide to OMB, in a separately identified section of the preamble to the rule, a federalism summary impact statement (FSIS). The FSIS must include a description of the extent of EPA's prior consultation with State and local officials, a summary of the nature of their concerns and EPA's position supporting the need to issue the regulation, and a statement of the extent to which the concerns of State and local officials have been met. Also, when EPA transmits a draft final rule with federalism implications to OMB for review pursuant to Executive Order 12866, it must include a certification from EPA's Federalism Official stating that EPA has met the requirements of Executive Order 13132 in a meaningful and timely manner.

Today's final rules do not have federalism implications. They 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. None of the affected facilities are owned or operated by State governments, and the final rule requirements will not supercede State regulations that are more stringent. Thus, the requirements of Executive Order 13132 do not apply to the final rules.

F. Executive Order 13175, Consultation and Coordination With Indian Tribal Governments

Executive Order 13175 (65 FR 67249, November 6, 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.'' ''Policies that have tribal implications'' are defined in the Executive Order to include regulations that have ''substantial direct effects on one or more Indian tribes, on the relationship between the Federal government and the Indian tribes, or on the distribution of power and responsibilities between the Federal government and Indian tribes.''

Today's final rules do not have tribal implications. They will not have substantial direct effects on tribal governments, on the relationship between the Federal government and Indian tribes, or on the distribution of power and responsibilities between the Federal government and Indian tribes, as specified in Executive Order 13175. No tribal governments are known to own or operate BSCP or clay ceramics manufacturing facilities. Thus, Executive Order 13175 does not apply to the final rules.

G. Executive Order 13045, Protection of Children From Environmental Health & Safety Risks

Executive Order 13045 (62 FR 19885, April 23, 1997) applies to any rule that: (1) Is determined to be ''economically significant'' as defined under Executive Order 12866, and (2) concerns the environmental health or safety risk that EPA has 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 rule on children, and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by 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 rule. Today's final rules are not subject to Executive Order 13045 because they are 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, OMB, 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 proposed rulemaking, and notices of proposed 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.'' Today's final clay ceramics manufacturing rule is not subject to Executive Order 13211 because it is not a significant regulatory action under Executive Order 12866. Although today's final BSCP rule is considered to be a significant regulatory action under Executive Order 12866, it 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.

Today's final BSCP rule affects manufacturers in the BSCP (NAICS 327121), extruded tile (NAICS 327122), and other structural clay products (NAICS 327123) industries. There is no crude oil, fuel, or coal production from these industries. Hence, there is no direct effect on such energy production related to implementation of the BSCP rule. In fact, as previously mentioned in this preamble, there will be an increase in energy consumption, and hence an increase in energy production, resulting from installation of APCD likely needed for sources to meet the requirements of the final BSCP rule. This increase in energy consumption is equal to approximately 27 million kilowatt-hours/year (kWh/yr) for electricity. The electricity increase is considered negligible, equivalent to 0.0007 percent of 1999 U.S. electricity production.[4] There is no expected increase in natural gas consumption. It should be noted, however, that the estimated decrease in BSCP production resulting from producer's and consumer's reactions to the final BSCP rule will offset this effect on such energy production. It is likely that the output reduction in the industries will lead to less energy use by these industries and thus some reduction in overall energy production.

Given the negligible change in energy consumption resulting from the final BSCP rule, we do not expect any price increase for any energy type. The cost of energy distribution should not be affected by the final BSCP rule at all since the final rule does not affect energy distribution facilities. Finally, with changes in net exports being a minimal percentage of domestic output from the affected industries, there will be only a negligible change in international trade, and hence in dependence on foreign energy supplies. No other adverse outcomes are expected to occur with regards to energy supplies.

Therefore, we conclude that today's final BSCP rule 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. No. 104–113; 15 U.S.C. 272 note) directs 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 OMB, with explanations when an agency does not use available and applicable voluntary consensus standards.

The final rules involve technical standards. The EPA cites the following standards in the final rules: EPA Methods 1, 1A, 2, 2A, 2C, 2D, 2F, 2G, 3, 4, 5, 22, 26, 26A, and 320 of 40 CFR part 60, appendix A. 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 1A, 2A, 2D, 2F, 2G, and 22. The search and review results have been documented and are in the dockets for the final rules.

The search for emissions measurement procedures identified 11 voluntary consensus standards. The EPA determined that eight of these 11 standards identified for measuring emissions of the HAPs or surrogates subject to emission standards in the final rules were impractical alternatives to EPA test methods for the purposes of the final rules. Therefore, EPA does not intend to adopt these standards at this time. The reasons for this determination for the 11 methods are discussed in the dockets for the final rules.

Two of the 11 voluntary consensus standards identified in this search were not available at the time the review was conducted for the purposes of the final rules 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.

In response to public comments received, we considered and decided to include EPA Method 320 as an option for measuring HF and HCl. The voluntary consensus standard ASTM D6348–98, ''Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform (FTIR) Spectroscopy,'' has been reviewed by the EPA as a potential alternative to EPA Method 320. Suggested revisions to ASTM D6348–98 that would allow the EPA to accept ASTM D6348–98 as an acceptable alternative were sent to ASTM by the EPA. The ASTM Subcommittee D22–03 is currently undertaking a revision of ASTM D6348–98. Because of this, we are not citing this standard as an acceptable alternative for EPA Method 320 in the final rules today. However, upon successful ASTM balloting and demonstration of technical equivalency with the EPA FTIR methods, the revised ASTM standard could be incorporated by reference for EPA regulatory applicability. In the interim, facilities have the option to request ASTM D6348–98 as an alternative test method under 40 CFR 63.7(f) and 40 CFR 63.8(f) on a case-by-case basis.

Table 3 of the final BSCP rule and Table 4 of the final clay ceramics rule list the EPA testing methods included in the rules. Under 40 CFR 63.7(f) and 40 CFR 63.8(f), 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 today's final rules and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rules in the **Federal Register**. Neither of today's rules are ''major rules'' as defined by 5 U.S.C. 804(2). The final rules will be effective on May 16, 2003.

List of Subjects in 40 CFR Part 63

Administrative practice and procedure, Air pollution control, Hazardous substances, Intergovernmental relations, Reporting and recordkeeping requirements.

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[4] U.S. Department of Energy, Energy Information Administration. Annual Energy Review, End-Use Energy Consumption for 1998. Located on the Internet at *http://www.eia.doe.gov.*

Dated: February 28, 2003.

Christine Todd Whitman,

Administrator.

■ For the reasons stated in the preamble, title 40, chapter I, part 63 of the Code of the 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.*

■ 2. Part 63 is amended by adding subpart JJJJJ to read as follows:

Subpart JJJJJ—National Emission Standards for Hazardous Air Pollutants for Brick and Structural Clay Products Manufacturing

Sec.

What This Subpart Covers

Emission Limitations

General Compliance Requirements

Testing and Initial Compliance Requirements

Continuous Compliance Requirements

Notifications, Reports, and Records

Other Requirements and Information

Tables to Subpart JJJJJ of Part 63

What This Subpart Covers

§ 63.8380 What is the purpose of this subpart?

This subpart establishes national emission limitations for hazardous air pollutants (HAP) emitted from brick and structural clay products (BSCP) manufacturing facilities. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations.

§ 63.8385 Am I subject to this subpart?

You are subject to this subpart if you own or operate a BSCP manufacturing facility that is, is located at, or is part of, a major source of HAP emissions according to the criteria in paragraphs (a) and (b) of this section.

(a) A BSCP manufacturing facility is a plant site that manufactures brick (including, but not limited to, face brick, structural brick, and brick pavers); clay pipe; roof tile; extruded floor and wall tile; and/or other extruded, dimensional clay products. Brick and structural clay products manufacturing facilities typically process raw clay and shale, form the processed materials into bricks or shapes, and dry and fire the bricks or shapes.

(b) A major source of HAP emissions is any stationary source or group of stationary sources within a contiguous area under common control that emits or has the potential to emit any single HAP at a rate of 9.07 megagrams (10 tons) or more per year or any combination of HAP at a rate of 22.68 megagrams (25 tons) or more per year.

§ 63.8390 What parts of my plant does this subpart cover?

(a) This subpart applies to each existing, new, or reconstructed affected source at a BSCP manufacturing facility.

(b) The existing affected source is an existing tunnel kiln with a design capacity equal to or greater than 9.07 megagrams per hour (Mg/hr) (10 tons per hour (tph)) of fired product according to paragraphs (b)(1) through (3) of this section. For the remainder of this subpart, a tunnel kiln with a design capacity equal to or greater than 9.07 Mg/hr (10 tph) of fired product will be called a large tunnel kiln, and a tunnel kiln with a design capacity less than 9.07 Mg/hr (10 tph) of fired product will be called a small tunnel kiln.

(1) For existing tunnel kilns that do not have sawdust dryers, the kiln exhaust process stream (*i.e.*, the only process stream) is subject to the requirements of this subpart.

(2) For existing tunnel kilns that ducted exhaust to sawdust dryers prior to July 22, 2002, only the kiln exhaust process stream (*i.e.*, the process stream that exhausts directly to the atmosphere or to an air pollution control device (APCD)) is subject to the requirements of this subpart. As such, any process stream that is ducted to a sawdust dryer is not subject to these requirements.

(3) For existing tunnel kilns that first ducted exhaust to sawdust dryers on or after July 22, 2002, all of the exhaust (*i.e.*, all process streams) is subject to the requirements of this subpart.

(c) An existing small tunnel kiln whose design capacity is increased such that it is equal to or greater than 9.07 Mg/hr (10 tph) of fired product is subject to the requirements of this subpart.

(d) An existing tunnel kiln with a federally enforceable permit condition that restricts kiln operation to less than 9.07 Mg/hr (10 tph) of fired product on a 12-month rolling average basis is not subject to the requirements of this subpart.

(e) Each new or reconstructed tunnel kiln is an affected source regardless of design capacity. All process streams from each new or reconstructed tunnel kiln are subject to the requirements of this subpart.

(f) Kilns that are used exclusively for research and development (R&D) and are not used to manufacture products for commercial sale, except in a de minimis manner, are not subject to the requirements of this subpart.

(g) Kilns that are used exclusively for setting glazes on previously fired products are not subject to the requirements of this subpart.

(h) A source is a new affected source if construction of the affected source began after July 22, 2002, and you met the applicability criteria at the time you began construction.

(i) An affected source is reconstructed if you meet the criteria as defined in § 63.2, except as provided in paragraphs (i)(1) and (i)(2) of this section.

(1) It is not technologically and economically feasible for an existing small tunnel kiln whose design capacity is increased such that it is equal to or greater than 9.07 Mg/hr (10 tph) of fired product to meet the relevant standards (*i.e.*, new source maximum achievable control technology (MACT)) by retrofitting with a dry lime injection fabric filter (DIFF), dry lime scrubber/fabric filter (DLS/FF), or wet scrubber (WS).

(2) It is not technologically and economically feasible for an existing large dry limestone adsorber (DLA)-controlled kiln to meet the relevant standards by retrofitting with a DIFF, DLS/FF, or WS.

(j) An affected source is existing if it is not new or reconstructed.

§ 63.8395 When do I have to comply with this subpart?

(a) If you have a new or reconstructed affected source, you must comply with this subpart according to paragraphs (a)(1) and (2) of this section.

(1) If the initial startup of your affected source is before May 16, 2003, then you must comply with the applicable emission limitations in Tables 1 and 2 to this subpart no later than May 16, 2003.

(2) If the initial startup of your affected source is after May 16, 2003, then you must comply with the applicable emission limitations in Tables 1 and 2 to this subpart upon initial startup of your affected source.

(b) If you have an existing affected source, you must comply with the applicable emission limitations in Tables 1 and 2 to this subpart no later than May 16, 2003.

(c) If you have an existing area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, you must be in compliance with this subpart according to paragraphs (c)(1) and (2) of this section.

(1) Any portion of the existing facility that is a new affected source or a new reconstructed source must be in compliance with this subpart upon startup.

(2) All other parts of the existing facility must be in compliance with this subpart by 3 years after the date the area source becomes a major source.

(d) If you have a new area source (*i.e.*, an area source for which construction or reconstruction commenced after July 22, 2002) that increases its emissions or its potential to emit such that it becomes a major source of HAP, you must be in compliance with this subpart upon initial startup of your affected source as a major source.

(e) You must meet the notification requirements in § 63.8480 according to the schedule in § 63.8480 and in 40 CFR part 63, subpart A. Some of the notifications must be submitted before you are required to comply with the emission limitations in this subpart.

Emission Limitations

§ 63.8405 What emission limitations must I meet?

(a) You must meet each emission limit in Table 1 to this subpart that applies to you.

(b) You must meet each operating limit in Table 2 to this subpart that applies to you.

§ 63.8410 What are my options for meeting the emission limitations?

To meet the emission limitations in Tables 1 and 2 to this subpart, you must use one or more of the options listed in paragraphs (a) and (b) of this section.

(a) *Emissions control system.* Use an emissions capture and collection system and an APCD and demonstrate that the resulting emissions or emissions reductions meet the emission limits in Table 1 to this subpart, and that the capture and collection system and APCD meet the applicable operating limits in Table 2 to this subpart.

(b) *Process changes.* Use low-HAP raw materials or implement manufacturing process changes and demonstrate that the resulting emissions or emissions reductions meet the emission limits in Table 1 to this subpart.

General Compliance Requirements

§ 63.8420 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limitations (including operating limits) in this subpart at all times, except during periods of startup, shutdown, and malfunction and during periods of routine control device maintenance as specified in paragraph (e) of this section.

(b) Except as specified in paragraph (e) of this section, 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). During the period between the compliance date specified for your affected source in § 63.8395 and the date upon which continuous monitoring systems (CMS) (*e.g.*, continuous parameter monitoring systems) have been installed and verified and any applicable operating limits have been set, you must maintain a log detailing the operation and maintenance of the process and emissions control equipment.

(c) You must develop and implement a written startup, shutdown, and malfunction plan (SSMP) according to the provisions in § 63.6(e)(3).

(d) You must prepare and implement a written operation, maintenance, and monitoring (OM&M) plan according to the requirements in § 63.8425.

(e) If you own or operate an affected kiln and must perform routine maintenance on the control device for that kiln, you may bypass the kiln control device and continue operating the kiln upon approval by the Administrator provided you satisfy the conditions listed in paragraphs (e)(1) through (5) of this section.

(1) You must request a routine control device maintenance exemption from the Administrator. Your request must justify the need for the routine maintenance on the control device and the time required to accomplish the maintenance activities, describe the maintenance activities and the frequency of the maintenance activities, explain why the maintenance cannot be accomplished during kiln shutdowns, describe how you plan to minimize emissions to the greatest extent possible during the maintenance, and provide any other documentation required by the Administrator.

(2) The routine control device maintenance exemption must not exceed 4 percent of the annual operating uptime for each kiln.

(3) The request for the routine control device maintenance exemption, if approved by the Administrator, must be incorporated by reference in and attached to the affected source's title V permit.

(4) You must minimize HAP emissions during the period when the kiln is operating and the control device is offline.

(5) You must minimize the time period during which the kiln is operating and the control device is offline.

(f) You must be in compliance with the provisions of subpart A of this part, except as noted in Table 7 to this subpart.

§ 63.8425 What do I need to know about operation, maintenance, and monitoring plans?

(a) You must prepare, implement, and revise as necessary an OM&M plan that includes the information in paragraph (b) of this section. Your OM&M plan must be available for inspection by the permitting authority upon request.

(b) Your OM&M plan must include, as a minimum, the information in paragraphs (b)(1) through (13) of this section.

(1) Each process and APCD to be monitored, the type of monitoring device that will be used, and the operating parameters that will be monitored.

(2) A monitoring schedule that specifies the frequency that the parameter values will be determined and recorded.

(3) The limits for each parameter that represent continuous compliance with the emission limitations in § 63.8405. The limits must be based on values of the monitored parameters recorded during performance tests.

(4) Procedures for the proper operation and routine and long-term maintenance of each APCD, including a maintenance and inspection schedule that is consistent with the manufacturer's recommendations.

(5) Procedures for installing 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 APCD).

(6) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction system.

(7) Continuous monitoring system performance evaluation procedures and acceptance criteria (*e.g.*, calibrations).

(8) Procedures for the proper operation and maintenance of monitoring equipment consistent with the requirements in §§ 63.8450 and 63.8(c)(1), (3), (4)(ii), (7), and (8).

(9) Continuous monitoring system data quality assurance procedures consistent with the requirements in § 63.8(d).

(10) Continuous monitoring system recordkeeping and reporting procedures consistent with the requirements in § 63.10(c), (e)(1), and (e)(2)(i).

(11) Procedures for responding to operating parameter deviations, including the procedures in paragraphs (b)(11)(i) through (iii) of this section.

(i) Procedures for determining the cause of the operating parameter deviation.

(ii) Actions for correcting the deviation and returning the operating parameters to the allowable limits.

(iii) Procedures for recording the times that the deviation began and ended and corrective actions were initiated and completed.

(12) Procedures for keeping records to document compliance.

(13) If you operate an affected kiln and you plan to take the kiln control device out of service for routine maintenance, as specified in § 63.8420(e), the procedures specified in paragraphs (b)(13)(i) and (ii) of this section.

(i) Procedures for minimizing HAP emissions from the kiln during periods of routine maintenance of the kiln control device when the kiln is operating and the control device is offline.

(ii) Procedures for minimizing the duration of any period of routine maintenance on the kiln control device when the kiln is operating and the control device is offline.

(c) Changes to the operating limits in your OM&M plan require a new performance test. If you are revising an operating limit parameter value, you must meet the requirements in paragraphs (c)(1) and (2) of this section.

(1) Submit a notification of performance test to the Administrator as specified in § 63.7(b).

(2) After completing the performance tests to demonstrate that compliance with the emission limits can be achieved at the revised operating limit parameter value, you must submit the performance test results and the revised operating limits as part of the Notification of Compliance Status required under § 63.9(h).

(d) If you are revising the inspection and maintenance procedures in your OM&M plan, you do not need to conduct a new performance test.

Testing and Initial Compliance Requirements

§ 63.8435 By what date must I conduct performance tests?

You must conduct performance tests within 180 calendar days after the compliance date that is specified for your source in § 63.8395 and according to the provisions in § 63.7(a)(2).

§ 63.8440 When must I conduct subsequent performance tests?

(a) You must conduct a performance test before renewing your 40 CFR part 70 operating permit or at least every 5 years following the initial performance test.

(b) You must conduct a performance test when you want to change the parameter value for any operating limit specified in your OM&M plan.

§ 63.8445 How do I conduct performance tests and establish operating limits?

(a) You must conduct each performance test in Table 3 to this subpart that applies to you.

(b) Before conducting the performance test, you must install and calibrate all monitoring equipment.

(c) Each performance test must be conducted according to the requirements in § 63.7 and under the specific conditions in Table 3 to this subpart.

(d) You must test while operating at the maximum production level.

(e) You may not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in § 63.7(e)(1).

(f) You must conduct at least 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) You must use the data gathered during the performance test and the equations in paragraphs (g)(1) and (2) of this section to determine compliance with the emission limitations.

(1) To determine compliance with the production-based hydrogen fluoride (HF), hydrogen chloride (HCl), and particulate matter (PM) emission limits in Table 1 to this subpart, you must calculate your mass emissions per unit of production for each test run using Equation 1 of this section:

$$MP = \frac{ER}{P} \qquad \text{(Eq. 1)}$$

Where:

MP=mass per unit of production, kilograms (pounds) of pollutant per megagram (ton) of fired product

ER=mass emission rate of pollutant (HF, HCl, or PM) during each performance test run, kilograms (pounds) per hour

P=production rate during each performance test run, megagrams (tons) of fired product per hour.

(2) To determine compliance with the percent reduction HF and HCl emission limits in Table 1 to this subpart, you must calculate the percent reduction for each test run using Equation 2 of this section:

$$PR = \frac{ER_i - ER_o}{ER_i}(100) \qquad \text{(Eq. 2)}$$

Where:

PR=percent reduction, percent

ER_i=mass emission rate of specific HAP (HF or HCl) entering the

APCD, kilograms (pounds) per hour
ER_o=mass emission rate of specific HAP (HF or HCl) exiting the APCD, kilograms (pounds) per hour.

(h) You must establish each site-specific operating limit in Table 2 to this subpart that applies to you as specified in Table 3 to this subpart.

(i) For each affected kiln that is equipped with an APCD that is not addressed in Table 2 to this subpart or that is using process changes as a means of meeting the emission limits in Table 1 to this subpart, you must meet the requirements in § 63.8(f) and paragraphs (i)(1) and (2) of this section.

(1) Submit a request for approval of alternative monitoring procedures to the Administrator no later than the notification of intent to conduct a performance test. The request must contain the information specified in paragraphs (i)(1)(i) through (iv) of this section.

(i) A description of the alternative APCD or process changes.

(ii) The type of monitoring device or procedure that will be used.

(iii) The operating parameters that will be monitored.

(iv) The frequency that the operating parameter values will be determined and recorded to establish continuous compliance with the operating limits.

(2) Establish site-specific operating limits during the performance test based on the information included in the approved alternative monitoring procedures request and, as applicable, as specified in Table 3 to this subpart.

§ 63.8450 What are my monitoring installation, operation, and maintenance requirements?

(a) You must install, operate, and maintain each CMS according to your OM&M plan and the requirements in paragraphs (a)(1) through (5) of this section.

(1) Conduct a performance evaluation of each CMS according to your OM&M plan.

(2) The CMS must complete a minimum of one cycle of operation for each successive 15-minute period. To have a valid hour of data, you must have at least three of four equally spaced data values (or at least 75 percent if you collect more than four data values per hour) for that hour (not including startup, shutdown, malfunction, out-of-control periods, or periods of routine control device maintenance covered by a routine control device maintenance exemption as specified in § 63.8420(e)).

(3) Determine and record the 3-hour block averages of all recorded readings, calculated after every 3 hours of operation as the average of the previous 3 operating hours. To calculate the average for each 3-hour average period, you must have at least 75 percent of the recorded readings for that period (not including startup, shutdown, malfunction, out-of-control periods, or periods of routine control device maintenance covered by a routine control device maintenance exemption as specified in § 63.8420(e)).

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

(5) At all times, maintain the monitoring equipment including, but not limited to, maintaining necessary parts for routine repairs of the monitoring equipment.

(b) For each liquid flow measurement device, you must meet the requirements in paragraphs (a)(1) through (5) and paragraphs (b)(1) through (3) of this section.

(1) Locate the flow sensor in a position that provides a representative flowrate.

(2) Use a flow sensor with a minimum measurement sensitivity of 2 percent of the liquid flowrate.

(3) At least semiannually, conduct a flow sensor calibration check.

(c) For each pressure measurement device, you must meet the requirements in paragraphs (a)(1) through (5) and paragraphs (c)(1) through (7) of this section.

(1) Locate the pressure sensor(s) in or as close to 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 measurement sensitivity of 0.5 inch of water or a transducer with a minimum measurement sensitivity of 1 percent of the pressure range.

(4) Check the pressure tap daily to ensure that it is not plugged.

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

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

(7) At least monthly, inspect all components for integrity, all electrical connections for continuity, and all mechanical connections for leakage.

(d) For each pH measurement device, you must meet the requirements in paragraphs (a)(1) through (5) and paragraphs (d)(1) through (4) of this section.

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

(4) At least monthly, inspect all components for integrity and all electrical connections for continuity.

(e) For each bag leak detection system, you must meet the requirements in paragraphs (e)(1) through (11) of this section.

(1) Each triboelectric bag leak detection system must be installed, calibrated, operated, and maintained according to the ''Fabric Filter Bag Leak Detection Guidance,'' (EPA–454/R–98–015, September 1997). This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality Planning and Standards; Emissions, Monitoring and Analysis Division; Emission Measurement Center (MD–19), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Continuous Emission Monitoring. Other types of bag leak detection systems must be installed, operated, calibrated, and maintained in a manner consistent with the manufacturer's written specifications and recommendations.

(2) The bag leak detection system must be certified by the manufacturer to be capable of detecting PM emissions at concentrations of 10 milligrams per actual cubic meter (0.0044 grains per actual cubic foot) or less.

(3) The bag leak detection system sensor must provide an output of relative PM loadings.

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

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

(6) For positive pressure fabric filter systems, a bag leak detector must be installed in each baghouse compartment or cell.

(7) For negative pressure or induced air fabric filters, the bag leak detector must be installed downstream of the fabric filter.

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

(9) The baseline output must be established by adjusting the range and the averaging period of the device and establishing the alarm set points and the alarm delay time according to section 5.0 of the "Fabric Filter Bag Leak Detection Guidance."

(10) Following initial adjustment of the system, the sensitivity or range, averaging period, alarm set points, or alarm delay time may not be adjusted except as detailed in your OM&M plan. In no case may the sensitivity be increased by more than 100 percent or decreased more than 50 percent over a 365-day period unless such adjustment follows a complete fabric filter inspection that demonstrates that the fabric filter is in good operating condition. Record each adjustment.

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

(f) For each lime or chemical feed rate measurement device, you must meet the requirements in paragraphs (a)(1) through (5) and paragraphs (f)(1) and (2) of this section.

(1) Locate the measurement device in a position that provides a representative feed rate measurement.

(2) At least semiannually, conduct a calibration check.

(g) For each limestone feed system on a DLA, you must meet the requirements in paragraphs (a)(1),(4), and (5) of this section and must ensure on a monthly basis that the feed system replaces limestone at least as frequently as the schedule set during the performance test.

(h) Requests for approval of alternate monitoring procedures must meet the requirements in §§ 63.8445(i) and 63.8(f).

§ 63.8455 How do I demonstrate initial compliance with the emission limitations?

(a) You must demonstrate initial compliance with each emission limitation that applies to you according to Table 4 to this subpart.

(b) You must establish each site-specific operating limit in Table 2 to this subpart that applies to you according to the requirements in § 63.8445 and Table 3 to this subpart.

(c) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in § 63.8480(e).

Continuous Compliance Requirements

§ 63.8465 How do I monitor and collect data to demonstrate continuous compliance?

(a) You must monitor and collect data according to this section.

(b) Except for periods of 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. This includes periods of startup, shutdown, malfunction, and routine control device maintenance as specified in § 63.8420(e) when the affected source is operating.

(c) You may not use data recorded during monitoring malfunctions, associated repairs, out-of-control periods, or required quality assurance or control activities for purposes of calculating data averages. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions. You must use all the valid data collected during all other periods in assessing compliance. Any averaging period for which you do not have valid monitoring data and such data are required constitutes a deviation from the monitoring requirements.

§ 63.8470 How do I demonstrate continuous compliance with the emission limitations?

(a) You must demonstrate continuous compliance with each emission limit and operating limit in Tables 1 and 2 to this subpart that applies to you according to the methods specified in Table 5 to this subpart.

(b) For each affected kiln that is equipped with an APCD that is not addressed in Table 2 to this subpart, or that is using process changes as a means of meeting the emission limits in Table 1 to this subpart, you must demonstrate continuous compliance with each emission limit in Table 1 to this subpart, and each operating limit established as required in § 63.8445(i)(2) according to the methods specified in your approved alternative monitoring procedures request, as described in §§ 63.8445(i)(1) and 63.8(f).

(c) You must report each instance in which you did not meet each emission limit and each operating limit in this subpart that applies to you. This includes periods of startup, shutdown, malfunction, and routine control device maintenance. These instances are deviations from the emission limitations in this subpart. These deviations must be reported according to the requirements in § 63.8485.

(d) During periods of startup, shutdown, and malfunction, you must operate according to your SSMP.

(e) 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 Administrator's satisfaction that you were operating according to an SSMP that satisfies the requirements of § 63.6(e) and your OM&M plan. The 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).

(f) Deviations that occur during periods of control device maintenance covered by an approved routine control device maintenance exemption according to § 63.8420(e) are not violations if you demonstrate to the Administrator's satisfaction that you were operating in accordance with the approved routine control device maintenance exemption.

(g) You must demonstrate continuous compliance with the operating limits in Table 2 to this subpart for visible emissions (VE) from tunnel kilns equipped with DLA, DIFF, or DLS/FF by monitoring VE at each kiln stack according to the requirements in paragraphs (g)(1) through (3) of this section.

(1) Perform daily VE observations of each kiln stack according to the procedures of Method 22 of 40 CFR part 60, appendix A. You must conduct the Method 22 test while the affected source is operating under normal conditions. The duration of each Method 22 test must be at least 15 minutes.

(2) If VE are observed during any daily test conducted using Method 22 of 40 CFR part 60, appendix A, you must promptly initiate and complete corrective actions according to your OM&M plan. If no VE are observed in 30 consecutive daily Method 22 tests for any kiln stack, you may decrease the frequency of Method 22 testing from daily to weekly for that kiln stack. If VE are observed during any weekly test, you must promptly initiate and complete corrective actions according to your OM&M plan, resume Method 22 testing of that kiln stack on a daily basis, and maintain that schedule until no VE are observed in 30 consecutive daily tests, at which time you may again decrease the frequency of Method 22 testing to a weekly basis.

(3) If VE are observed during any test conducted using Method 22 of 40 CFR part 60, appendix A, you must report these deviations by following the requirements in § 63.8485.

Notifications, Reports, and Records

§ 63.8480 What notifications must I submit and when?

(a) You must submit all of the notifications in §§ 63.7(b) and (c), 63.8(f)(4), and 63.9 (b) through (e), (g)(1), and (h) that apply to you, by the dates specified.

(b) As specified in § 63.9(b)(2) and (3), if you start up your affected source before May 16, 2003, you must submit an Initial Notification not later than 120 calendar days after May 16, 2003.

(c) As specified in § 63.9(b)(3), if you start up your new or reconstructed affected source on or after May 16, 2003, you must submit an Initial Notification not later than 120 calendar days after you become subject to this subpart.

(d) If you are required to conduct a performance test, you must submit a notification of intent to conduct a performance test at least 60 calendar days before the performance test is scheduled to begin, as required in § 63.7(b)(1).

(e) If you are required to conduct a performance test as specified in Table 3 to this subpart, you must submit a Notification of Compliance Status as specified in § 63.9(h) and paragraphs (e)(1) and (2) of this section.

(1) For each compliance demonstration that includes a performance test conducted according to the requirements in Table 3 to this subpart, you must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th calendar day following the completion of the performance test, according to § 63.10(d)(2).

(2) In addition to the requirements in § 63.9(h)(2)(i), you must include the information in paragraphs (e)(2)(i) and (ii) of this section in your Notification of Compliance Status.

(i) The operating limit parameter values established for each affected source with supporting documentation and a description of the procedure used to establish the values.

(ii) For each APCD that includes a fabric filter, if a bag leak detection system is used, analysis and supporting documentation demonstrating conformance with EPA guidance and specifications for bag leak detection systems in § 63.8450(e).

(f) If you request a routine control device maintenance exemption according to § 63.8420(e), you must submit your request for the exemption no later than 30 days before the compliance date.

§ 63.8485 What reports must I submit and when?

(a) You must submit each report in Table 6 to this subpart that applies to you.

(b) Unless the Administrator has approved a different schedule for submission of reports under § 63.10(a), you must submit each report by the date in Table 6 to this subpart and as specified 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 § 63.8395 and ending on June 30 or December 31, and lasting at least 6 months, but less than 12 months. For example, if your compliance date is March 1, then the first semiannual reporting period would begin on March 1 and end on December 31.

(2) The first compliance report must be postmarked or delivered no later than July 31 or January 31 for compliance periods ending on June 30 and December 31, respectively.

(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 for compliance periods ending on June 30 and December 31, respectively.

(5) For each affected source that is subject to permitting regulations pursuant to 40 CFR part 70 or 40 CFR part 71, 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 in paragraphs (c)(1) through (7) of this section.

(1) Company name and address.

(2) Statement by a responsible official with that official's name, title, and signature, certifying that, based on information and belief formed after reasonable inquiry, the statements and information in the report are true, accurate, and complete.

(3) Date of report and beginning and ending dates of the reporting period.

(4) If you had a startup, shutdown or malfunction during the reporting period and you took actions consistent with your SSMP and OM&M plan, the compliance report must include the information specified in § 63.10(d)(5)(i).

(5) A description of control device maintenance performed while the control device was offline and the kiln controlled by the control device was operating, including the information specified in paragraphs (c)(5)(i) through (iii) of this section.

(i) The date and time when the control device was shutdown and restarted.

(ii) Identification of the kiln that was operating and the number of hours that the kiln operated while the control device was offline.

(iii) A statement of whether or not the control device maintenance was included in your approved routine control device maintenance exemption developed as specified in § 63.8420(e). If the control device maintenance was included in your approved routine control device maintenance exemption, then you must report the information in paragraphs (c)(5)(iii)(A) through (C) of this section.

(A) The total amount of time that the kiln controlled by the control device operated during the current semiannual compliance period and during the previous semiannual compliance period.

(B) The amount of time that each kiln controlled by the control device operated while the control device was offline for maintenance covered under the routine control device maintenance exemption during the current semiannual compliance period and during the previous semiannual compliance period.

(C) Based on the information recorded under paragraphs (c)(5)(iii)(A) and (B) of this section, compute the annual percent of kiln operating uptime during which the control device was offline for routine maintenance using Equation 1 of this section.

$$RM = \frac{DT_p + DT_c}{KU_p + KU_c}(100) \qquad \text{(Eq. 1)}$$

Where:

RM=Annual percentage of kiln uptime during which control device was offline for routine control device maintenance

DT_p=Control device downtime claimed under the routine control device maintenance exemption for the previous semiannual compliance period

DT_c=Control device downtime claimed under the routine control device maintenance exemption for the current semiannual compliance period

KU_p=Kiln uptime for the previous semiannual compliance period
KU_c=Kiln uptime for the current semiannual compliance period

(6) If there are no deviations from any emission limitations (emission limits or operating limits) that apply to you, the compliance report must contain a statement that there were no deviations from the emission limitations during the reporting period.

(7) If there were no periods during which the CMS was out-of-control as specified in your OM&M plan, the compliance report must contain a statement that there were no periods during which the CMS was out-of-control during the reporting period.

(d) For each deviation from an emission limitation (emission limit or operating limit) that occurs at an affected source where you are not using a CMS to comply with the emission limitations in this subpart, the compliance report must contain the information in paragraphs (c)(1) through (5) and paragraphs (d)(1) and (2) of this section. This includes periods of startup, shutdown, malfunction, and routine control device maintenance.

(1) The total operating time of each affected source during the reporting period.

(2) Information on the number, duration, and cause of deviations (including unknown cause, if applicable), as applicable, and the corrective action taken.

(e) For each deviation from an emission limitation (emission limit or operating limit) occurring at an affected source where you are using a CMS to comply with the emission limitations in this subpart, you must include the information in paragraphs (c)(1) through (5) and paragraphs (e)(1) through (13) of this section. This includes periods of startup, shutdown, malfunction, and routine control device maintenance.

(1) The total operating time of each affected source during the reporting period.

(2) The date and time that each malfunction started and stopped.

(3) The date and time that each CMS was inoperative, except for zero (low-level) and high-level checks.

(4) The date, time, and duration that each CMS was out-of-control, including the pertinent information in your OM&M plan.

(5) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of startup, shutdown, or malfunction; during routine control device maintenance covered in your approved routine control device maintenance exemption; or during another period.

(6) A description of corrective action taken in response to a deviation.

(7) 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.

(8) A breakdown of the total duration of the deviations during the reporting period into those that were due to startup, shutdown, control equipment problems, process problems, other known causes, and other unknown causes.

(9) A summary of the total duration of CMS 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.

(10) A brief description of the process units.

(11) A brief description of the CMS.

(12) The date of the latest CMS certification or audit.

(13) A description of any changes in CMS, processes, or control equipment since the last reporting period.

(f) If you have obtained a title V operating permit according to 40 CFR part 70 or 40 CFR part 71, you 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 you submit a compliance report according to Table 6 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 limitation (including any operating limit), then submitting the compliance report will satisfy any obligation to report the same deviations in the semiannual monitoring report. However, submitting a compliance report will not otherwise affect any obligation you may have to report deviations from permit requirements to the permitting authority.

§ 63.8490 What records must I keep?

(a) You must keep the records listed in paragraphs (a)(1) through (4) 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 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 as required in § 63.10(b)(2)(viii).

(4) Records relating to control device maintenance and documentation of your approved routine control device maintenance exemption, if you request such an exemption under § 63.8420(e).

(b) You must keep the records required in Table 5 to this subpart to show continuous compliance with each emission limitation that applies to you.

(c) You must also maintain the records listed in paragraphs (c)(1) through (6) of this section.

(1) For each bag leak detection system, records of each alarm, the time of the alarm, the time corrective action was initiated and completed, and a brief description of the cause of the alarm and the corrective action taken.

(2) For each deviation of an operating limit parameter value, the date, time, and duration of the deviation, a brief explanation of the cause of the deviation and the corrective action taken, and whether the deviation occurred during a period of startup, shutdown, or malfunction.

(3) For each affected source, records of production rates on a fired-product basis.

(4) Records for any approved alternative monitoring or test procedures.

(5) Records of maintenance and inspections performed on the APCD.

(6) Current copies of your SSMP and OM&M plan, including any revisions, with records documenting conformance.

§ 63.8495 In what form and for 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 onsite 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 may keep the records offsite for the remaining 3 years.

Other Requirements and Information

§ 63.8505 What parts of the General Provisions apply to me?

Table 7 to this subpart shows which parts of the General Provisions in §§ 63.1 through 63.15 apply to you.

§ 63.8510 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by us, the U.S. EPA, or a delegated authority such as your State, local, or tribal agency. If the U.S. EPA Administrator has delegated authority to your State, local, or tribal agency, then that agency, in addition to the U.S. EPA, has the authority to implement and enforce this subpart. You should contact your U.S. EPA Regional Office to find out if implementation and enforcement of 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 section 40 CFR part 63, subpart E, the authorities contained in paragraph (c) of this section are retained by the Administrator of the U.S. EPA and are not transferred to the State, local, or tribal agency.

(c) The authorities that cannot be delegated to State, local, or tribal agencies are as specified in paragraphs (c)(1) through (4) of this section.

(1) Approval of alternatives to the applicability requirements in §§ 63.8385 and 63.8390, the compliance date requirements in § 63.8395, and the non-opacity emission limitations in § 63.8405.

(2) Approval of major changes to test methods under § 63.7(e)(2)(ii) and (f) and as defined in § 63.90.

(3) Approval of major changes to monitoring under § 63.8(f) and as defined in § 63.90.

(4) Approval of major changes to recordkeeping and reporting under § 63.10(f) and as defined in § 63.90.

§ 63.8515 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act, in § 63.2, and in this section as follows:

Air pollution control device (APCD) means any equipment that reduces the quantity of a pollutant that is emitted to the air.

Bag leak detection system means an instrument that is capable of monitoring PM loadings in the exhaust of a fabric filter in order to detect bag failures. A bag leak detection system includes, but is not limited to, an instrument that operates on triboelectric, light-scattering, light-transmittance, or other effects to monitor relative PM loadings.

Brick and structural clay products (BSCP) manufacturing facility means a plant site that manufactures brick (including, but not limited to, face brick, structural brick, and brick pavers); clay pipe; roof tile; extruded floor and wall tile; and/or other extruded, dimensional clay products. Brick and structural clay products manufacturing facilities typically process raw clay and shale, form the processed materials into bricks or shapes, and dry and fire the bricks or shapes.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limitation (including any operating limit) or work practice standard;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limitation (including any operating limit) or work practice standard in this subpart during startup, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

Dry lime injection fabric filter (DIFF) means an APCD that includes continuous injection of hydrated lime or other sorbent into a duct or reaction chamber followed by a fabric filter.

Dry lime scrubber/fabric filter (DLS/FF) means an APCD that includes continuous injection of humidified hydrated lime or other sorbent into a reaction chamber followed by a fabric filter. These systems typically include recirculation of some of the sorbent.

Dry limestone adsorber (DLA) means an APCD that includes a limestone storage bin, a reaction chamber that is essentially a packed tower filled with limestone, and may or may not include a peeling drum that mechanically scrapes reacted limestone to regenerate the stone for reuse.

Emission limitation means any emission limit or operating limit.

Fabric filter means an APCD used to capture PM by filtering a gas stream through filter media; also known as a baghouse.

Initial startup means:

(1) For a new or reconstructed tunnel kiln controlled with a DLA, and for a tunnel kiln that would be considered reconstructed but for § 63.8390(i)(1) or § 63.8390(i)(2), the time at which the temperature in the kiln first reaches 260 °C (500 °F) and the kiln contains product; or

(2) For a new or reconstructed tunnel kiln controlled with a DIFF, DLS/FF, or WS, the time at which the kiln first reaches a level of production that is equal to 75 percent of the kiln design capacity or 12 months after the affected source begins firing BSCP, whichever is earlier.

Kiln exhaust process stream means the portion of the exhaust from a tunnel kiln that exhausts directly to the atmosphere (or to an APCD), rather than to a sawdust dryer.

Large tunnel kiln means a tunnel kiln (existing, new, or reconstructed) with a design capacity equal to or greater than 9.07 Mg/hr (10 tph) of fired product.

Particulate matter (PM) means, for purposes of this subpart, emissions of PM that serve as a measure of total particulate emissions, as measured by Method 5 (40 CFR part 60, appendix A), and as a surrogate for metal HAP contained in the particulates including, but not limited to, antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, mercury, nickel, and selenium.

Plant site means all contiguous or adjoining property that is under common control, including properties that are separated only by a road or other public right-of-way. Common control includes properties that are owned, leased, or operated by the same entity, parent entity, subsidiary, or any combination thereof.

Research and development kiln means any kiln whose purpose is to conduct research and development for new processes and products and is not engaged in the manufacture of products for commercial sale, except in a de minimis manner.

Responsible official means responsible official as defined in 40 CFR 70.2.

Small tunnel kiln means a tunnel kiln (existing, new, or reconstructed) with a design capacity less than 9.07 Mg/hr (10 tph) of fired product.

Startup means the setting in operation of an affected source and starting the production process.

Tunnel kiln means any continuous kiln that is used to fire BSCP. Some tunnel kilns have two process streams, including a process stream that exhausts directly to the atmosphere or to an APCD, and a process stream in which the kiln exhaust is ducted to a sawdust dryer where it is used to dry sawdust before being emitted to the atmosphere.

Tunnel kiln design capacity means the maximum amount of brick, in Mg (tons), that a kiln is designed to produce in one year divided by the number of hours in a year (8,760 hours). If a kiln is modified to increase the capacity, the design capacity is considered to be the capacity following modifications.

Wet scrubber (WS) means an APCD that uses water, which may include caustic additives or other chemicals, as the sorbent. Wet scrubbers may use any of various design mechanisms to increase the contact between exhaust gases and the sorbent.

Tables to Subpart JJJJJ of Part 63

As stated in § 63.8405, you must meet each emission limit in the following table that applies to you:

TABLE 1 TO SUBPART JJJJJ OF PART 63.—EMISSION LIMITS

For each . . .	You must meet the following emission limits . . .	Or you must comply with the following . . .
1. Existing large tunnel kiln (design capacity ≥10 tph of fired product), excluding any process stream that is ducted to a sawdust dryer prior to July 22, 2002; or including any process stream that exhausts directly to the atmosphere or to an APCD and any process stream that is first ducted to a sawdust on or after July 22, 2002; each new or reconstructed small tunnel kiln (design capacity <10 tph of fired product), including all process streams; each tunnel kiln that would be considered reconstructed but for § 63.8390(i)(1), including all process streams; and each large tunnel kiln previously equipped with a DLA that would be considered reconstructed but for § 63.8390(i)(2), including all process streams.	a. HF emissions must not exceed 0.029 kilograms per megagram (kg/Mg) (0.057 pounds per ton (lb/ton)) of fired product. b. HCl emissions must not exceed 0.13 kg/Mg (0.26 lb/ton) of fired product. c. PM emissions must not exceed 0.21 kg/Mg (0.42 lb/ton) of fired product.	Reduce uncontrolled HF emissions by at least 90 percent. Reduce uncontrolled HCl emissions by at least 30 percent. Not applicable.
2. New or reconstructed large tunnel kiln, including all process streams.	a. HF emissions must not exceed 0.029 kg/Mg (0.057 lb/ton) of fired product. b. HCl emissions must not exceed 0.028 kg/Mg (0.056 lb/ton) of fired product. c. PM emissions must not exceed 0.060 kg/Mg (0.12 lb/ton) of fired product.	Reduce uncontrolled HF emissions by at least 90 percent. Reduce uncontrolled HCl emissions by at least 85 percent. Not applicable.

As stated in § 63.8405, you must meet each operating limit in the following table that applies to you:

TABLE 2 TO SUBPART JJJJJ OF PART 63.—OPERATING LIMITS

For each . . .	You must . . .
1. Kiln equipped with a DLA	a. Maintain the average pressure drop across the DLA for each 3-hour block period at or above the average pressure drop established during the performance test; and b. Maintain an adequate amount of limestone in the limestone hopper, storage bin (located at the top of the DLA), and DLA at all times; maintain the limestone feeder setting at or above the level established during the performance test; and c. Use the same grade of limestone from the same source as was used during the performance test; maintain records of the source and grade of limestone; and d. Maintain no VE from the DLA stack.
2. Kiln equipped with a DIFF or DLS/FF	a. If you use a bag leak detection system, initiate corrective action within 1 hour of a bag leak detection system alarm and complete corrective actions in accordance with your OM&M plan; 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 block reporting period; or maintain no VE from the DIFF or DLS/FF stack; and b. Maintain free-flowing lime in the feed hopper or silo and to the APCD at all times for continuous injection systems; maintain the feeder setting at or above the level established during the performance test for continuous injection systems.
3. Kiln equipped with a WS	a. Maintain the average scrubber pressure drop for each 3-hour block period at or above the average pressure drop established during the performance test; and b. Maintain the average scrubber liquid pH for each 3-hour block period at or above the average scrubber liquid pH established during the performance test; and c. Maintain the average scrubber liquid flow rate for each 3-hour block period at or above the average scrubber liquid flow rate established during the performance test; and d. If chemicals are added to the scrubber water, maintain the average scrubber chemical feed rate for each 3-hour block period at or above the average scrubber chemical feed rate established during the performance test.

As stated in § 63.8445, you must conduct each performance test in the following table that applies to you:

TABLE 3 TO SUBPART JJJJJ OF PART 63.—REQUIREMENTS FOR PERFORMANCE TESTS

For each . . .	You must . . .	Using . . .	According to the following requirements . . .
1. Kiln	a. Select locations of sampling ports and the number of traverse points.	Method 1 or 1A of 40 CFR part 60, appendix A.	Sampling sites must be located at the outlet of the APCD and prior to any releases to the atmosphere for all affected sources. If you choose to meet the percent emission reduction requirements for HF or HCl, a sampling site must also be located at the APCD inlet.
	b. Determine velocities and volumetric flow rate.	Method 2 of 40 CFR part 60, appendix A.	You may use Method 2A, 2C, 2D, 2F, or 2G of 40 CFR part 60, appendix A, as appropriate, as an alternative to using Method 2 of 40 CFR part 60, appendix A.
	c. Conduct gas molecular weight analysis.	Method 3 of 40 CFR part 60, appendix A.	You may use Method 3A or 3B of 40 CFR part 60, appendix A, as appropriate, as an alternative to using Method 3 of 40 CFR part 60, appendix A.
	d. Measure moisture content of the stack gas.	Method 4 of 40 CFR part 60, appendix A.	
	e. Measure HF and HCl emissions.	Method 26A of 40 CFR part 60, appendix A; or	Conduct the test while operating at the maximum production level. You may use Method 26 of 40 CFR part 60, appendix A, as an alternative to using Method 26A of 40 CFR part 60, appendix A, when no acid PM (*e.g.,* HF or HCl dissolved in water droplets emitted by sources controlled by a WS) is present.
		Method 320 of 40 CFR part 63, appendix A.	Conduct the test while operating at the maximum production level. When using Method 320 of 40 CFR part 63, appendix A, you must follow the analyte spiking procedures of section 13 of Method 320 of 40 CFR part 63, appendix A, unless you can demonstrate that the complete spiking procedure has been conducted at a similar source.
	f. Measure PM emissions.	Method 5 of 40 CFR part 60, appendix A.	Conduct the test while operating at the maximum production level.
2. Kiln that is complying with production-based emission limits.	Determine the production rate during each test run in order to determine compliance with production-based emission limits.	Production data collected during the performance tests (*e.g.*, no. of pushes per hour, no. of bricks per kiln car, weight of a typical fired brick).	You must measure and record the production rate, on a fired-product basis, of the affected source for each of the three test runs.
3. Kiln equipped with a DLA	a. Establish the operating limit for the average pressure drop across the DLA.	Data from the pressure drop measurement device during the performance test.	You must continuously measure the pressure drop across the DLA, determine and record the block average pressure drop values for the three test runs, and determine and record the 3-hour block average of the recorded pressure drop measurements for the three test runs.

TABLE 3 TO SUBPART JJJJJ OF PART 63.—REQUIREMENTS FOR PERFORMANCE TESTS—Continued

For each . . .	You must . . .	Using . . .	According to the following requirements . . .
	b. Establish the operating limit for the limestone feeder setting.	Data from the limestone feeder during the performance test.	You must ensure that you maintain an adequate amount of limestone in the limestone hopper, storage bin (located at the top of the DLA), and DLA at all times during the performance test. You must establish your limestone feeder setting one week prior to the performance test and maintain the feeder setting for the one-week period that precedes the performance test and during the performance test.
	c. Document the source and grade of limestone used.	Records of limestone purchase.	
4. Kiln equipped with a DIFF or DLS/FF.	Establish the operating limit for the lime feeder setting.	Data from the lime feeder during the performance test.	For continuous lime injection systems, you must ensure that lime in the feed hopper or silo and to the APCD is free-flowing at all times during the performance test and record the feeder setting for the three test runs. If the feed rate setting varies during the three test runs, determine and record the average feed rate from the three test runs.
5. Kiln equipped with a WS	a. Establish the operating limit for the average scrubber pressure drop.	Data from the pressure drop measurement device during the performance test.	You must continuously measure the scrubber pressure drop, determine and record the block average pressure drop values for the three test runs, and determine and record the 3-hour block average of the recorded pressure drop measurements for the three test runs.
	b. Establish the operating limit for the average scrubber liquid pH.	Data from the pH measurement device during the performace test.	You must continuously measure the scrubber liquid pH, determine and record the block average pH values for the three test runs, and determine and record the 3-hour block average of the recorded pH measurements for the three test runs.
	c. Establish the operating limit for the average scrubber liquid flow rate.	Data from the flow rate measurement device during the performance test.	You must continuously measure the scrubber liquid flow rate, determine and record the block average flow rate values for the three test runs, and determine and record the 3-hour block average of the recorded flow rate measurements for the three test runs.
6. Kiln equipped with a WS that includes chemical addition to the water.	Establish the operating limit for the average scrubber chemical feed rate.	Data from the chemical feed rate measurement device during the performance test.	You must continuously measure the scrubber chemical feed rate, determine and record the block average chemical feed rate values for the three test runs, and determine and record the 3-hour block average of the recorded chemical feed rate measurements for the three test runs.

As stated in § 63.8455, you must demonstrate initial compliance with each emission limitation that applies to you according to the following table:

Table 4 to Subpart JJJJJ of Part 63.—Initial Compliance with Emission Limitations

For each . . .	For the following emission limitation . . .	You have demonstrated initial compliance if . . .
1. Existing large tunnel kiln (design capacity ≥10 tph of fired product), excluding any process stream that is ducted to a sawdust dryer prior to July 22, 2002; or including any process stream that exhausts directly to the atmosphere or to an APCD and any process stream that is first ducted to a sawdust dryer on or after July 22, 2002; each new or reconstructed small tunnel kiln (design capacity <10 tph of fired product), including all process streams; each tunnel kiln that would be considered reconstructed but for § 63.8390(i)(1), including all process streams; and each large tunnel kiln previously equipped with a DLA that would be considered reconstructed but for § 63.8390(i)(2), including all process streams.	a. HF emissions must not exceed 0.029 kg/Mg (0.057 lb/ton) of fired product; or uncontrolled HF emissions must be reduced by at least 90 percent; and	i. The HF emissions measured using Method 26A of 40 CFR part 60, appendix A or Method 320 of 40 CFR part 63, appendix A over the period of the initial performance test, according to the calculations in § 63.8445(g)(1), do not exceed 0.029 kg/Mg (0.057 lb/ton); or uncontrolled HF emissions measured using Method 26A of 40 CFR part 60, appendix A or Method 320 of 40 CFR part 63, appendix A over the period of the initial performance test are reduced by at least 90 percent, according to the calculations in § 63.8445(g)(2); and ii. You establish and have a record of the operating limits listed in Table 2 to this subpart over the 3-hour performance test during which HF emissions did not exceed 0.029 kg/Mg (0.057 lb/ton) or uncontrolled HF emissions were reduced by at least 90 percent.
	b. HCl emissions must not exceed 0.13 kg/Mg (0.26 lb/ton) of fired product; or uncontrolled HCl emissions must be reduced by at least 30 percent; and	i. The HCl emissions measured using Method 26A of 40 CFR part 60, appendix A or Method 320 of 40 CFR part 63, appendix A over the period of the initial performance test, according to the calculations in § 63.8445(g)(1), do not exceed 0.13 kg/Mg (0.26 lb/ton); or uncontrolled HCl emissions measured using Method 26A of 40 CFR part 60, appendix A or Method 320 of 40 CFR part 63, appendix A over the period of the initial performance test are reduced by at least 30 percent, according to the calculations in § 63.8445(g)(2); and ii. You establish and have a record of the operating limits listed in Table 2 to this subpart over the 3-hour performance test during which HCl emissions did not exceed 0.13 kg/Mg (0.26 lb/ton) or uncontrolled HCl emissions were reduced by at least 30 percent.
	c. PM emissions must not exceed 0.21 kg/Mg (0.42 lb/ton) of fired product.	i. The PM emissions measured using Method 5 of 40 CFR part 60, appendix A, over the period of the initial performance test, according to the calculations in § 63.8445(g)(1), do not exceed 0.21 kg/Mg (0.42 lb/ton); and ii. You establish and have a record of the operating limits listed in Table 2 to this subpart over the 3-hour performance test during which PM emissions did not exceed 0.21 kg/Mg (0.42 lb/ton).
2. New or reconstructed large tunnel kiln, including all process streams.	a. HF emissions must not exceed 0.029 kg/Mg (0.057 lb/ton) of fired product; or uncontrolled HF emissions must be reduced by at least 90 percent; and	i. The HF emissions measured using Method 26A of 40 CFR part 60, appendix A or Method 320 of 40 CFR part 63, appendix A over the period of the initial performance test, according to the calculations in § 63.8445(g)(1), do not exceed 0.029 kg/Mg (0.057 lb/ton); or uncontrolled HF emissions measured using Method 26A of 40 CFR part 60, appendix A or Method 320 of 40 CFR part 63, appendix A over the period of the initial performance test are reduced by at least 90 percent, according to the calculations in § 63.8445(g)(2); and

TABLE 4 TO SUBPART JJJJJ OF PART 63.—INITIAL COMPLIANCE WITH EMISSION LIMITATIONS—Continued

For each . . .	For the following emission limitation . . .	You have demonstrated initial compliance if . . .
		ii. You establish and have a record of the operating limits listed in Table 2 to this subpart over the 3-hour performance test during which HF emissions did not exceed 0.029 kg/Mg (0.057 lb/ton) or uncontrolled HF emissions were reduced by at least 90 percent.
	b. HCl emissions must not exceed 0.028 kg/Mg (0.056 lb/ton) of fired product; or uncontrolled HCl emissions must be reduced by at least 85 percent; and	i. The HCl emissions measured using Method 26A of 40 CFR part 60, appendix A or Method 320 of 40 CFR part 63, appendix A over the period of the initial performance test, according to the calculations in § 63.8445(g)(1), do not exceed 0.028 kg/Mg (0.056 lb/ton); or uncontrolled HCl emissions measured using Method 26A of 40 CFR part 60, appendix A or Method 320 of 40 CFR part 63, appendix A over the period of the initial performance test are reduced by at least 85 percent, according to the calculations in § 63.8445(g)(2); and ii. You establish and have a record of the operating limits listed in Table 2 to this subpart over the 3-hour performance test during which HCl emissions did not exceed 0.028 kg/Mg (0.056 lb/ton) or uncontrolled HCl emissions were reduced by at least 85 percent.
	c. PM emissions must not exceed 0.060 kg/Mg (0.12 lb/ton) of fired product.	i. The PM emissions measured using Method 5 of 40 CFR part 60, appendix A, over the period of the initial performance test, according to the calculations in § 63.8445(g)(1), do not exceed 0.060 kg/Mg (0.12 lb/ton); and ii. You establish and have a record of the operating limits listed in Table 2 to this subpart over the 3-hour performance test during which PM emissions did not exceed 0.060 kg/Mg (0.12 lb/ton).

As stated in § 63.8470, you must demonstrate continuous compliance with each emission limit and operating limit that applies to you according to the following table:

TABLE 5 TO SUBPART JJJJJ OF PART 63.—CONTINUOUS COMPLIANCE WITH EMISSION LIMITS AND OPERATING LIMITS

For each . . .	For the following emission limits and operating limits . . .	You must demonstrate continuous compliance by . . .
1. Kiln equipped with a DLA	Each emission limit in Table 1 to this subpart and each operating limit in Item 1 of Table 2 to this subpart for kilns equipped with a DLA.	i. Collecting the DLA pressure drop data according to § 63.8450(a); reducing the DLA pressure drop data to 3-hour block averages according to § 63.8450(a); maintaining the average pressure drop across the DLA for each 3-hour block period at or above the average pressure drop established during the performance test; and ii. Verifying that the limestone hopper and storage bin (located at the top of the DLA) contain adequate limestone by performing a daily visual check; and iii. Recording the limestone feeder setting daily to verify that the feeder setting is being maintained at or above the level established during the performance test; and iv. Using the same grade of limestone from the same source as was used during the performance test; maintaining records of the source and type of limestone; and v. Performing VE observations of the DLA stack at the frequency specified in § 63.8470(g) using Method 22 of 40 CFR part 60, appendix A; maintaining no VE from the DLA stack.

TABLE 5 TO SUBPART JJJJJ OF PART 63.—CONTINUOUS COMPLIANCE WITH EMISSION LIMITS AND OPERATING LIMITS—Continued

For each . . .	For the following emission limits and operating limits . . .	You must demonstrate continuous compliance by . . .
2. Kiln equipped with a DIFF or DLS/FF.	Each emission limit in Table 1 to this subpart and each operating limit in Item 2 of Table 2 to this subpart for kilns equipped with DIFF or DLS/FF.	i. If you use a bag leak detection system, initiating corrective action within 1 hour of a bag leak detection system alarm and completing corrective actions in accordance with your OM&M plan; operating and maintaining the fabric filter such that the alarm is not engaged for more than 5 percent of the total operating time in a 6-month block reporting period; in calculating this operating time fraction, 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 is counted as a minimum of 1 hour; if you take longer than 1 hour to initiate corrective action, the alarm time is counted as the actual amount of time taken by you to initiate corrective action; or performing VE observations of the DIFF or DLS/FF stack at the frequency specified in § 63.8470(g) using Method 22 of 40 CFR part 60, appendix A; maintaining no VE from the DIFF or DLS/FF stack; and ii. Verifying that lime is free-flowing via a load cell, carrier gas/lime flow indicator, carrier gas pressure drop measurement system, or other system; recording all monitor or sensor output, and if lime is found not to be free flowing, promptly initiating and completing corrective actions in accordance with your OM&M plan; recording the feeder setting once during each shift of operation to verify that the feeder setting is being maintained at or above the level established during the performance test.
3. Kiln equipped with a WS	Each emission limit in Table 1 to this subpart and each operating limit in Item 3 of Table 2 to this subpart for kilns equipped with WS.	i. Collecting the scrubber pressure drop data according to § 63.8450(a); reducing the scrubber pressure drop data to 3-hour block averages according to § 63.8450(a); maintaining the average scrubber pressure drop for each 3-hour block period at or above the average pressure drop established during the performance test; and ii. Collecting the scrubber liquid pH data according to § 63.8450(a); reducing the scrubber liquid pH data to 3-hour block averages according to § 63.8450(a); maintaining the average scrubber liquid pH for each 3-hour block period at or above the average scrubber liquid pH established during the performance test; and iii. Collecting the scrubber liquid flow rate data according to § 63.8450(a); reducing the scrubber liquid flow rate data to 3-hour block averages according to § 63.8450(a); maintaining the average scrubber liquid flow rate for each 3-hour block period at or above the average scrubber liquid flow rate established during the performance test; and iv. If chemicals are added to the scrubber water, collecting the scrubber chemical feed rate data according to § 63.8450(a); reducing the scrubber chemical feed rate data to 3-hour block averages according to § 63.8450(a); maintaining the average scrubber chemical feed rate for each 3-hour block period at or above the average scrubber chemical feed rate established during the performance test.

As stated in § 63.8485, you must submit each report that applies to you according to the following table:

TABLE 6 TO SUBPART JJJJJ OF PART 63.—REQUIREMENTS FOR REPORTS

You must submit . . .	The report must contain . . .	You must submit the report . . .
1. A compliance report	a. If there are no deviations from any emission limitations (emission limits, operating limits) that apply to you, a statement that there were no deviations from the emission limitations during the reporting period. If there were no periods during which the CMS was out-of-control as specified in your OM&M plan, a statement that there were no periods during which the CMS was out- of-control during the reporting period.	Semiannually according to the requirements in § 63.8485(b).

TABLE 6 TO SUBPART JJJJJ OF PART 63.—REQUIREMENTS FOR REPORTS—Continued

You must submit . . .	The report must contain . . .	You must submit the report . . .
	b. If you have a deviation from any emission limitation (emission limit, operating limit) during the reporting period, the report must contain the information in § 63.8485(d) or (e). If there were periods during which the CMS was out-of-control, as specified in your OM&M plan, the report must contain the information in § 63.8485(e).	Semiannually according to the requirements in § 63.8485(b).
	c. 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).	Semiannually according to the requirements in § 63.8485(b).
2. An immediate startup, shutdown, and malfunction report if you took actions during a startup, shutdown, or malfunction during the reporting period that are not consistent with your SSMP.	a. Actions taken for the event according to the requirements in § 63.10(d)(5)(ii).	By fax or telephone within 2 working days after starting actions inconsistent with the plan.
	b. The information in § 63.10(d)(5)(ii)	By letter within 7 working days after the end of the event unless you have made alternative arrangements with the permitting authority.

As stated in § 63.8505, you must comply with the General Provisions in §§ 63.1 through 63.15 that apply to you according to the following table:

TABLE 7 TO SUBPART JJJJJ OF PART 63.—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART JJJJJ

Citation	Subject	Brief description	Applies to subpart JJJJJ
§ 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	Compliance date; circumvention; severability	Yes.
§ 63.5	Construction/Reconstruction	Applicability; applications; approvals	Yes.
§ 63.6(a)	Applicability	General Provisions (GP) apply unless compliance extension; 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 section 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 area sources.	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; for section 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; correct malfunctions as soon as practicable; 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 startup, shutdown, and malfunction (SSM) and SSMP; content of SSMP.	Yes.
§ 63.6(f)(1)	Compliance Except During SSM	You must 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)	Alternative Standard	Procedures for getting an alternative standard	Yes.
§ 63.6(h)	Opacity/VE Standards	Requirements for opacity and VE standards	No, not applicable.

TABLE 7 TO SUBPART JJJJJ OF PART 63.—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART JJJJJ—Continued

Citation	Subject	Brief description	Applies to subpart JJJJJ
§ 63.6(i)	Compliance Extension	Procedures and criteria for Administrator to grant compliance extension.	Yes.
§ 63.6(j)	Presidential Compliance Exemption	President may exempt source category	Yes.
§ 63.7(a)(1)–(2)	Performance Test Dates	Dates for conducting initial performance testing and other compliance demonstrations; must conduct 180 days after first subject to rule.	Yes.
§ 63.7(a)(3)	Section 114 Authority	Administrator may require a performance test under CAA section 114 at any time.	Yes.
§ 63.7(b)(1)	Notification of Performance Test	Must notify Administrator 60 days before the test	Yes.
§ 63.7(b)(2)	Notification of Rescheduling	Must notify Administrator 5 days before scheduled date of rescheduled date.	Yes.
§ 63.7(c)	Quality Assurance(QA)/Test Plan	Requirements; test plan approval procedures; performance audit requirements; 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.	Performance tests must be conducted under representative conditions.	No, § 63.8445 specifies requirements.
		Cannot conduct performance tests during SSM; not a violation to exceed standard during SSM.	Yes.
§ 63.7(e)(2)–(3)	Conditions for Conducting Performance Tests.	Must conduct according to subpart and EPA test methods unless Administrator approves alternative; must have at least three test runs of at least 1 hour each; compliance is based on arithmetic mean of three runs; conditions when data from an additional test run can be used.	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; must submit performance test data 60 days after end of test with the notification of compliance status.	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 subpart	Yes.
§ 63.8(a)(2)	Performance Specifications	Performance Specifications in appendix B of 40 CFR part 60 apply.	Yes.
§ 63.8(a)(3)	[Reserved].		
§ 63.8(a)(4)	Monitoring with Flares	Requirements for flares in § 63.11 apply	No, not applicable.
§ 63.8(b)(1)	Monitoring	Must conduct monitoring according to standard unless Administrator approves alternative.	Yes.
§ 63.8(b)(2)–(3)	Multiple Effluents and Multiple Monitoring Systems.	Specific requirements for installing and reporting on monitoring systems.	Yes.
§ 63.8(c)(1)	Monitoring System Operation and Maintenance.	Maintenance consistent with good air pollution control practices.	Yes.
§ 63.8(c)(1)(i)	Routine and Predictable SSM	Reporting requirements for SSM when action is described in SSMP.	Yes.
§ 63.8(c)(1)(ii)	SSM not in SSMP	Reporting requirements for SSM when action is not described in SSMP.	Yes.
§ 63.8(c)(1)(iii)	Compliance with Operation and Maintenance Requirements.	How Administrator determines if source complying with operation and maintenance requirements.	Yes.
§ 63.8(c)(2)–(3)	Monitoring System Installation	Must install to get representative emission and parameter measurements.	Yes.
§ 63.8(c)(4)	CMS Requirements	Requirements for CMS	No, §§ 63.8425 and 63.8465 specify requirements.
§ 63.8(c)(5)	Continuous Opacity Monitoring System (COMS) Minimum Procedures.	COMS minimum procedures	No, not applicable.
§ 63.8(c)(6)	CMS Requirements	Zero and high level calibration check requirements	No, § 63.8425 specifies requirements.
§ 63.8(c)(7)–(8)	CMS Requirements	Out-of-control periods	No, § 63.8425 specifies requirements.
§ 63.8(d)	CMS Quality Control	Requirements for CMS quality control	No, § 63.8425 specifies requirements.
§ 63.8(e)	CMS Performance Evaluation	Requirements for CMS performance evaluation	No, § 63.8425 specifies requirements.
§ 63.8(f)(1)–(5)	Alternative Monitoring Method	Procedures for Administrator to approve alternative monitoring.	Yes.

TABLE 7 TO SUBPART JJJJJ OF PART 63.—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART JJJJJ—Continued

Citation	Subject	Brief description	Applies to subpart JJJJJ
§ 63.8(f)(6)	Alternative to Relative Accuracy Test	Procedures for Administrator to approve alternative relative accuracy test for continuous emissions monitoring systems (CEMS).	No, not applicable.
§ 63.8(g)	Data Reduction	COMS and CEMS data reduction requirements	No, not applicable.
§ 63.9(a)	Notification Requirements	Applicability; State delegation	Yes.
§ 63.9(b)	Initial Notifications	Requirements for initial notifications	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	Yes.
§ 63.9(f)	Notification of VE/Opacity Test	Notify Administrator 30 days prior	No, not applicable.
§ 63.9(g)(1)	Additional Notifications When Using CMS.	Notification of performance evaluation	Yes.
§ 63.9(g)(2)–(3)	Additional Notifications When Using CMS.	Notification of COMS data use; notification that relative accuracy alternative criterion were exceeded.	No, not applicable.
§ 63.9(h)	Notification of Compliance Status	Contents; submittal requirements	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	Applicability; general information	Yes.
§ 63.10(b)(1)	General Recordkeeping Requirements	General requirements	Yes.
§ 63.10(b)(2)(i)–(v)	Records Related to SSM	Requirements for SSM records	Yes.
§ 63.10(b)(2)(vi)–(xii) and (xiv).	CMS Records	Records when CMS is malfunctioning, inoperative or out-of-control.	Yes.
§ 63.10(b)(2)(xiii)	Records	Records when using alternative to relative accuracy test	No, not applicable.
§ 63.10(b)(3)	Records	Applicability Determinations	Yes.
§ 63.10(c)(1)–(15)	Records	Additional records for CMS	No, §§ 63.8425 and 63.8490 specify requirements.
§ 63.10(d)(1) and (2).	General Reporting Requirements	Requirements for and reporting; performance test results reporting.	Yes.
§ 63.10(d)(3)	Reporting Opacity or VE Observations	Requirements for reporting opacity and VE	No, not applicable.
§ 63.10(d)(4)	Progress Reports	Must submit progress reports on schedule if under compliance extension.	Yes.
§ 63.10(d)(5)	SSM Reports	Contents and submission	Yes.
§ 63.10(e)(1)–(3)	Additional CMS Reports	Requirements for CMS reporting	No, §§ 63.8425 and 63.8485 specify requirements.
§ 63.10(e)(4)	Reporting COMS data	Requirements for reporting COMS data with performance test data.	No, not applicable.
§ 63.10(f)	Waiver for Recordkeeping/Reporting	Procedures for Administrator to waive	Yes.
§ 63.11	Flares	Requirement for flares	No, not applicable.
§ 63.12	Delegation	State authority to enforce standards	Yes.
§ 63.13	Addresses	Addresses for reports, notifications, requests	Yes.
§ 63.14	Incorporation by Reference	Materials incorporated by reference	Yes.
§ 63.15	Availability of Information	Information availability; confidential information	Yes.

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

Subpart KKKKK—National Emission Standards for Hazardous Air Pollutants for Clay Ceramics Manufacturing

Sec.

What This Subpart Covers

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63.8535 Am I subject to this subpart?
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63.8560 What are my options for meeting the emission limitations and work practice standards?

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63.8590 When must I conduct subsequent performance tests?
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Continuous Compliance Requirements

63.8615 How do I monitor and collect data to demonstrate continuous compliance?
63.8620 How do I demonstrate continuous compliance with the emission limitations and work practice standards?

What This Subpart Covers

§ 63.8530 What is the purpose of this subpart?

This subpart establishes national emission limitations and work practice standards for hazardous air pollutants (HAP) emitted from clay ceramics manufacturing facilities. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and work practice standards.

§ 63.8535 Am I subject to this subpart?

You are subject to this subpart if you own or operate a clay ceramics manufacturing facility that is, is located at, or is part of a major source of HAP emissions according to the criteria in paragraphs (a) and (b) of this section.

(a) A clay ceramics manufacturing facility is a plant site that manufactures pressed floor tile, pressed wall tile, other pressed tile, or sanitaryware (*e.g.*, sinks and toilets). Clay ceramics manufacturing facilities typically process clay, shale, and various additives; form the processed materials into tile or sanitaryware shapes; and dry and fire the ceramic products. Glazes are applied to many tile and sanitaryware products.

(b) A major source of HAP emissions is any stationary source or group of stationary sources within a contiguous area under common control that emits or has the potential to emit any single HAP at a rate of 9.07 megagrams (10 tons) or more per year or any combination of HAP at a rate of 22.68 megagrams (25 tons) or more per year.

§ 63.8540 What parts of my plant does this subpart cover?

(a) This subpart applies to each existing, new, or reconstructed affected source at a clay ceramics manufacturing facility and to each affected source described in paragraphs (f)(1) or (f)(2) of this section.

(b) Each existing, new, or reconstructed periodic kiln, tunnel kiln, and roller kiln is an affected source regardless of design capacity. Each source that meets the description in paragraphs (f)(1) or (f)(2) also is an affected source.

(c) Kilns that are used exclusively for research and development (R&D) and are not used to manufacture products for commercial sale, except in a *de minimis* manner, are not subject to the requirements of this subpart.

(d) Kilns that are used exclusively for setting glazes on previously fired products or for refiring are not subject to the requirements of this subpart.

(e) A source is a new affected source if construction of the affected source began after July 22, 2002, and you met the applicability criteria at the time you began construction.

(f) An affected source is reconstructed if you meet the criteria as defined in § 63.2, except as provided in paragraphs (f)(1) and (f)(2) of this section.

(1) It is not technologically and economically feasible for an existing tunnel kiln whose design capacity is less than 9.07 megagrams per hour (Mg/hr) (10 tons per hour (tph)) of fired product but is increased such that it is equal to or greater than 9.07 Mg/hr (10 tph) of fired product to meet the relevant standards (*i.e.*, new source maximum achievable control technology (MACT)) by retrofitting with a dry lime injection fabric filter (DIFF), dry lime scrubber/fabric filter (DLS/FF), or wet scrubber (WS).

(2) It is not technologically and economically feasible for an existing dry limestone adsorber (DLA)-controlled kiln whose design capacity is equal to or greater than 9.07 Mg/hr (10 tph) of fired product to meet the relevant standards by retrofitting with a DIFF, DLS/FF, or WS.

(g) An affected source is existing if it is not new or reconstructed and does not meet the descriptions provided in paragraphs (f)(1) and (f)(2) of this section.

§ 63.8545 When do I have to comply with this subpart?

(a) If you have a new or reconstructed affected source or an affected source described in § 63.8540(f)(1) or § 63.8540(f)(2), you must comply with this subpart according to paragraphs (a)(1) and (2) of this section.

(1) If the initial startup of your affected source is before May 16, 2003, then you must comply with the applicable emission limitations and work practice standards in Tables 1, 2, and 3 to this subpart no later than May 16, 2003.

(2) If the initial startup of your affected source is after May 16, 2003, then you must comply with the applicable emission limitations and work practice standards in Tables 1, 2, and 3 to this subpart upon initial startup of your affected source.

(b) If you have an existing affected source, you must comply with the work practice standards for existing sources in Table 3 to this subpart no later than May 16, 2003.

(c) If you have an existing area source that increases its emissions or its potential to emit such that it becomes a major source of HAP by adding a new affected source or by reconstructing, you must be in compliance with this subpart upon initial startup of your affected source as a major source.

(d) If you have a new area source (*i.e.*, an area source for which construction or reconstruction was commenced after July 22, 2002) that increases its emissions or its potential to emit such that it becomes a major source of HAP, you must be in compliance with this subpart upon initial startup of your affected source as a major source.

(e) You must meet the notification requirements in § 63.8630 according to the schedule in § 63.8630 and in 40 CFR part 63, subpart A. Some of the notifications must be submitted before you are required to comply with the emission limitations in this subpart.

Emission Limitations and Work Practice Standards

§ 63.8555 What emission limitations and work practice standards must I meet?

(a) You must meet each emission limit in Table 1 to this subpart that applies to you.

(b) You must meet each operating limit in Table 2 to this subpart that applies to you.

(c) You must meet each work practice standard in Table 3 to this subpart that applies to you.

§ 63.8560 What are my options for meeting the emission limitations and work practice standards?

(a) To meet the emission limitations in Tables 1 and 2 to this subpart, you must use one or more of the options listed in paragraphs (a)(1) and (2) of this section.

(1) *Emissions control system.* Use an emissions capture and collection system and an air pollution control device (APCD) and demonstrate that the resulting emissions or emissions reductions meet the emission limits in Table 1 to this subpart, and that the capture and collection system and APCD meet the applicable operating limits in Table 2 to this subpart.

(2) *Process changes.* Use low-HAP raw materials or implement manufacturing process changes and demonstrate that the resulting emissions or emissions reductions meet the emission limits in Table 1 to this subpart.

(b) To meet the work practice standards in Table 3 to this subpart, for each affected kiln, you must use natural gas, or an equivalent fuel (such as propane or other clean burning fuel), as the kiln fuel at all times except during periods of natural gas curtailment or other periods when natural gas is not available.

General Compliance Requirements

§ 63.8570 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limitations (including operating limits) in this subpart at all times, except during periods of startup, shutdown, and malfunction and during periods of routine control device maintenance as specified in paragraph (e) of this section.

(b) Except as specified in paragraph (e) of this section, 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). During the period between the compliance date specified for your affected source in § 63.8545 and the date upon which continuous monitoring systems (CMS) (*e.g.*, continuous parameter monitoring systems) have been installed and verified and any applicable operating limits have been set, you must maintain a log detailing the operation and maintenance of the process and emissions control equipment.

(c) For each kiln that is subject to the emission limits specified in Table 1 to this subpart, you must develop and implement a written startup, shutdown, and malfunction plan (SSMP) according to the provisions in § 63.6(e)(3).

(d) For each kiln that is subject to the emission limits specified in Table 1 to this subpart, you must prepare and implement a written operation, maintenance, and monitoring (OM&M) plan according to the requirements in § 63.8575.

(e) If you own or operate a kiln that is subject to the emission limits specified in Table 1 to this subpart and must perform routine maintenance on the control device for that kiln, you may bypass the kiln control device and continue operating the kiln upon approval by the Administrator provided you satisfy the conditions listed in paragraphs (e)(1) through (5) of this section.

(1) You must request a routine control device maintenance exemption from the Administrator. Your request must justify the need for the routine maintenance on the control device and the time required to accomplish the maintenance activities, describe the maintenance activities and the frequency of the maintenance activities, explain why the maintenance cannot be accomplished during kiln shutdowns, describe how you plan to minimize emissions to the greatest extent possible during the maintenance, and provide any other documentation required by the Administrator.

(2) The routine control device maintenance exemption must not exceed 4 percent of the annual operating uptime for each kiln.

(3) The request for the routine control device maintenance exemption, if approved by the Administrator, must be incorporated by reference in and attached to the affected source's title V permit.

(4) You must minimize HAP emissions during the period when the kiln is operating and the control device is offline.

(5) You must minimize the time period during which the kiln is operating and the control device is offline.

(f) You must be in compliance with the work practice standards in this subpart at all times, except during periods of natural gas curtailment or other periods when natural gas is not available.

(g) You must be in compliance with the provisions of subpart A of this part, except as noted in Table 8 to this subpart.

§ 63.8575 What do I need to know about operation, maintenance, and monitoring plans?

(a) For each kiln that is subject to the emission limits specified in Table 1 to this subpart, you must prepare, implement, and revise as necessary an OM&M plan that includes the information in paragraph (b) of this section. Your OM&M plan must be available for inspection by the permitting authority upon request.

(b) Your OM&M plan must include, as a minimum, the information in paragraphs (b)(1) through (13) of this section.

(1) Each process and APCD to be monitored, the type of monitoring device that will be used, and the operating parameters that will be monitored.

(2) A monitoring schedule that specifies the frequency that the parameter values will be determined and recorded.

(3) The limits for each parameter that represent continuous compliance with the emission limitations in § 63.8555. The limits must be based on values of the monitored parameters recorded during performance tests.

(4) Procedures for the proper operation and routine and long-term maintenance of each APCD, including a maintenance and inspection schedule that is consistent with the manufacturer's recommendations.

(5) Procedures for installing 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 APCD).

(6) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction system.

(7) Continuous monitoring system performance evaluation procedures and acceptance criteria (*e.g.*, calibrations).

(8) Procedures for the proper operation and maintenance of monitoring equipment consistent with the requirements in §§ 63.8600 and 63.8(c)(1), (3), (4)(ii), (7), and (8).

(9) Continuous monitoring system data quality assurance procedures consistent with the requirements in § 63.8(d).

(10) Continuous monitoring system recordkeeping and reporting procedures consistent with the requirements in § 63.10(c), (e)(1), and (e)(2)(i).

(11) Procedures for responding to operating parameter deviations, including the procedures in paragraphs (b)(11)(i) through (iii) of this section.

(i) Procedures for determining the cause of the operating parameter deviation.

(ii) Actions for correcting the deviation and returning the operating parameters to the allowable limits.

(iii) Procedures for recording the times that the deviation began and ended, and corrective actions were initiated and completed.

(12) Procedures for keeping records to document compliance.

(13) If you operate an affected kiln and you plan to take the kiln control device out of service for routine maintenance, as specified in § 63.8570(e), the procedures specified in paragraphs (b)(13)(i) and (ii) of this section.

(i) Procedures for minimizing HAP emissions from the kiln during periods of routine maintenance of the kiln control device when the kiln is operating and the control device is offline.

(ii) Procedures for minimizing the duration of any period of routine maintenance on the kiln control device when the kiln is operating and the control device is offline.

(c) Changes to the operating limits in your OM&M plan require a new performance test. If you are revising an operating limit parameter value, you must meet the requirements in paragraphs (c)(1) and (2) of this section.

(1) Submit a notification of performance test to the Administrator as specified in § 63.7(b).

(2) After completing the performance test to demonstrate that compliance with the emission limits can be achieved at the revised operating limit parameter value, you must submit the performance test results and the revised operating limits as part of the Notification of Compliance Status required under § 63.9(h).

(d) If you are revising the inspection and maintenance procedures in your OM&M plan, you do not need to conduct a new performance test.

Testing and Initial Compliance Requirements

§ 63.8585 By what date must I conduct performance tests?

For each kiln that is subject to the emission limits specified in Table 1 to this subpart, you must conduct performance tests within 180 calendar days after the compliance date that is specified for your source in § 63.8545 and according to the provisions in § 63.7(a)(2).

§ 63.8590 When must I conduct subsequent performance tests?

(a) For each kiln that is subject to the emission limits specified in Table 1 to this subpart, you must conduct a performance test before renewing your 40 CFR part 70 operating permit or at least every 5 years following the initial performance test.

(b) You must conduct a performance test when you want to change the parameter value for any operating limit specified in your OM&M plan.

§ 63.8595 How do I conduct performance tests and establish operating limits?

(a) You must conduct each performance test in Table 4 to this subpart that applies to you.

(b) Before conducting the performance test, you must install and calibrate all monitoring equipment.

(c) Each performance test must be conducted according to the requirements in § 63.7 and under the specific conditions in Table 4 to this subpart.

(d) You must test while operating at the maximum production level.

(e) You may not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in § 63.7(e)(1).

(f) You must conduct at least 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) You must use the data gathered during the performance test and the equations in paragraphs (g)(1) and (2) of this section to determine compliance with the emission limitations.

(1) To determine compliance with the production-based hydrogen fluoride (HF), hydrogen chloride (HCl), and particulate matter (PM) emission limits in Table 1 to this subpart, you must calculate your mass emissions per unit of production for each test run using Equation 1 of this section:

$$MP = \frac{ER}{P} \qquad \text{(Eq. 1)}$$

Where:

MP=mass per unit production, kilograms (pounds) of pollutant per megagram (ton) of fired product
ER=mass emission rate of pollutant (HF, HCl, or PM) during each performance test run, kilograms (pounds) per hour
P=production rate during each performance test run, megagrams (tons) of fired product per hour.

(2) To determine compliance with the percent reduction HF and HCl emission limits in Table 1 to this subpart, you must calculate the percent reduction for each test run using Equation 2 of this section:

$$PR = \frac{ER_i - ER_o}{ER_i}(100) \qquad \text{(Eq. 2)}$$

Where:

PR=percent reduction, percent
ER_i=mass emission rate of specific HAP (HF or HCl) entering the APCD, kilograms (pounds) per hour
ER_o=mass emission rate of specific HAP (HF or HCl) exiting the APCD, kilograms (pounds) per hour.

(h) You must establish each site-specific operating limit in Table 2 to this subpart that applies to you as specified in Table 4 to this subpart.

(i) For each kiln that is subject to the emission limits specified in Table 1 to this subpart and is equipped with an APCD that is not addressed in Table 2 to this subpart or that is using process changes as a means of meeting the emission limits in Table 1 to this subpart, you must meet the requirements in § 63.8(f) and paragraphs (i)(1) and (2) of this section.

(1) Submit a request for approval of alternative monitoring procedures to the Administrator no later than the notification of intent to conduct a performance test. The request must contain the information specified in paragraphs (i)(1)(i) through (iv) of this section.

(i) A description of the alternative APCD or process changes.

(ii) The type of monitoring device or procedure that will be used.

(iii) The operating parameters that will be monitored.

(iv) The frequency that the operating parameter values will be determined and recorded to establish continuous compliance with the operating limits.

(2) Establish site-specific operating limits during the performance test based on the information included in the approved alternative monitoring procedures request and, as applicable, as specified in Table 4 to this subpart.

§ 63.8600 What are my monitoring installation, operation, and maintenance requirements?

(a) You must install, operate, and maintain each CMS according to your OM&M plan and the requirements in paragraphs (a)(1) through (5) of this section.

(1) Conduct a performance evaluation of each CMS according to your OM&M plan.

(2) The CMS must complete a minimum of one cycle of operation for each successive 15-minute period. To have a valid hour of data, you must have

at least three of four equally spaced data values (or at least 75 percent if you collect more than four data values per hour) for that hour (not including startup, shutdown, malfunction, out-of-control periods, or periods of routine control device maintenance covered by a routine control device maintenance exemption as specified in § 63.8570(e)).

(3) Determine and record the 3-hour block averages of all recorded readings, calculated after every 3 hours of operation as the average of the previous 3 operating hours. To calculate the average for each 3-hour average period, you must have at least 75 percent of the recorded readings for that period (not including startup, shutdown, malfunction, out-of-control periods, or periods of routine control device maintenance covered by a routine control device maintenance exemption as specified in § 63.8570(e)).

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

(5) At all times, maintain the monitoring equipment including, but not limited to, maintaining necessary parts for routine repairs of the monitoring equipment.

(b) For each liquid flow measurement device, you must meet the requirements in paragraphs (a)(1) through (5) and paragraphs (b)(1) through (3) of this section.

(1) Locate the flow sensor in a position that provides a representative flowrate.

(2) Use a flow sensor with a minimum measurement sensitivity of 2 percent of the liquid flowrate.

(3) At least semiannually, conduct a flow sensor calibration check.

(c) For each pressure measurement device, you must meet the requirements in paragraphs (a)(1) through (5) and paragraphs (c)(1) through (7) of this section.

(1) Locate the pressure sensor(s) in or as close to 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 measurement sensitivity of 0.5 inch of water or a transducer with a minimum measurement sensitivity of 1 percent of the pressure range.

(4) Check the pressure tap daily to ensure that it is not plugged.

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

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

(7) At least monthly, inspect all components for integrity, all electrical connections for continuity, and all mechanical connections for leakage.

(d) For each pH measurement device, you must meet the requirements in paragraphs (a)(1) through (5) and paragraphs (d)(1) through (4) of this section.

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

(4) At least monthly, inspect all components for integrity and all electrical connections for continuity.

(e) For each bag leak detection system, you must meet the requirements in paragraphs (e)(1) through (11) of this section.

(1) Each triboelectric bag leak detection system must be installed, calibrated, operated, and maintained according to the ''Fabric Filter Bag Leak Detection Guidance,'' (EPA–454/R–98–015, September 1997). This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality Planning and Standards; Emissions, Monitoring and Analysis Division; Emission Measurement Center (MD–19), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center, Continuous Emission Monitoring. Other types of bag leak detection systems must be installed, operated, calibrated, and maintained in a manner consistent with the manufacturer's written specifications and recommendations.

(2) The bag leak detection system must be certified by the manufacturer to be capable of detecting PM emissions at concentrations of 10 milligrams per actual cubic meter (0.0044 grains per actual cubic foot) or less.

(3) The bag leak detection system sensor must provide an output of relative PM loadings.

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

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

(6) For positive pressure fabric filter systems, a bag leak detector must be installed in each baghouse compartment or cell.

(7) For negative pressure or induced air fabric filters, the bag leak detector must be installed downstream of the fabric filter.

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

(9) The baseline output must be established by adjusting the range and the averaging period of the device and establishing the alarm set points and the alarm delay time according to section 5.0 of the ''Fabric Filter Bag Leak Detection Guidance.''

(10) Following initial adjustment of the system, the sensitivity or range, averaging period, alarm set points, or alarm delay time may not be adjusted except as detailed in your OM&M plan. In no case may the sensitivity be increased by more than 100 percent or decreased more than 50 percent over a 365-day period unless such adjustment follows a complete fabric filter inspection which demonstrates that the fabric filter is in good operating condition. Record each adjustment.

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

(f) For each lime or chemical feed rate measurement device, you must meet the requirements in paragraphs (a)(1) through (5) and paragraphs (f)(1) and (2) of this section.

(1) Locate the measurement device in a position that provides a representative feed rate measurement.

(2) At least semiannually, conduct a calibration check.

(g) For each limestone feed system on a DLA, you must meet the requirements in paragraphs (a)(1), (4), and (5) of this section and must ensure on a monthly basis that the feed system replaces limestone at least as frequently as the schedule set during the performance test.

(h) Requests for approval of alternate monitoring procedures must meet the requirements in §§ 63.8595(i) and 63.8(f).

§ 63.8605 How do I demonstrate initial compliance with the emission limitations and work practice standards?

(a) You must demonstrate initial compliance with each emission limitation and work practice standard that applies to you according to Table 5 to this subpart.

(b) You must establish each site-specific operating limit in Table 2 to this subpart that applies to you according to the requirements in § 63.8595 and Table 4 to this subpart.

(c) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in § 63.8630(e).

Continuous Compliance Requirements

§ 63.8615 How do I monitor and collect data to demonstrate continuous compliance?

(a) You must monitor and collect data according to this section.

(b) Except for periods of 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. This includes periods of startup, shutdown, malfunction, and routine control device maintenance as specified in § 63.8570(e) when the affected source is operating.

(c) You may not use data recorded during monitoring malfunctions, associated repairs, out-of-control periods, or required quality assurance or control activities for purposes of calculating data averages. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions. You must use all the valid data collected during all other periods in assessing compliance. Any averaging period for which you do not have valid monitoring data and such data are required constitutes a deviation from the monitoring requirements.

§ 63.8620 How do I demonstrate continuous compliance with the emission limitations and work practice standards?

(a) You must demonstrate continuous compliance with each emission limit, operating limit, and work practice standard in Tables 1, 2, and 3 to this subpart that applies to you according to the methods specified in Table 6 to this subpart.

(b) For each kiln that is subject to the emission limits specified in Table 1 to this subpart and is equipped with an APCD that is not addressed in Table 2 to this subpart, or that is using process changes as a means of meeting the emission limits in Table 1 to this subpart, you must demonstrate continuous compliance with each emission limit in Table 1 to this subpart, and each operating limit established as required in § 63.8595(i)(2) according to the methods specified in your approved alternative monitoring procedures request, as described in §§ 63.8595(i)(1) and 63.8(f).

(c) You must report each instance in which you did not meet each emission limit and operating limit in this subpart that applies to you. This includes periods of startup, shutdown, malfunction, and routine control device maintenance. These instances are deviations from the emission limitations in this subpart. These deviations must be reported according to the requirements in § 63.8635.

(d) During periods of startup, shutdown, and malfunction, you must operate according to your SSMP.

(e) 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 Administrator's satisfaction that you were operating according to an SSMP that satisfies the requirements of § 63.6(e) and your OM&M plan. The 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).

(f) Deviations that occur during periods of control device maintenance covered by an approved routine control device maintenance exemption according to § 63.8570(e) are not violations if you demonstrate to the Administrator's satisfaction that you were operating in accordance with the approved routine control device maintenance exemption.

(g) You must demonstrate continuous compliance with the operating limits in Table 2 to this subpart for visible emissions (VE) from tunnel kilns equipped with DLA, DIFF, or DLS/FF by monitoring VE at each kiln stack according to the requirements in paragraphs (g)(1) through (3) of this section.

(1) Perform daily VE observations of each kiln stack according to the procedures of Method 22 of 40 CFR part 60, appendix A. You must conduct the Method 22 test while the affected source is operating under normal conditions. The duration of each Method 22 test must be at least 15 minutes.

(2) If VE are observed during any daily test conducted using Method 22 of 40 CFR part 60, appendix A, you must promptly initiate and complete corrective actions according to your OM&M plan. If no VE are observed in 30 consecutive daily Method 22 tests for any kiln stack, you may decrease the frequency of Method 22 testing from daily to weekly for that kiln stack. If VE are observed during any weekly test, you must promptly initiate and complete corrective actions according to your OM&M plan, resume Method 22 testing of that kiln stack on a daily basis, and maintain that schedule until no VE are observed in 30 consecutive daily tests, at which time you may again decrease the frequency of Method 22 testing to a weekly basis.

(3) If VE are observed during any test conducted using Method 22 of 40 CFR part 60, appendix A, you must report these deviations by following the requirements in § 63.8635.

Notifications, Reports, and Records

§ 63.8630 What notifications must I submit and when?

(a) You must submit all of the notifications in §§ 63.7(b) and (c), 63.8(f)(4), and 63.9 (b) through (e), (g)(1), and (h) that apply to you, by the dates specified.

(b) As specified in § 63.9(b)(2) and (3), if you start up your affected source before May 16, 2003, you must submit an Initial Notification not later than 120 calendar days after May 16, 2003.

(c) As specified in § 63.9(b)(3), if you start up your new or reconstructed affected source or affected source described in § 63.8540(f)(1) or § 63.8540(f)(2) on or after May 16, 2003, you must submit an Initial Notification not later than 120 calendar days after you become subject to this subpart.

(d) If you are required to conduct a performance test, you must submit a written notification of intent to conduct a performance test at least 60 calendar days before the performance test is scheduled to begin, as required in § 63.7(b)(1).

(e) If you are required to conduct a performance test or other initial compliance demonstration as specified in Tables 4 and 5 to this subpart, you must submit a Notification of Compliance Status as specified in § 63.9(h) and paragraphs (e)(1) through (3) of this section.

(1) For each compliance demonstration that includes a performance test conducted according to the requirements in Table 4 to this subpart, you must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th calendar day following the completion of the performance test, according to § 63.10(d)(2).

(2) In addition to the requirements in § 63.9(h)(2)(i), you must include the information in paragraphs (e)(2)(i) and (ii) of this section in your Notification of Compliance Status:

(i) The operating limit parameter values established for each affected source with supporting documentation and a description of the procedure used to establish the values.

(ii) For each APCD that includes a fabric filter, if a bag leak detection system is used, analysis and supporting documentation demonstrating conformance with EPA guidance and specifications for bag leak detection systems in § 63.8600(e).

(3) For each compliance demonstration required in Table 5 to this subpart that does not include a performance test (*i.e.*, compliance demonstration for the work practice standard), you must submit the Notification of Compliance Status before the close of business on the 30th calendar day following the completion of the compliance demonstration.

(f) If you request a routine control device maintenance exemption according to § 63.8570(e), you must submit your request for the exemption no later than 30 days before the compliance date.

(g) If you own or operate an affected kiln that is subject to the work practice standards specified in Table 3 to this subpart, and you intend to use a fuel other than natural gas or equivalent to fire the affected kiln, 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 § 63.8665. 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 kiln.

(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.

§ 63.8635 What reports must I submit and when?

(a) You must submit each report in Table 7 to this subpart that applies to you.

(b) Unless the Administrator has approved a different schedule for submission of reports under § 63.10(a), you must submit each report by the date in Table 7 to this subpart and as specified 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 § 63.8545 and ending on June 30 or December 31, and lasting at least 6 months, but less than 12 months. For example, if your compliance date is March 1, then the first semiannual reporting period would begin on March 1 and end on December 31.

(2) The first compliance report must be postmarked or delivered no later than July 31 or January 31 for compliance periods ending on June 30 and December 31, respectively.

(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 for compliance periods ending on June 30 and December 31, respectively.

(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 in paragraphs (c)(1) through (7) of this section.

(1) Company name and address.

(2) Statement by a responsible official with that official's name, title, and signature, certifying that, based on information and belief formed after reasonable inquiry, the statements and information in the report are true, accurate, and complete.

(3) Date of report and beginning and ending dates of the reporting period.

(4) If you had a startup, shutdown or malfunction during the reporting period and you took actions consistent with your SSMP and OM&M plan, the compliance report must include the information specified in § 63.10(d)(5)(i).

(5) A description of control device maintenance performed while the control device was offline and the kiln controlled by the control device was operating, including the information specified in paragraphs (c)(5)(i) through (iii) of this section.

(i) The date and time when the control device was shutdown and restarted.

(ii) Identification of the kiln that was operating and the number of hours that the kiln operated while the control device was offline.

(iii) A statement of whether or not the control device maintenance was included in your approved routine control device maintenance exemption developed as specified in § 63.8570(e). If the control device maintenance was included in your approved routine control device maintenance exemption, then you must report the information in paragraphs (c)(5)(iii)(A) through (C) of this section.

(A) The total amount of time that the kiln controlled by the control device operated during the current semiannual compliance period and during the previous semiannual compliance period.

(B) The amount of time that each kiln controlled by the control device operated while the control device was offline for maintenance covered under the routine control device maintenance exemption during the current semiannual compliance period and during the previous semiannual compliance period.

(C) Based on the information recorded under paragraphs (c)(5)(iii)(A) and (B) of this section, compute the annual percent of kiln operating uptime during which the control device was offline for routine maintenance using Equation 1 of this section.

$$RM = \frac{DT_p + DT_c}{KU_p + KU_c}\,(100) \qquad \text{(Eq. 1)}$$

Where:

RM=Annual percentage of kiln uptime during which control device is down for routine control device maintenance

DT_p=Control device downtime claimed under the routine control device maintenance exemption for the previous semiannual compliance period

DT_c=Control device downtime claimed under the routine control device maintenance exemption for the current semiannual compliance period

KU_p=Kiln uptime for the previous semiannual compliance period

KU_c=Kiln uptime for the current semiannual compliance period

(6) If there are no deviations from any emission limitations (emission limits or operating limits) or work practice standards that apply to you, the compliance report must contain a statement that there were no deviations from the emission limitations or work practice standards during the reporting period.

(7) If there were no periods during which the CMS was out-of-control as specified in your OM&M plan, the

compliance report must contain a statement that there were no periods during which the CMS was out-of-control during the reporting period.

(d) For each deviation from an emission limitation (emission limit or operating limit) that occurs at an affected source where you are not using a CMS to comply with the emission limitations in this subpart, the compliance report must contain the information in paragraphs (c)(1) through (5) and paragraphs (d)(1) and (2) of this section. This includes periods of startup, shutdown, malfunction, and routine control device maintenance.

(1) The total operating time of each affected source during the reporting period.

(2) Information on the number, duration, and cause of deviations (including unknown cause, if applicable), as applicable, and the corrective action taken.

(e) For each deviation from an emission limitation (emission limit or operating limit) occurring at an affected source where you are using a CMS to comply with the emission limitations in this subpart, you must include the information in paragraphs (c)(1) through (5) and paragraphs (e)(1) through (13) of this section. This includes periods of startup, shutdown, malfunction, and routine control device maintenance.

(1) The total operating time of each affected source during the reporting period.

(2) The date and time that each malfunction started and stopped.

(3) The date and time that each CMS was inoperative, except for zero (low-level) and high-level checks.

(4) The date, time, and duration that each CMS was out-of-control, including the pertinent information in your OM&M plan.

(5) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of startup, shutdown, or malfunction; during routine control device maintenance covered in your approved routine control device maintenance exemption; or during another period.

(6) A description of corrective action taken in response to a deviation.

(7) 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.

(8) 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.

(9) A summary of the total duration of CMS 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.

(10) A brief description of the process units.

(11) A brief description of the CMS.

(12) The date of the latest CMS certification or audit.

(13) A description of any changes in CMS, processes, or control equipment since the last reporting period.

(f) If you have obtained a title V operating permit according to 40 CFR part 70 or 40 CFR part 71, you 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 you submit a compliance report according to Table 7 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 limitation (including any operating limit), then submitting the compliance report will satisfy any obligation to report the same deviations in the semiannual monitoring report. However, submitting a compliance report will not otherwise affect any obligation you may have to report deviations from permit requirements to the permitting authority.

(g) If you own or operate an affected kiln that is subject to the work practice standard specified in Table 3 to this subpart, and you use a fuel other than natural gas or equivalent to fire the affected kiln, you must submit a report of alternative fuel use within 10 working days after terminating the use of the alternative fuel. The report must include the information in paragraphs (g)(1) through (6) of this section.

(1) Company name and address.

(2) Identification of the affected kiln.

(3) Reason for using the alternative fuel.

(4) Type of alternative fuel used to fire the affected kiln.

(5) Dates that the use of the alternative fuel started and ended.

(6) Amount of alternative fuel used.

§ 63.8640 What records must I keep?

(a) You must keep the records listed in paragraphs (a)(1) through (4) 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 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 as required in § 63.10(b)(2)(viii).

(4) Records relating to control device maintenance and documentation of your approved routine control device maintenance exemption, if you request such an exemption under § 63.8570(e).

(b) You must keep the records required in Table 6 to this subpart to show continuous compliance with each emission limitation that applies to you.

(c) You must also maintain the records listed in paragraphs (c)(1) through (7) of this section.

(1) For each bag leak detection system, records of each alarm, the time of the alarm, the time corrective action was initiated and completed, and a brief description of the cause of the alarm and the corrective action taken.

(2) For each deviation of an operating limit parameter value, the date, time, and duration of the deviation, a brief explanation of the cause of the deviation and the corrective action taken, and whether the deviation occurred during a period of startup, shutdown, or malfunction.

(3) For each kiln that is subject to the emission limits in Table 1, records of production rates on a fired-product weight basis.

(4) For each kiln that is subject to the emission limits in Table 1, records for any approved alternative monitoring or test procedures.

(5) For each kiln that is subject to the emission limits in Table 1, records of maintenance and inspections performed on the APCD.

(6) For each kiln that is subject to the emission limits in Table 1, current copies of your SSMP and OM&M plan, including any revisions, with records documenting conformance.

(7) Records that document compliance with any work practice standard that applies to you.

§ 63.8645 In what form and for 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 onsite 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 may keep the records offsite for the remaining 3 years.

Other Requirements and Information

§ 63.8655 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§ 63.1 through 63.15 apply to you.

§ 63.8660 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by us, the U.S. EPA, or a delegated authority such as your State, local, or tribal agency. If the U.S. EPA Administrator has delegated authority to your State, local, or tribal agency, then that agency, in addition to the U.S. EPA, has the authority to implement and enforce this subpart. You should contact your U.S. EPA Regional Office to find out if implementation and enforcement of 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 section 40 CFR part 63, subpart E, the authorities contained in paragraph (c) of this section are retained by the Administrator of the U.S. EPA and are not transferred to the State, local, or tribal agency.

(c) The authorities that cannot be delegated to State, local, or tribal agencies are as specified in paragraphs (c)(1) through (4) of this section.

(1) Approval of alternatives to the applicability requirements in §§ 63.8535 and 63.8540, the compliance date requirements in § 63.8545, and the non-opacity emission limitations in § 63.8555.

(2) Approval of major changes to test methods under § 63.7(e)(2)(ii) and (f) and as defined in § 63.90.

(3) Approval of major changes to monitoring under § 63.8(f) and as defined in § 63.90.

(4) Approval of major changes to recordkeeping and reporting under § 63.10(f) and as defined in § 63.90.

§ 63.8665 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act, in § 63.2, and in this section as follows:

Air pollution control device (APCD) means any equipment that reduces the quantity of a pollutant that is emitted to the air.

Bag leak detection system means an instrument that is capable of monitoring PM loadings in the exhaust of a fabric filter in order to detect bag failures. A bag leak detection system includes, but is not limited to, an instrument that operates on triboelectric, light-scattering, light-transmittance, or other effects to monitor relative PM loadings.

Clay ceramics manufacturing facility means a plant site that manufactures pressed floor tile, pressed wall tile, other pressed tile, or sanitaryware (*e.g.,* sinks and toilets). Clay ceramics manufacturing facilities typically process clay, shale, and various additives, form the processed materials into tile or sanitaryware shapes, and dry and fire the ceramic products. Glazes are applied to many tile and sanitaryware products.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limitation (including any operating limit) or work practice standard;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limitation (including any operating limit) or work practice standard in this subpart during startup, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

Dry lime injection fabric filter (DIFF) means an APCD that includes continuous injection of hydrated lime or other sorbent into a duct or reaction chamber followed by a fabric filter.

Dry lime scrubber/fabric filter (DLS/FF) means an APCD that includes continuous injection of humidified hydrated lime or other sorbent into a reaction chamber followed by a fabric filter. These systems typically include recirculation of some of the sorbent.

Dry limestone adsorber (DLA) means an APCD that includes a limestone storage bin, a reaction chamber that is essentially a packed tower filled with limestone, and may or may not include a peeling drum that mechanically scrapes reacted limestone to regenerate the stone for reuse.

Emission limitation means any emission limit or operating limit.

Fabric filter means an APCD used to capture PM by filtering a gas stream through filter media; also known as a baghouse.

Initial startup means:

(1) For a new or reconstructed tunnel kiln controlled with a DLA, and for a tunnel kiln that would be considered reconstructed but for § 63.8540(f)(1) or § 63.8540(f)(2), the time at which the temperature in the kiln first reaches 260 °C (500 °F) and the kiln contains product; or

(2) For a new or reconstructed tunnel kiln controlled with a DIFF, DLS/FF, or WS, the time at which the kiln first reaches a level of production that is equal to 75 percent of the kiln design capacity or 12 months after the affected source begins firing clay ceramics, whichever is earlier.

Particulate matter (PM) means, for purposes of this subpart, emissions of PM that serve as a measure of total particulate emissions, as measured by Method 5 (40 CFR part 60, appendix A), and as a surrogate for metal HAP contained in the particulates including, but not limited to, antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, mercury, nickel, and selenium.

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.

Plant site means all contiguous or adjoining property that is under common control, including properties that are separated only by a road or other public right-of-way. Common control includes properties that are owned, leased, or operated by the same entity, parent entity, subsidiary, or any combination thereof.

Research and development kiln means any kiln whose purpose is to conduct research and development for new processes and products and is not engaged in the manufacture of products for commercial sale, except in a *de minimis* manner.

Responsible official means responsible official as defined in 40 CFR 70.2.

Startup means the setting in operation of an affected source and starting the production process.

Tunnel kiln means any continuous kiln that is not a roller kiln that is used to fire clay ceramics.

Tunnel kiln design capacity means the maximum amount of clay ceramics, in Mg (tons), that a kiln is designed to produce in one year divided by the number of hours in a year (8,760 hours). If a kiln is modified to increase the capacity, the design capacity is considered to be the capacity following modifications.

Wet scrubber (WS) means an APCD that uses water, which may include caustic additives or other chemicals, as the sorbent. Wet scrubbers may use any of various design mechanisms to increase the contact between exhaust gases and the sorbent.

Work practice standard means any design, equipment, work practice, operational standard, or combination thereof, that is promulgated pursuant to section 112(h) of the Clean Air Act.

Tables to Subpart KKKKK of Part 63

As stated in § 63.8555, you must meet each emission limit in the following table that applies to you:

TABLE 1 TO SUBPART KKKKK OF PART 63.—EMISSION LIMITS

For each . . .	You must meet the following emission limits . . .	Or you must comply with the following . . .
1. New or reconstructed tunnel kiln with a design capacity less than 9.07 Mg/hr (10 tph) of fired product; each tunnel kiln that would be considered reconstructed but for § 63.8540(f)(1); and each tunnel kiln that would be considered reconstructed but for § 63.8540(f)(2).	a. HF emissions must not exceed 0.029 kilograms per megagram (kg/Mg) (0.057 pounds per ton (lb/ton)) of fired product.	Reduce uncontrolled HF emissions by at least 90 percent.
	b. HCl emissions must not exceed 0.13 kg/Mg (0.26 lb/ton) of fired product.	Reduce uncontrolled HCl emissions by at least 30 percent.
	c. PM emissions must not exceed 0.21 kg/Mg (0.42 lb/ton) of fired product.	Not applicable.
2. New or reconstructed tunnel kiln with a design capacity equal to or greater than 10 tph of fired product.	a. HF emissions must not exceed 0.029 kg/Mg (0.057 lb/ton) of fired product.	Reduce uncontrolled HF emissions by at least 90 percent.
	b. HCl emissions must not exceed 0.028 kg/Mg (0.056 lb/ton) of fired product.	Reduce uncontrolled HCl emissions by at least 85 percent.
	c. PM emissions must not exceed 0.060 kg/Mg (0.12 lb/ton) of fired product.	Not applicable.

As stated in § 63.8555, you must meet each operating limit in the following table that applies to you:

TABLE 2 TO SUBPART KKKKK OF PART 63.—OPERATING LIMITS

For each . . .	You must . . .
1. Kiln equipped with a DLA	a. Maintain the average pressure drop across the DLA for each 3-hour block period at or above the average pressure drop established during the performance test; and
	b. Maintain a sufficient amount of limestone in the limestone hopper, storage bin (located at the top of the DLA), and DLA at all times; maintain the limestone feeder setting at or above the level established during the performance test; and
	c. Use the same grade of limestone from the same source as was used during the performance test; maintain records of the source and grade of limestone; and
	d. Maintain no VE from the DLA stack.
2. Kiln equipped with a DIFF or DLS/FF.	a. If you use a bag leak detection system, initiate corrective action within 1 hour of a bag leak detection system alarm and complete corrective actions in accordance with your OM&M plan; 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 block reporting period; or maintain no VE from the DIFF or DLS/FF stack; and
	b. Maintain free-flowing lime in the feed hopper or silo and to the APCD at all times for continuous injection systems; maintain the feeder setting at or above the level established during the performance test for continuous injection systems.
3. Kiln equipped with a WS	a. Maintain the average scrubber pressure drop for each 3-hour block period at or above the average pressure drop established during the performance test; and
	b. Maintain the average scrubber liquid pH for each 3-hour block period at or above the average scrubber liquid pH established during the performance test; and
	c. Maintain the average scrubber liquid flow rate for each 3-hour block period at or above the average scrubber liquid flow rate established during the performance test; and
	d. If chemicals are added to the scrubber water, maintain the average scrubber chemical feed rate for each 3-hour block period at or above the average scrubber chemical feed rate established during the performance test.

As stated in § 63.8555, you must comply with each work practice standard in the following table that applies to you:

TABLE 3 TO SUBPART KKKKK OF PART 63.—WORK PRACTICE STANDARDS

For . . .	You must . . .	According to one of the following requirements . . .
Each existing, new, or reconstructed periodic kiln, tunnel kiln, or roller kiln; each tunnel kiln that would be considered reconstructed but for § 63.8540(f)(1); and each tunnel kiln that would be considered reconstructed but for § 63.8540(f)(2).	Minimize fuel-based HAP emissions.	Use natural gas, or equivalent, as the kiln fuel, except during periods of natural gas curtailment or supply interruption, as defined in § 63.8665.

As stated in § 63.8595, you must conduct each performance test in the following table that applies to you:

TABLE 4 TO SUBPART KKKKK OF PART 63.—REQUIREMENTS FOR PERFORMANCE TESTS

For each . . .	You must . . .	Using . . .	According to the following requirements . . .
1. New or reconstructed tunnel kiln; each tunnel kiln that would be considered reconstructed but for § 63.8540(f)(1); and each tunnel kiln that would be considered reconstructed but for § 63.8540(f)(2).	a. Select locations of sampling ports and the number of traverse points.	Method 1 or 1A of 40 CFR part 60, appendix A.	Sampling sites must be located at the outlet of the APCD and prior to any releases to the atmosphere for all affected sources. If you choose to meet the percent emission reduction requirements for HF or HCl, a sampling site must also be located at the APCD inlet.
	b. Determine velocities and volumetric flow rate.	Method 2 of 40 CFR part 60, appendix A.	You may use Method 2A, 2C, 2D, 2F, or 2G of 40 CFR part 60, appendix A, as appropriate, as an alternative to using Method 2 of 40 CFR part 60, appendix A.
	c. Conduct gas molecular weight analysis.	Method 3 of 40 CFR part 60, appendix A.	You may use Method 3A or 3B of 40 CFR part 60, appendix A, as appropriate, as an alternative to using Method 3 of 40 CFR part 60, appendix A.
	d. Measure moisture content of the stack gas.	Method 4 of 40 CFR part 60, appendix A.	
	e. Measure HF and HCl emissions.	Method 26A of 40 CFR part 60, appendix A; or	Conduct the test while operating at the maximum production level. You may use Method 26 of 40 CFR part 60, appendix A, as an alternative to using Method 26A of 40 CFR part 60, appendix A, when no acid PM (*e.g.*, HF or HCl dissolved in water droplets emitted by sources controlled by a WS) is present.
		Method 320 of 40 CFR part 63, appendix A.	Conduct the test while operating at the maximum production level. When using Method 320 of 40 CFR part 63, appendix A, you must follow the analyte spiking procedures of section 13 of Method 320 of 40 CFR part 63, appendix A, unless you can demonstrate that the complete spiking procedure has been conducted at a similar source.
	f. Measure PM emissions	Method 5 of 40 CFR part 60, appendix A.	Conduct the test while operating at the maximum production level.
2. Kiln that is complying with production-based emission limits.	Determine the production rate during each test run in order to determine compliance with production-based emission limits.	Production data collected during the performance tests (*e.g.,* the number of ceramic pieces and weight per piece in the kiln during a test run divided by the amount of time to fire a piece).	You must measure and record the production rate, on a fired-product weight basis, of the affected kiln for each of the three test runs.
3. Kiln equipped with a DLA.	a. Establish the operating limit for the average pressure drop across the DLA.	Data from the pressure drop measurement device during the performance test.	You must continuously measure the pressure drop across the DLA, determine and record the block average pressure drop values for the three test runs, and determine and record the 3-hour block average of the recorded pressure drop measurements for the three test runs.

TABLE 4 TO SUBPART KKKKK OF PART 63.—REQUIREMENTS FOR PERFORMANCE TESTS—Continued

For each . . .	You must . . .	Using . . .	According to the following requirements . . .
	b. Establish the operating limit for the limestone feeder setting.	Data from the limestone feeder during the performance test.	You must ensure that you maintain an adequate amount of limestone in the limestone hopper, storage bin (located at the top of the DLA), and DLA at all times during the performance test. You must establish your limestone feeder setting one week prior to the performance test and maintain the feeder setting for the one-week period that precedes the performance test and during the performance test.
	c. Document the source and grade of limestone used.	Records of limestone purchase.	
4. Kiln equipped with a DIFF or DLS/FF	Establish the operating limit for the lime feeder setting.	Data from the lime feeder during the performance test.	For continuous lime injection systems, you must ensure that lime in the feed hopper or silo and to the APCD is free-flowing at all times during the performance test and record the feeder setting for the three test runs. If the feed rate setting varies during the three test runs, determine and record the average feed rate from the three test runs.
5. Kiln equipped with a WS	a. Establish the operating limit for the average scrubber pressure drop.	Data from the pressure drop measurement device during the performance test.	You must continuously measure the scrubber pressure drop, determine and record the block average pressure drop values for the three test runs, and determine and record the 3-hour block average of the recorded pressure drop measurements for the three test runs.
	b. Establish the operating limit for the average scrubber liquid pH.	Data from the pH measurement device during the performance test.	You must continuously measure the scrubber liquid pH, determine and record the block average pH values for the three test runs, and determine and record the 3-hour block average of the recorded pH measurements for the three test runs.
	c. Establish the operating limit for the average scrubber liquid flow rate.	Data from the flow rate measurement device during the performance test.	You must continuously measure the scrubber liquid flow rate, determine and record the block average flow rate values for the three test runs, and determine and record the 3-hour block average of the recorded flow rate measurements for the three test runs.
6. Kiln equipped with a WS that includes chemical addition to the water.	Establish the operating limit for the average scrubber chemical feed rate.	Data from the chemical feed rate measurement device during the performance test.	You must continuously measure the scrubber chemical feed rate, determine and record the block average chemical feed rate values for the three test runs, and determine and record the 3-hour block average of the recorded chemical feed rate measurements for the three test runs.

As stated in § 63.8605, you must demonstrate initial compliance with each emission limitation that applies to you according to the following table:

TABLE 5 TO SUBPART KKKKK OF PART 63.—INITIAL COMPLIANCE WITH EMISSION LIMITATIONS AND WORK PRACTICE STANDARDS

For each . . .	For the following . . .	You have demonstrated initial compliance if . . .
1. New or reconstructed tunnel kiln with a design capacity less than 9.07 Mg/hr (10 tph) of fired product; each tunnel kiln that would be considered reconstructed but for § 63.8540(f)(1); and each tunnel kiln that would be considered reconstructed but for § 63.8540(f)(2).	a. HF emissions must not exceed 0.029 kg/Mg (0.057 lb/ton) of fired product; or uncontrolled HF emissions must be reduced by at least 90 percent; and.	i. The HF emissions measured using Method 26A of 40 CFR part 60, appendix A or Method 320 of 40 CFR part 63, appendix A over the period of the initial performance test, according to the calculations in § 63.8595(g)(1), do not exceed 0.029 kg/Mg (0.057 lb/ton); or uncontrolled HF emissions measured using Method 26A of 40 CFR part 60, appendix A or Method 320 of 40 CFR part 63, appendix A over the period of the initial performance test are reduced by at least 90 percent, according to the calculations in § 63.8595(g)(2); and ii. You establish and have a record of the operating limits listed in Table 2 to this subpart over the 3-hour performance test during which HF emissions did not exceed 0.029 kg/Mg (0.057 lb/ton) or uncontrolled HF emissions were reduced by at least 90 percent.
	b. HCl emissions must not exceed 0.13 kg/Mg (0.26 lb/ton) of fired product; or uncontrolled HCl emissions must be reduced by at least 30 percent; and	i. The HCl emissions measured using Method 26A of 40 CFR part 60, appendix A or Method 320 of 40 CFR part 63, appendix A over the period of the initial performance test, according to the calculations in § 63.8595(g)(1), do not exceed 0.13 kg/Mg (0.26 lb/ton); or uncontrolled HCl emissions measured using Method 26A of 40 CFR part 60, appendix A or Method 320 of 40 CFR part 63, appendix A over the period of the initial performance test are reduced by at least 30 percent, according to the calculations in § 63.8595(g)(2); and ii. You establish and have a record of the operating limits listed in Table 2 to this subpart over the 3-hour performance test during which HCl emissions did not exceed 0.13 kg/Mg (0.26 lb/ton) or uncontrolled HCl emissions were reduced by at least 30 percent.
	c. PM emissions must not exceed 0.21 kg/Mg (0.42 lb/ton) of fired product.	i. The PM emissions measured using Method 5 of 40 CFR part 60, appendix A, over the period of the initial performance test, according to the calculations in § 63.8595(g)(1), do not exceed 0.21 kg/Mg (0.42 lb/ton); and ii. You establish and have a record of the operating limits listed in Table 2 to this supbart over the 3-hour performance test during which PM emissions did not exceed 0.21 kg/Mg (0.42 lb/ton).
2. New or reconstructed tunnel kiln with a design capacity equal to or greater than 10 tph of fired product.	a. HF emissions must not exceed 0.029 kg/Mg (0.057 lb/ton) of fired product; or uncontrolled HF emissions must be reduced by at least 90 percent; and	i. The HF emissions measured using Method 26A of 40 CFR part 60, appendix A or Method 320 of 40 CFR part 63, appendix A over the period of the initial performance test, according to the calculations in § 63.8595(g)(1), do not exceed 0.029 kg/Mg (0.057 lb/ton); or uncontrolled HF emissions measured using Method 26A of 40 CFR part 60, appendix A or Method 320 of 40 CFR part 63, appendix A over the period of the initial performance test are reduced by at least 90 percent, according to the calculations in § 63.8595(g)(2); and ii. You establish and have a record of the operating limits listed in Table 2 to this subpart over the 3-hour performance test during which HF emissions did not exceed 0.029 kg/Mg (0.057 lb/ton) or uncontrolled HF emissions were reduced by at least 90 percent.
	b. HCl emissions must not exceed 0.028 kg/Mg (0.056 lb.ton) of fired product; or uncontrolled HCl emissions must be reduced by at least 85 percent; and	i. The HCl emissions measured using Method 26A of 40 CFR part 60, appendix A or Method 320 of 40 CFR part 63, appendix A over the period of the initial performance test, according to the calculations in § 63.8595(g)(1), do not exceed 0.028 kg/Mg (0.056 lb/ton); or uncontrolled HCl emissions measured using Method 26A of 40 CFR part 60, appendix A or Method 320 of 40 CFR part 63, appendix A over the period of the initial performance test are reduced by at least 85 percent, according to the calculations in § 63.8595(g)(2); and ii. You establish and have a record of the operating limits listed in Table 2 to this subpart over the 3-hour performance test during which HCl emissions did not exceed 0.028 kg/Mg (0.056 lb/ton) or uncontrolled HCl emissions were reduced by at least 85 percent.
	c. PM emissions must not exceed 0.060 kg/Mg (0.12 lb/ton) of fired product.	i. The PM emissions measured using Method 5 of 40 CFR part 60, appendix A, over the period of the initial performance test, according to the calculations on § 63.8595(g)(1), do not exceed 0.060 kg/Mg (0.12 lb/ton); and ii. You establish and have a record of the operating limits listed in Table 2 to this subpart over the 3-hour performance test during which PM emissions did not exceed 0.060 kg/Mg (0.12 lb/ton).

TABLE 5 TO SUBPART KKKKK OF PART 63.—INITIAL COMPLIANCE WITH EMISSION LIMITATIONS AND WORK PRACTICE STANDARDS—Continued

For each . . .	For the following . . .	You have demonstrated initial compliance if . . .
3. Existing, new, or reconstructed periodic kiln, tunel kiln, or roller kiln; each tunnel kiln that would be considered reconstructed but for § 63.8540(f)(1); and each tunnel kiln that would be considered reconstructed but for § 63.8540(f)(2).	Minimize fuel-based HAP emissions.	You use natural gas, or equivalent, as the kiln fuel.

As stated in § 63.8620, you must demonstrate continuous compliance with each emission limit and operating limit that applies to you according to the following table:

TABLE 6 TO SUBPART KKKKK OF PART 63.—CONTINUOUS COMPLIANCE WITH EMISSION LIMITATIONS AND WORK PRACTICE STANDARDS

For each . . .	For the following . . .	You must demonstrate continuous compliance by . . .
1. Kiln equipped with a DLA	a. Each emission limit in Table 1 to this subpart and each operating limit in Item 1 of Table 2 to this subpart for kilns equipped with a DLA.	i. Collecting the DLA pressure drop data according to § 63.8600(a); reducing the DLA pressure drop data to 3-hour block averages according to § 63.8600(a); maintaining the average pressure drop across the DLA for each 3-hour block period at or above the average pressure drop established during the performance test; and ii. Verifying that the limestone hopper and storage bin (located at the top of the DLA) contain adequate limestone by performing a daily visual check; and iii. Recording the limestone feeder setting daily to verify that the feeder setting is being maintained at or above the level established during the performance test; and iv. Using the same grade of limestone from the same source as was used during the performance test; maintaining records of the source and type of limestone; and v. Performing VE observations of the DLA stack at the frequency specified in § 63.8620(g) using Method 22 of 40 CFR part 60, appendix A; maintaining no VE from the DLA stack.
2. Kiln equipped with a DIFF or DLS/FF.	a. Each emission limit in Table 1 to this subpart and each operating limit in Item 2 of Table 2 to this subpart for kilns equipped with DIFF or DLS/FF.	i. If you use a bag leak detection system, initiating corrective action within 1 hour of a bag leak detection system alarm and completing corrective actions in accordance with your OM&M plan; operating and maintaining the fabric filter such that the alarm is not engaged for more than 5 percent of the total operating time in a 6-month block reporting period; in calculating this operating time fraction, 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 is counted as a minimum of 1 hour; if you take longer than 1 hour to initiate corrective action, the alarm time is counted as the actual amount of time taken by you to initiate corrective action; or performing VE observations of the DIFF or DLS/FF stack at the frequency specified in § 63.8620(g) using Method 22 of 40 CFR part 60, appendix A; maintaining no VE from the DIFF or DLS/FF stack; and ii. Verifying that lime is free-flowing via a load cell, carrier gas/lime flow indicator, carrier gas pressure drop measurement system, or other system; recording all monitor or sensor output, and if lime is found not to be free flowing, promptly initiating and completing corrective actions in accordance with your OM&M plan; recording the feeder setting once each shift of operation to verify that the feeder setting is being maintained at or above the level established during the performance test.
3. Kiln equipped with a WS	a. Each emission limit in Table 1 to this subpart and each operating limit in Item 3 of Table 2 to this subpart for kilns equipped with WS.	i. Collecting the scrubber pressure drop data according to § 63.8600(a); reducing the scrubber pressure drop data to 3-hour block averages according to § 63.8600(a); maintaining the average scrubber pressure drop for each 3-hour block period at or above the average pressure drop established during the performance test; and ii. Collecting the scrubber liquid pH data according to § 63.8600(a); reducing the scrubber liquid pH data to 3-hour block averages according to § 63.8600(a); maintaining the average scrubber liquid pH for each 3-hour block period at or above the average scrubber liquid pH established during the performance test; and

TABLE 6 TO SUBPART KKKKK OF PART 63.—CONTINUOUS COMPLIANCE WITH EMISSION LIMITATIONS AND WORK PRACTICE STANDARDS—Continued

For each . . .	For the following . . .	You must demonstrate continuous compliance by . . .
		iii. Collecting the scrubber liquid flow rate data according to § 63.8600(a); reducing the scrubber liquid flow rate data to 3-hour block averages according to § 63.8600(a); maintaining the average scrubber liquid flow rate for each 3-hour block period at or above the average scrubber liquid flow rate established during the performance test; and iv. If chemicals are added to the scrubber water, collecting the scrubber chemical feed rate data according to § 63.8600(a); reducing the scrubber chemical feed rate data to 3-hour block averages according to § 63.8600(a); maintaining the average scrubber chemical feed rate for each 3-hour block period at or above the average scrubber chemical feed rate established during the performance test.
4. Existing, new, or reconstructed periodic kiln, tunnel kiln, or roller kiln; each tunnel kiln that would be considered reconstructed but for § 63.8540 (f)(1); and each tunnel kiln that would be considered reconstructed but for § 63.8540(f)(2).	Minimize fuel-based HAP emissions.	i. Maintaining records documenting your use of natural gas, or an equivalent fuel, as the kiln fuel at all times except during periods of natural gas curtailment or supply interruption; and ii. If you intend to use an alternative fuel, submitting 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 § 63.8665; and iii. Submitting a report of alternative fuel use within 10 working days after terminating the use of the alternative fuel, as specified in § 63.8635(g).

As stated in § 63.8635, you must submit each report that applies to you according to the following table:

TABLE 7 TO SUBPART KKKKK OF PART 63.—REQUIREMENTS FOR REPORTS

You must submit . . .	The report must contain . . .	You must submit the report . . .
1. A compliance report	a. If there are no deviations from any emission limitations or work practice standards that apply to you, a statement that there were no deviations from the emission limitations or work practice standards during the reporting period. If there were no periods during which the CMS was out-of-control as specified in your OM&M plan, a statement that there were no periods during which the CMS was out-of-control during the reporting period.	Semiannually according to the requirements in § 63.8635(b).
	b. If you have a deviation from any emission limitation (emission limit, operating limit) during the reporting period, the report must contain the information in § 63.8635(d) or (e). If there were periods during which the CMS was out-of-control, as specified in your OM&M plan, the report must contain the information in § 63.8635(e).	Semiannually according to the requirements in § 63.8635(b).
	c. 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).	Semiannually according to the requirements in § 63.8635(b).
2. An immediate startup, shutdown, and malfunction report if you took actions during a startup, shutdown, or malfunction during the reporting period that are not consistent with your SSMP.	a. Actions taken for the event according to the requirements in § 63.10(d)(5)(ii).	By fax or telephone within 2 working days after starting actions inconsistent with the plan.
	b. The information in § 63.10(d)(5)(ii)	By letter within 7 working days after the end of the event unless you have made alternative arrangements with the permitting authority.
3. A report of alternative fuel use	The information in § 63.8635(g)	If you are subject to the work practice standards specified in Table 3 to this subpart, and you use an alternative fuel to fire an affected kiln, by letter within 10 working days after terminating the use of the alternative fuel.

As stated in § 63.8655, you must comply with the General Provisions in §§ 63.1 through 63.15 that apply to you according to the following table:

TABLE 8 TO SUBPART KKKKK OF PART 63.—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART KKKKK

Citation	Subject	Brief description	Applies to subpart KKKKK
§ 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	Compliance date; circumvention; severability	Yes.
§ 63.5	Construction/Reconstruction	Applicability; applications; approvals	Yes.
§ 63.6(a)	Applicability	General Provisions (GP) apply unless compliance extension; 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 section 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 area sources.	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; for section 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; correct malfunctions as soon as practicable; 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 startup, shutdown, and malfunction (SSM) and SSMP; content of SSMP.	Yes.
§ 63.6(f)(1)	Compliance Except During SSM	You must 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)	Alternative Standard	Procedures for getting an alternative standard	Yes.
§ 63.6(h)	Opacity/VE Standards	Requirements for opacity and VE standards	No, not applicable.
§ 63.6(i)	Compliance Extension	Procedures and criteria for Administrator to grant compliance extension.	Yes.
§ 63.6(j)	Presidential Compliance Exemption	President may exempt source category	Yes.
§ 63.7(a)(1)–(2)	Performance Test Dates	Dates for conducting initial performance testing and other compliance demonstrations; must conduct 180 days after first subject to rule.	Yes.
§ 63.7(a)(3)	Section 114 Authority	Administrator may require a performance test under CAA section 114 at any time.	Yes.
§ 63.7(b)(1)	Notification of Performance Test	Must notify Administrator 60 days before the test.	Yes.
§ 63.7(b)(2)	Notification of Rescheduling	Must notify Administrator 5 days before scheduled date of rescheduled date.	Yes.
§ 63.7(c)	Quality Assurance (QA)/Test Plan	Requirements; test plan approval procedures; performance audit requirements; 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	Performance tests must be conducted under representative conditions.	No, § 63.8595 specifies requirements.
		Cannot conduct performance tests during SSM; not a violation to exceed standard during SSM.	Yes.

TABLE 8 TO SUBPART KKKKK OF PART 63.—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART KKKKK—Continued

Citation	Subject	Brief description	Applies to subpart KKKKK
§ 63.7(e)(2)–(3)	Conditions for Conducting Performance Tests	Must conduct according to subpart and EPA test methods unless Administrator approves alternative; must have at least three test runs of at least 1 hour each; compliance is based on arithmetic mean of three runs; conditions when data from an additional test run can be used.	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; must submit performance test data 60 days after end of test with the notification of compliance status.	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 subpart	Yes.
§ 63.8(a)(2)	Performance Specifications	Performance Specifications in appendix B of 40 CFR part 60 apply.	Yes.
§ 63.8(a)(3)	[Reserved].		
§ 63.8(a)(4)	Monitoring with Flares	Requirements for flares in § 63.11 apply	No, not applicable.
§ 63.8(b)(1)	Monitoring	Must conduct monitoring according to standard unless Administrator approves alternative.	Yes.
§ 63.8(b)(2)–(3)	Multiple Effluents and Multiple Monitoring Systems.	Specific requirements for installing and reporting on monitoring systems.	Yes.
§ 63.8(c)(1)	Monitoring System Operation and Maintenance	Maintenance consistent with good air pollution control practices.	Yes.
§ 63.8(c)(1)(i)	Routine and Predictable SSM	Reporting requirements for SSM when action is described in SSMP.	Yes.
§ 63.8(c)(1)(ii)	SSM not in SSMP	Reporting requirements for SSM when action is not described in SSMP.	Yes.
§ 63.8(c)(1)(iii)	Compliance with Operation and Maintenance Requirements.	How Administrator determines if source complying with operation and maintenance requirements.	Yes.
§ 63.8(c)(2)–(3)	Monitoring System Installation	Must install to get representative emission and parameter measurements.	Yes.
§ 63.8(c)(4)	CMS Requirements	Requirements for CMS	No, §§ 63.8575 and 63.8615 specify requirements.
§ 63.8(c)(5)	Continuous Opacity Monitoring System (COMS) Minimum Procedures.	COMS minimum procedures	No, not applicable.
§ 63.8(c)(6)	CMS Requirements	Zero and high level calibration check requirements.	No, § 63.8575 specifies requirements.
§ 63.8(c)(7)–(8)	CMS Requirements	Out-of-control periods	No, § 63.8575 specifies requirements.
§ 63.8(d)	CMS Quality Control	Requirements for CMS quality control	No, § 63.8575 specifies requirements.
§ 63.8(e)	CMS Performance Evaluation	Requirements for CMS performance evaluation	No, § 63.8575 specifies requirements.
§ 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 test for continuous emission monitoring systems (CEMS).	No, not applicable.
§ 63.8(g)	Data Reduction	COMS and CEMS data reduction requirements	No, not applicable.
§ 63.9(a)	Notification Requirements	Applicability; State delegation	Yes.
§ 63.9(b)	Initial Notifications	Requirements for initial notifications	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	Yes.
§ 63.9(f)	Notification of VE/Opacity Test	Notify Administrator 30 days prior	No, not applicable.
§ 63.9(g)(1)	Additional Notifications When Using CMS	Notification of performance evaluation	Yes.
§ 63.9(g)(2)–(3)	Additional Notifications When Using CMS	Notification of COMS data use; notification that relative accuracy alternative criterion were exceeded..	No, not applicable.

TABLE 8 TO SUBPART KKKKK OF PART 63.—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART KKKKK—Continued

Citation	Subject	Brief description	Applies to subpart KKKKK
§ 63.9(h)	Notification of Compliance Status	Contents; submittal requirements	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	Applicability; general information	Yes.
§ 63.10(b)(1)	General Recordkeeping Requirements	General requirements	Yes.
§ 63.10(b)(2)(i)–(v)	Records Related to SSM	Requirements for SSM records	Yes.
§ 63.10(b)(2)(vi)–(xii) and (xiv).	CMS Records	Records when CMS is malfunctioning, inoperative or out-of-control.	Yes.
§ 63.10(b)(2)(xiii)	Records	Records when using alternative to relative accuracy test.	No, not applicable.
§ 63.10(b)(3)	Records	Applicability Determinations	Yes.
§ 63.10(c)(1)–(15)	Records	Additional records for CMS	No, §§ 63.8575 and 63.8640 specify requirements.
§ 63.10(d)(1) and (2)	General Reporting Requirements	Requirements for reporting; performance test results reporting.	Yes.
§ 63.10(d)(3)	Reporting Opacity or VE Observations	Requirements for reporting opacity and VE	No, not applicable.
§ 63.10(d)(4)	Progress Reports	Must submit progress reports on schedule if under compliance extension.	Yes.
§ 63.10(d)(5)	SSM Reports	Contents and submission	Yes.
§ 63.10(e)(1)–(3)	Additional CMS Reports	Requirements for CMS reporting	No, §§ 63.8575 and 63.8635 specify requirements.
§ 63.10(e)(4)	Reporting COMS data	Requirements for reporting COMS data with performance test data.	No, not applicable.
§ 63.10(f)	Waiver for Recordkeeping/Reporting	Procedures for Administrator to waive	Yes.
§ 63.11	Flares	Requirement for flares	No, not applicable.
§ 63.12	Delegation	State authority to enforce standards	Yes.
§ 63.13	Addresses	Addresses for reports, notifications, requests	Yes.
§ 63.14	Incorporation by Reference	Materials incorporated by reference	Yes.
§ 63.15	Availability of Information	Information availability; confidential information	Yes.

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Part V

Environmental Protection Agency

40 CFR Part 63
National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[EPA–HQ–OAR–2002–0058; FRL–9272–8]

RIN 2060–AQ25

National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: On September 13, 2004, under authority of section 112 of the Clean Air Act, EPA promulgated national emission standards for hazardous air pollutants for new and existing industrial/commercial/institutional boilers and process heaters. On June 19, 2007, the United States Court of Appeals for the District of Columbia Circuit vacated and remanded the standards.

In response to the Court's vacatur and remand, EPA is, in this action, establishing emission standards that will require industrial/commercial/institutional boilers and process heaters located at major sources to meet hazardous air pollutants standards reflecting the application of the maximum achievable control technology. This rule protects air quality and promotes public health by reducing emissions of the hazardous air pollutants listed in section 112(b)(1) of the Clean Air Act.

DATES: This final rule is effective on May 20, 2011. The incorporation by reference of certain publications listed in this rule is approved by the Director of the Federal Register as of May 20, 2011.

ADDRESSES: EPA established a single docket under Docket ID No. EPA–HQ–OAR–2002–0058 for this action. All documents in the docket are listed on the *http://www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, *e.g.,* confidential business information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through *http://www.regulations.gov* or in hard copy at EPA's Docket Center, Public Reading Room, EPA West Building, Room 3334, 1301 Constitution Avenue, NW., Washington, DC 20004. This Docket Facility is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1741.

FOR FURTHER INFORMATION CONTACT: Mr. Brian Shrager, Energy Strategies Group, Sector Policies and Programs Division, (D243–01), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; Telephone number: (919) 541–7689; Fax number (919) 541–5450; E-mail address: *shrager.brian@epa.gov.*

SUPPLEMENTARY INFORMATION: The information presented in this preamble is organized as follows:

I. General Information

A. Does this action apply to me?

The regulated categories and entities potentially affected by the final standards include:

Category	NAICS code[1]	Examples of potentially regulated entities
Any industry using a boiler or process heater as defined in the final rule.	211	Extractors of crude petroleum and natural gas.

Category	NAICS code[1]	Examples of potentially regulated entities
	321	Manufacturers of lumber and wood products.
	322	Pulp and paper mills.
	325	Chemical manufacturers.
	324	Petroleum refineries, and manufacturers of coal products.
	316, 326, 339	Manufacturers of rubber and miscellaneous plastic products.
	331	Steel works, blast furnaces.
	332	Electroplating, plating, polishing, anodizing, and coloring.
	336	Manufacturers of motor vehicle parts and accessories.
	221	Electric, gas, and sanitary services.
	622	Health services.
	611	Educational services.

[1] North American Industry Classification System.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be affected by this action. To determine whether your facility, company, business, organization, etc., would be regulated by this action, you should examine the applicability criteria in 40 CFR 63.7485 of subpart DDDDD (National Emission Standards for Hazardous Air Pollutants (NESHAP) for Industrial, Commercial, and Institution Boilers and Process Heaters). If you have any questions regarding the applicability of this action to a particular entity, consult either the air permitting authority for the entity or your EPA regional representative as listed in 40 CFR 63.13 of subpart A (General Provisions).

B. Where can I get a copy of this document?

In addition to being available in the docket, an electronic copy of this action will also be available on the Worldwide Web (WWW) through the Technology Transfer Network (TTN). Following signature, a copy of the action will be posted on the TTN's 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.

C. Judicial Review

Under the Clean Air Act (CAA) section 307(b)(1), judicial review of this final rule is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit by May 20, 2011. Under CAA section 307(d)(7)(B), only an objection to this final rule that was raised with reasonable specificity during the period for public comment can be raised during judicial review. This section also provides a mechanism for us to convene a proceeding for reconsideration, "[i]f the person raising an objection can demonstrate to EPA that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of this rule." Any person seeking to make such a demonstration to us should submit a Petition for Reconsideration to the Office of the Administrator, Environmental Protection Agency, Room 3000, Ariel Rios Building, 1200 Pennsylvania Ave., NW., Washington, DC 20004, with a copy to the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20004. Note, under CAA section 307(b)(2), the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by EPA to enforce these requirements.

II. Background Information

A. What is the statutory authority for this final rule?

Section 112(d) of the CAA requires EPA to set emissions standards for hazardous air pollutants (HAP) emitted by major stationary sources based on the performance of the maximum achievable control technology (MACT). The MACT standards for existing sources must be at least as stringent as the average emissions limitation achieved by the best performing 12 percent of existing sources (for which the Administrator has emissions information) or the best performing 5 sources for source categories with less than 30 sources (CAA section 112(d)(3)(A) and (B)). This level of minimum stringency is called the MACT floor. For new sources, MACT standards must be at least as stringent as the control level achieved in practice by the best controlled similar source (CAA section 112(d)(3)). EPA also must consider more stringent "beyond-the-floor" control options. When considering beyond-the-floor options, EPA must consider not only the maximum degree of reduction in emissions of HAP, but must take into account costs, energy, and nonair environmental impacts when doing so.

With respect to alkylated lead compounds; polycyclic organic matter (POM); hexachlorobenzene; mercury (Hg); polychlorinated biphenyls; 2,3,7,8-tetrachlorodibenzofurans; and 2,3,7,8-tetrachlorodibenzo-p-dioxin, the CAA section 112(c)(6) requires EPA to list categories and subcategories of sources assuring that sources accounting for not less than 90 percent of the aggregate emissions of each such pollutant are subject to standards under subsection 112(d)(2) or (d)(4). Standards established under CAA section 112(d)(2) must reflect the performance of MACT. "Industrial Coal Combustion," "Industrial Oil Combustion," "Industrial Wood/Wood Residue Combustion," "Commercial Coal Combustion," "Commercial Oil Combustion," and "Commercial Wood/Wood Residue Combustion" are listed as source categories for regulation pursuant to CAA section 112(c)(6) due to emissions of POM and Hg (63 FR 17838, 17848, April 10, 1998). In the documentation for the 112(c)(6) listing, the commercial fuel combustion categories included institutional fuel combustion ("1990 Emissions Inventory of Section 112(c)(6) Pollutants, Final Report," April 1998).

CAA section 129(a)(1)(A) requires EPA to establish specific performance standards, including emission limitations, for "solid waste incineration units" generally, and, in particular, for "solid waste incineration units combusting commercial or industrial waste" (section 129(a)(1)(D)). Section 129 defines "solid waste incineration unit" as "a distinct operating unit of any facility which combusts any solid waste material from commercial or industrial establishments or the general public."

Section 129(g)(1). Section 129 also provides that "solid waste" shall have the meaning established by EPA pursuant to its authority under the Resource Conservation and Recovery Act. Section 129(g)(6).

In *Natural Resources Defense Council* v. *EPA,* 489 F. 3d 1250, 1257–61 (D.C. Cir. 2007), the court vacated the Commercial and Industrial Solid Waste Incineration (CISWI) Definitions Rule, 70 FR 55568 (September 22, 2005), which EPA issued pursuant to CAA section 129(a)(1)(D). In that rule, EPA defined the term "commercial or industrial solid waste incineration unit" to mean a combustion unit that combusts "commercial or industrial waste." The CISWI definitions rule defined "commercial or industrial waste" to mean waste combusted at a unit that does not recover thermal energy from the combustion for a useful purpose. Under these definitions, only those units that combusted commercial or industrial waste and were not designed to, or did not operate to, recover thermal energy from the combustion would be subject to section 129 standards. The District of Columbia Circuit (DC Circuit) rejected the definitions contained in the CISWI Definitions Rule and interpreted the term "solid waste incineration unit" in CAA section 129(g)(1) "to unambiguously include among the incineration units subject to its standards any facility that combusts any commercial or industrial solid waste material at all—subject to the four statutory exceptions identified in [CAA section 129(g)(1).]" *NRDC* v. *EPA,* 489 F.3d 1250, 1257–58. A more detailed discussion of this decision, as well as other court decisions relevant to today's action, can be found in the June 4, 2010, preamble to the proposed rule. See 75 FR 32009.

CAA section 129 covers any facility that combusts any solid waste; CAA section 129(g)(6) directs the Agency to the Resource Conservation and Recovery Act (RCRA) in terms of the definition of solid waste. In this **Federal Register**, EPA is issuing a definition of solid waste for purposes of Subtitle D of RCRA. If a unit combusts solid waste, it is subject to CAA section 129 of the Act, unless it falls within one of the four specified exceptions in CAA section 129(g).

The solid waste definitional rulemaking under RCRA is being finalized in a parallel action and is relevant to this proceeding because some industrial, commercial, or institutional boilers and process heaters combust secondary materials as alternative fuels. If industrial, commercial, or institutional boilers or process heaters combust secondary materials that are solid waste under the final definitional rule, those units would be subject to emission standards issued under section 129. The units subject to this final rule include those industrial, commercial, or institutional boilers and process heaters that do not combust solid waste, as well as boilers and process heaters that combust solid waste but qualify for one of the statutory exclusions contained in section 129(g)(1). EPA recognizes that it has imperfect information on the exact nature of the secondary materials which boilers and process heaters combust, including, for example, how much processing of such materials occurs, if any. We used the information currently available to the Agency to determine which units combust solid waste materials and, therefore, are subject to CAA section 129, and which units do not combust solid waste (or qualify for an exclusion from section 129) and, therefore, are subject to CAA section 112.

B. EPA's Response to the Vacatur

A description of EPA's information collection efforts and a description of the development of EPA's proposed response to the *NRDC* v. *EPA* mandate is contained in the preamble to the proposed rule. *See* 75 FR 32010–32011. After consideration of public comments on the proposed rule, we have made appropriate revisions to the final rule, and a description of the major changes is provided in this preamble. The changes reflect EPA's consideration of public comments and the consideration of additional information and emissions data provided through the public comment process. The changes also reflect adjustments to the definition of non-hazardous solid waste as set forth in a parallel final action. That final rule contains some revisions to the definition of non-hazardous solid waste proposed by EPA in June 2010. Accordingly, the population of combustion units subject to CAA section 129 (because they combust solid waste) and the population of boilers and process heaters subject to CAA section 112 (because they do not combust solid waste) were established considering the final solid waste definition issued today. We used the updated inventories and all available data, as appropriate, to develop the final standards for boilers and process heaters under CAA section 112 and, in a separate parallel action, the final standards for commercial and industrial solid waste incineration units covered by CAA section 129. We used all of the appropriate information available to the Administrator to calculate the MACT floors, set emission limits, and evaluate the emission impacts of various regulatory options for these final rulemakings.

C. What is the relationship between this final rule and other combustion rules?

This final rule addresses the combustion of non-solid waste materials in boilers and process heaters located at major sources of HAP. If an owner or operator of an affected source subject to these standards were to start combusting a solid waste (as defined by the Administrator under RCRA), the affected source would cease to be subject to this action and would instead be subject to regulation under CAA section 129. A rulemaking under CAA section 129 is being finalized in a parallel action and is relevant to this action because it would apply to boilers and process heaters that combust any solid waste and are located at a major source. In this final boiler rulemaking, EPA is providing specific language to ensure clarity regarding the necessary steps that must be followed for combustion units that begin combusting non-hazardous solid waste materials and become subject to section 129 standards instead of section 112 standards or combustion units that discontinue combustion of non-hazardous solid waste materials and become subject to section 112 standards instead of section 129 standards.

In addition to combustion units that may switch between the section 112 boiler standards and the section 129 incinerator standards, there are certain instances where boilers and process heaters are already regulated under other MACT standards. In such cases, the boilers and process heaters that are already subject to another MACT standard are not subject to the boiler standards.

In 1986, EPA codified new source performance standards (NSPS) for industrial boilers (40 CFR part 60, subparts Db and Dc) and portions of those standards were revised in 1999 and 2006. The NSPS regulates emissions of particulate matter (PM), sulfur dioxide (SO_2), and nitrogen oxide (NO_X) from boilers constructed after June 19, 1984. Sources subject to the NSPS will also be subject to the final CAA section 112(d) standards for boilers and process heaters because the section 112(d) standards regulate HAP emissions while the NSPS do not. However, in developing this final rule, we considered the monitoring requirements, testing requirements, and recordkeeping requirements of the NSPS to avoid duplicating requirements.

D. What are the health effects of pollutants emitted from industrial/commercial/institutional boilers and process heaters?

This final rule protects air quality and promotes the public health by reducing emissions of some of the HAP listed in CAA section 112(b)(1). As noted above, emissions data collected during development of the rule show that hydrogen chloride (HCl) emissions represent the predominant HAP emitted by industrial, commercial, and institutional (ICI) boilers, accounting for 69 percent of the total HAP emissions.[1] ICI boilers and process heaters also emit lesser amounts of hydrogen fluoride, accounting for about 21 percent of total HAP emissions, and metals (arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese (Mn), Hg, nickel, and selenium) accounting for about 6 percent of total HAP emissions. Organic HAP (formaldehyde, POM, acetaldehyde, benzene) account for about 4 percent of total HAP emissions. Exposure to these HAP, depending on exposure duration and levels of exposures, can be associated with a variety of adverse health effects. These adverse health effects may include, for example, irritation of the lung, skin, and mucus membranes, effects on the central nervous system, damage to the kidneys, and alimentary effects such as nausea and vomiting. We have classified two of the HAP as human carcinogens (arsenic and chromium VI) and four as probable human carcinogens (cadmium, lead, dioxins/furans, and nickel). We do not know the extent to which the adverse health effects described above occur in the populations surrounding these facilities. However, to the extent the adverse effects do occur, this final rule would reduce emissions and subsequent exposures.

E. What are the costs and benefits of this final rule?

EPA estimated the costs and benefits associated with the final rule, and the results are shown in the following table. For more information on the costs and benefits for this rule, *see* the Regulatory Impact Analysis (RIA).

SUMMARY OF THE MONETIZED BENEFITS, SOCIAL COSTS, AND NET BENEFITS FOR THE BOILER MACT IN 2014

[Millions of 2008$]

	3% Discount rate	7% Discount rate
Selected		
Total Monetized Benefits[2]	$22,000 to $54,000	$20,000 to $49,000
Total Social Costs[3]	$1,500	$1,500
Net Benefits	$20,500 to $52,500	$18,500 to $47,500
Non-monetized Benefits	112,000 tons of CO, 30,000 tons of HCl, 820 tons of HF, 2,800 pounds of Hg.	
	2,700 tons of other metals, 23 grams of dioxins/furans (TEQ), Health effects from SO_2 exposure, Ecosystem effects, Visibility impairment.	
Alternative		
Total Monetized Benefits[2]	$18,000 to $43,000	$16,000 to $39,000
Total Social Costs[3]	$1,900	$1,900
Net Benefits	$16,100 to $41,100	$14,100 to $37,100
Non-monetized Benefits	112,000 tons of CO, 22,000 tons of HCl, 620 tons of HF, 2,400 pounds of Hg, 2,600 tons of other metals, 23 grams of dioxins/furans (TEQ), Health effects from SO_2 exposure, Ecosystem effects, Visibility impairment.	

[1] All estimates are for the implementation year (2014), and are rounded to two significant figures. These results include units anticipated to come online and the lowest cost disposal assumption.

[2] The total monetized benefits reflect the human health benefits associated with reducing exposure to $PM_{2.5}$ through reductions of directly emitted $PM_{2.5}$ and $PM_{2.5}$ precursors such as SO_2, as well as reducing exposure to ozone through reductions of VOCs. It is important to note that the monetized benefits include many but not all health effects associated with $PM_{2.5}$ exposure. Benefits are shown as a range from Pope *et al.* (2002) to Laden *et al.* (2006). These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because there is no clear scientific evidence that would support the development of differential effects estimates by particle type. These estimates include energy disbenefits valued at $23 million for the selected option and $35 million for the alternative option. Ozone benefits are valued at $3.6 to $15 million for both options.

[3] The methodology used to estimate social costs for one year in the multimarket model using surplus changes results in the same social costs for both discount rates.

III. Summary of This Final Rule

This section summarizes the requirements of this action. Section IV below provides a summary of the significant changes to this final rule following proposal.

A. What is the source category regulated by this final rule?

ICI boilers and process heaters located at major sources of HAP are regulated by this final rule. Waste heat boilers and boilers and process heaters that combust solid waste, except for specific exceptions to the definition of a solid waste incineration unit outlined in section 129(g)(1), are not subject to this final rule.

B. What is the affected source?

This final rule affects industrial boilers, institutional boilers, commercial boilers, and process heaters. A process heater is defined as a unit in which the combustion gases do not directly come into contact with process material or gases in the combustion chamber (*e.g.,* indirect fired). A boiler is defined as an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water.

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[1] *See* Memorandum “Methodology for Estimating Impacts from Industrial, Commercial, Institutional Boilers and Process Heaters at Major Sources of Hazardous Air Pollutant Emissions” located in the docket.

C. What are the pollutants regulated by this final rule?

This final rule regulates HCl (as a surrogate for acid gas HAP), PM (as a surrogate for non-Hg HAP metals), carbon monoxide (CO) (as a surrogate for non-dioxin/furan organic HAP), Hg, and dioxin/furan emissions from boilers and process heaters.

D. What emission limits and work practice standards must I meet?

You must meet the emission limits presented in Table 1 of this preamble. This final rule includes 15 subcategories. Emission limits are established for new and existing sources for each of the subcategories, which are based on unit design.

Metallic HAP (regulated using PM as a surrogate), HCl, and Hg are "fuel-based pollutants" that are a direct result of contaminants in the fuels that are combusted. For those pollutants, if your new or existing unit combusts at least 10 percent solid fuel on an annual basis, your unit is subject to emission limits that are based on data from all of the solid fuel-fired combustor designs. If your new or existing unit combusts at least 10 percent liquid fuel and less than 10 percent solid fuel and your facility is located in the continental United States, your unit is subject to the liquid fuel emission limits for the fuel-based pollutants. If your facility is located outside of North America (referred to as a non-continental unit for the remainder of the preamble and in this final rule) and your new or existing unit combusts at least 10 percent liquid fuel and less than 10 percent solid fuel, your unit is subject to the non-continental liquid fuel emission limits for the fuel-based pollutants. Finally, for the fuel-based pollutants, if your unit combusts gaseous fuel that does not qualify as a "Gas 1" fuel, your unit is subject to the Gas 2 emission limits in Table 1 of this preamble. If your unit is a Gas 1 unit (that is, it combusts only natural gas, refinery gas, or equivalent fuel (other gas that qualifies as Gas 1 fuel)), with limited exceptions for gas curtailments and emergencies, your unit is subject to a work practice standard that requires an annual tune-up in lieu of emission limits.

For the combustion-based pollutants, CO (used as a surrogate for non-dioxin organic HAP) and dioxin/furan, your unit is subject to the emission limits for the design-based subcategories shown in Table 1 of this preamble. If your new or existing boiler or process heater burns at least 10 percent biomass on an annual average heat input[2] basis, the unit is in one of the biomass subcategories. If your new or existing boiler or process heater burns at least 10 percent coal, on an annual average heat input basis, and less than 10 percent biomass, on an annual average heat input basis, the unit is in one of the coal subcategories. If your facility is located in the continental United States and your new or existing boiler or process heater burns at least 10 percent liquid fuel (such as distillate oil, residual oil) and less than 10 percent coal and less than 10 percent biomass, on an annual average heat input basis, your unit is in the liquid subcategory. If your non-continental new or existing boiler or process heater burns at least 10 percent liquid fuel (such as distillate oil, residual oil) and less than 10 percent coal and less than 10 percent biomass, on an annual average heat input basis, your unit is in the non-continental liquid subcategory. Finally, for the combustion-based pollutants, if your unit combusts gaseous fuel that does not qualify as a "Gas 1" fuel, your unit is subject to the Gas 2 emission limits in Table 1. If your unit combusts only natural gas, refinery gas, or equivalent fuel (other gas that qualifies as Gas 1 fuel), with limited exceptions for gas curtailment and emergencies, your unit is subject to a work practice standard that requires an annual tune-up in lieu of emission limits.

TABLE 1—EMISSION LIMITS FOR BOILERS AND PROCESS HEATERS

[Pounds per million British thermal units]

Subcategory	Particulate matter (PM)	Hydrogen chloride (HCl)	Mercury (Hg)	Carbon monoxide (CO) (ppm @3% oxygen)	Dioxin/furan (TEQ) (ng/dscm)
Existing—Coal Stoker	0.039	0.035	0.0000046	270	0.003
Existing—Coal Fluidized Bed	0.039	0.035	0.0000046	82	0.002
Existing—Pulverized Coal	0.039	0.035	0.0000046	160	0.004
Existing—Biomass Stoker/other	0.039	0.035	0.0000046	490	0.005
Existing—Biomass Fluidized Bed	0.039	0.035	0.0000046	430	0.02
Existing—Biomass Dutch Oven/Suspension Burner	0.039	0.035	0.0000046	470	0.2
Existing—Biomass Fuel Cells	0.039	0.035	0.0000046	690	4
Existing—Biomass Suspension/Grate	0.039	0.035	0.0000046	3,500	0.2
Existing—Liquid	0.0075	0.00033	0.0000035	10	4
Existing—Gas 2 (Other Process Gases)	0.043	0.0017	0.000013	9.0	0.08
Existing—non-continental liquid	0.0075	0.00033	0.00000078	160	4
New—Coal Stoker	0.0011	0.0022	0.0000035	6	0.003
New—Coal Fluidized Bed	0.0011	0.0022	0.0000035	18	0.002
New—Pulverized Coal	0.0011	0.0022	0.0000035	12	0.003
New—Biomass Stoker	0.0011	0.0022	0.0000035	160	0.005
New—Biomass Fluidized Bed	0.0011	0.0022	0.0000035	260	0.02
New—Biomass Dutch Oven/Suspension Burner	0.0011	0.0022	0.0000035	470	0.2
New—Biomass Fuel Cells	0.0011	0.0022	0.0000035	470	0.003
New—Biomass Suspension/Grate	0.0011	0.0022	0.0000035	1,500	0.2
New—Liquid	0.0013	0.00033	0.00000021	3	0.002
New—Gas 2 (Other Process Gases)	0.0067	0.0017	0.0000079	3	0.08
New—non-continental liquid	0.0013	0.00033	0.00000078	51	0.002

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[2] Heat input means heat derived from combustion of fuel in a boiler or process heater and does not include the heat derived from preheated combustion air, recirculated flue gases or exhaust from other sources (such as stationary gas turbines, internal combustion engines, and kilns).

The emission limits in Table 1 apply only to new and existing boilers and process heaters that have a designed heat input capacity of 10 million British thermal units per hour (MMBtu/hr) or greater. We also are providing optional output-based standards in this final rule. Pursuant to CAA section 112(h), we are requiring a work practice standard for four particular classes of boilers and process heaters: New and existing units that have a designed heat input capacity of less than 10 MMBtu/hr, and new and existing units in the Gas 1 (natural gas/refinery gas) subcategory and in the metal process furnaces subcategory. The work practice standard for these boilers and process heaters requires the implementation of a tune-up program as described in section III.F of this preamble.

We are also finalizing a beyond-the-floor standard for all existing major source facilities having affected boilers or process heaters that would require the performance of a one-time energy assessment, as described in section III.F of this preamble, by qualified personnel, on the affected boilers and facility to identify any cost-effective energy conservation measures.

E. What are the requirements during periods of startup, shutdown, and malfunction?

Consistent with *Sierra Club* v. *EPA*, EPA has established standards in this final rule that apply at all times. In establishing the standards in this final rule, EPA has taken into account startup and shutdown periods and, for the reasons explained below, has established different standards for those periods.

EPA has revised this final rule to require sources to meet a work practice standard, which requires following the manufacturer's recommended procedures for minimizing periods of startup and shutdown, for all subcategories of new and existing boilers and process heaters (that would otherwise be subject to numeric emission limits) during periods of startup and shutdown. As discussed in Section V.F of this preamble, we considered whether performance testing, and therefore, enforcement of numeric emission limits, would be practicable during periods of startup and shutdown. EPA determined that it is not technically feasible to complete stack testing—in particular, to repeat the multiple required test runs—during periods of startup and shutdown due to physical limitations and the short duration of startup and shutdown periods. Therefore, we have established the separate work practice standard for periods of startup and shutdown.

Periods of startup, normal operations, and shutdown are all predictable and routine aspects of a source's operations. However, by contrast, malfunction is defined as a "sudden, infrequent, and not reasonably preventable failure of air pollution control and monitoring equipment, process equipment or a process to operate in a normal or usual manner * * * "(40 CFR 63.2). EPA has determined that malfunctions should not be viewed as a distinct operating mode and, therefore, any emissions that occur at such times do not need to be factored into development of CAA section 112(d) standards, which, once promulgated, apply at all times. In *Mossville Environmental Action Now* v. *EPA*, 370 F.3d 1232, 1242 (D.C. Cir. 2004), the court upheld as reasonable standards that had factored in variability of emissions under all operating conditions. However, nothing in section 112(d) or in case law requires that EPA anticipate and account for the innumerable types of potential malfunction events in setting emission standards. *See, Weyerhaeuser* v. *Costle*, 590 F.2d 1011, 1058 (D.C. Cir. 1978) ("In the nature of things, no general limit, individual permit, or even any upset provision can anticipate all upset situations. After a certain point, the transgression of regulatory limits caused by 'uncontrollable acts of third parties,' such as strikes, sabotage, operator intoxication or insanity, and a variety of other eventualities, must be a matter for the administrative exercise of case-by-case enforcement discretion, not for specification in advance by regulation.")

Further, it is reasonable to interpret section 112(d) as not requiring EPA to account for malfunctions in setting emissions standards. For example, we note that Section 112 uses the concept of "best performing" sources in defining MACT, the level of stringency that major source standards must meet. Applying the concept of "best performing" to a source that is malfunctioning presents significant difficulties. The goal of best performing sources is to operate in such a way as to avoid malfunctions of their units.

Moreover, even if malfunctions were considered a distinct operating mode, we believe it would be impracticable to take malfunctions into account in setting CAA section 112(d) standards for boilers and process heaters. As noted above, by definition, malfunctions are sudden and unexpected events and it would be difficult to set a standard that takes into account the myriad different types of malfunctions that can occur across all sources in the category. Moreover, malfunctions can vary in frequency, degree, and duration, further complicating standard setting.

In the event that a source fails to comply with the applicable CAA section 112(d) standards as a result of a malfunction event, EPA would determine an appropriate response based on, among other things, the good faith efforts of the source to minimize emissions during malfunction periods, including preventative and corrective actions, as well as root cause analyses to ascertain and rectify excess emissions. EPA would also consider whether the source's failure to comply with the CAA section 112(d) standard was, in fact, "sudden, infrequent, not reasonably preventable" and was not instead "caused in part by poor maintenance or careless operation." 40 CFR 63.2 (definition of malfunction).

Finally, EPA recognizes that even equipment that is properly designed and maintained can sometimes fail and that such failure can sometimes cause an exceedance of the relevant emission standard. (*See, e.g.,* State Implementation Plans: Policy Regarding Excessive Emissions During Malfunctions, Startup, and Shutdown (Sept. 20, 1999); Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions (Feb. 15, 1983)). EPA is, therefore, adding to this final rule an affirmative defense to civil penalties for exceedances of numerical emission limits that are caused by malfunctions. *See* 40 CFR 63.7575 (defining "affirmative defense" to mean, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.). We also have added other regulatory provisions to specify the elements that are necessary to establish this affirmative defense; the source must prove by a preponderance of the evidence that it has met all of the elements set forth in 63.7501. (*See* 40 CFR 22.24). The criteria ensure that the affirmative defense is available only where the event that causes an exceedance of the emission limit meets the narrow definition of malfunction in 40 CFR 63.2 (sudden, infrequent, not reasonably preventable and not caused by poor maintenance and or careless operation). For example, to successfully assert the affirmative defense, the source must prove by a preponderance of the evidence that excess emissions "[w]ere caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner * * *.” The criteria also are designed to ensure that steps are taken to correct the malfunction, to minimize emissions in accordance with section 63.7500(a)(3) and to prevent future malfunctions. For example, the source must prove by a preponderance of the evidence that “[r]epairs were made as expeditiously as possible when the applicable emission limitations were being exceeded * * *” and that “[a]ll possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment and human health * * *.” In any judicial or administrative proceeding, the Administrator may challenge the assertion of the affirmative defense and, if the respondent has not met its burden of proving all of the requirements in the affirmative defense, appropriate penalties may be assessed in accordance with Section 113 of the CAA (*see also* 40 CFR 22.77).

F. What are the testing and initial compliance requirements?

We are requiring that the owner or operator of a new or existing boiler or process heater must conduct performance tests to demonstrate compliance with all applicable emission limits. Affected units would be required to conduct the following compliance tests where applicable:

(1) Conduct initial and annual stack tests to determine compliance with the PM emission limits using EPA Method 5 or 17.

(2) Conduct initial and annual stack tests to determine compliance with the Hg emission limits using EPA method 29 or ASTM–D6784–02 (Ontario Hydro Method).

(3) Conduct initial and annual stack tests to determine compliance with the HCl emission limits using EPA Method 26A or EPA Method 26 (if no entrained water droplets in the sample).

(4) Use EPA Method 19 to convert measured concentration values to pound per million Btu values.

(5) Conduct initial and annual test to determine compliance with the CO emission limits using EPA Method 10.

(6) Conduct initial test to determine compliance with the dioxin/furan emission limits using EPA Method 23.

As part of the initial compliance demonstration, we are requiring that you monitor specified operating parameters during the initial performance tests that you would conduct to demonstrate compliance with the PM, Hg, HCl, CO, and dioxin/furan emission limits. You must calculate the average hourly parameter values measured during each test run over the three run performance test. The lowest or highest hourly average of the three test run values (depending on the parameter measured) for each applicable parameter would establish the site-specific operating limit. The applicable operating parameters for which operating limits would be required to be established are based on the emissions limits applicable to your unit as well as the types of add-on controls on the unit. The following is a summary of the operating limits that we are requiring to be established for the various types of the following units:

(1) For boilers and process heaters with wet PM scrubbers, you must measure pressure drop and liquid flow rate of the scrubber during the performance test, and calculate the average hourly values during each test run. The lowest hourly average determined during the three test runs establishes your minimum site-specific pressure drop and liquid flow rate operating levels.

(2) If you are complying with an HCl emission limit using a wet acid gas scrubber, you must measure pH and liquid flow rate of the scrubber sorbent during the performance test, and calculate the average hourly values during each test run of the performance test for HCl and determine the lowest hourly average of the pH and liquid flow rate for each test run for the performance test. This establishes your minimum pH and liquid flow rate operating limits.

(3) For boilers and process heaters with sorbent injection, you must measure the sorbent injection rate for each acid gas sorbent used during the performance tests for HCl and for activated carbon for Hg and dioxin/furan and calculate the hourly average for each sorbent injection rate during each test run. The lowest hourly average measured during the performance tests becomes your site-specific minimum sorbent injection rate operating limit. If different acid gas sorbents and/or injection rates are used during the HCl test, the lowest hourly average value for each sorbent becomes your site-specific operating limit. When your unit operates at lower loads, multiply your sorbent injection rate by the load fraction (operating heat input divided by the average heat input during your last compliance test for the appropriate pollutant) to determine the required parameter value.

(4) For boilers and process heaters with fabric filters not subject to PM Continuous Emission Monitoring System (CEMS) or continuous compliance with an opacity limit (*i.e.,* COMS), 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 unless a CEMS is installed to measure PM.

(5) For boilers and process heaters with electrostatic precipitators (ESP) not subject to PM CEMS or continuous compliance with an opacity limit (*i.e.,* COMS) and you must measure the secondary voltage and secondary current of the ESP collection fields during the Hg and PM performance test. You then calculate the average total secondary electric power value from these parameters for each test run. The lowest average total secondary electric power measured during the three test runs establishes your site-specific minimum operating limit for the ESP.

(6) For boilers and process heaters that choose to demonstrate compliance with the Hg emission limit on the basis of fuel analysis, you are required to measure the Hg content of the inlet fuel that was burned during the Hg performance test. This value is your maximum fuel inlet Hg operating limit.

(7) For boilers and process heaters that choose to demonstrate compliance with the HCl emission limit on the basis of fuel analysis, you are required to measure the chlorine content of the inlet fuel that was burned during the HCl performance test. This value is your maximum fuel inlet chlorine operating limit.

(8) For boilers and process heaters that are subject to a CO emission limit and a dioxin/furan emission limit, you are required to measure the oxygen concentration in the flue gas during the initial CO and dioxin/furan performance test. The lowest hourly average oxygen concentration measured during the most recent performance test is your operating limit, and your unit must operate at or above your operating limit on a 12-hour block average basis.

These operating limits do not apply to owners or operators of boilers or process heaters having a heat input capacity of less than 10 MMBtu/hr or boilers or process heaters of any size which combust natural gas or other clean gas, metal process furnaces, or limited use units, as discussed in section IV.D.3 of this preamble. Instead, owners or operators of such boilers and process heaters shall submit to the delegated authority or EPA, as appropriate, if requested, documentation that a tune-up meeting the requirements of this final rule was conducted. In order to comply with the work practice standard, a tune-up procedure must include the following:

(1) Inspect the burner, and clean or replace any components of the burner as necessary,

(2) Inspect the flame pattern and make any adjustments to the burner necessary to optimize the flame pattern consistent with the manufacturer's specifications,

(3) Inspect the system controlling the air-to-fuel ratio, and ensure that it is correctly calibrated and functioning properly,

(4) Optimize total emissions of CO consistent with the manufacturer's specifications,

(5) Measure the concentration in the effluent stream of CO in parts per million by volume dry (ppmvd), before and after the adjustments are made,

(6) Submit to the delegated authority or EPA an annual report containing the concentrations of CO in the effluent stream in ppmvd, and oxygen in percent dry basis, measured before and after the adjustments of the boiler, a description of any corrective actions taken as a part of the combustion adjustment, and the type and amount of fuel used over the 12 months prior to the annual adjustment.

Further, all owners or operators of major source facilities having boilers and process heaters subject to this final rule are required to submit to the delegated authority or EPA, as appropriate, documentation that an energy assessment was performed, by a qualified energy assessor, and the cost-effective energy conservation measures indentified.

G. What are the continuous compliance requirements?

To demonstrate continuous compliance with the emission limitations, we are requiring the following:

(1) For units combusting coal, biomass, or residual fuel oil (*i.e.,* No 4, 5 or 6 fuel oil) with heat input capacities of less than 250 MMBtu/hr that do not use a wet scrubber, we are requiring that opacity levels be maintained to less than 10 percent (daily average) for existing and new units with applicable emission limits. Or, if the unit is controlled with a fabric filter, instead of continuous monitoring of opacity, the fabric filter must 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 (unless a PM CEMS is used).

(2) For units combusting coal, biomass, or residual oil with heat input capacities of 250 MMBtu/hr or greater, we are requiring that PM CEMS be installed and operated and that PM levels (monthly average) be maintained below the applicable PM limit.

(3) For boilers and process heaters with wet PM scrubbers, we are requiring that you monitor pressure drop and liquid flow rate of the scrubber and maintain the 12-hour block averages at or above the operating limits established during the performance test to demonstrate continuous compliance with the PM emission limits.

(4) For boilers and process heaters with wet acid gas scrubbers, you must monitor the pH and liquid flow rate of the scrubber and maintain the 12-hour block average at or above the operating limits established during the most recent performance test to demonstrate continuous compliance with the HCl emission limits.

(5) For boilers and process heaters with dry scrubbers, we are requiring that you continuously monitor the sorbent injection rate and maintain it at or above the operating limits, which include an adjustment for load, established during the performance tests. When your unit operates at lower loads, multiply your sorbent injection rate by the load fraction (operating load divided by the load during your last compliance test for the appropriate pollutant) to determine the required parameter value.

(6) For boilers and process heaters having heat input capacities of less than 250 MMBtu/hr with an ESP, we are requiring that you monitor the voltage and current of the ESP collection plates and maintain the 12-hour block total secondary electric power averages at or above the operating limits established during the Hg or PM performance test.

(7) For units that choose to comply with either the Hg emission limit or the HCl emission limit based on fuel analysis rather than on performance testing, you must maintain monthly fuel records that demonstrate that you burned no new fuels or fuels from a new supplier such that the Hg content or the chlorine content of the inlet fuel was maintained at or below your maximum fuel Hg content operating limit or your chlorine content operating limit set during the performance tests. If you plan to burn a new fuel, a fuel from a new mixture, or a new supplier's fuel that differs from what was burned during the initial performance tests, then you must recalculate the maximum Hg input and/or the maximum chlorine input anticipated from the new fuels based on supplier data or own fuel analysis, using the methodology specified in Table 6 of this final rule. If the results of recalculating the inputs exceed the average content levels established during the initial test then, you must conduct a new performance test(s) to demonstrate continuous compliance with the applicable emission limit.

(8) For all boilers and process heaters, except those that are exempt from the incinerator standards under section 129 because they are qualifying facilities burning a homogeneous waste stream, you must maintain records of fuel use that demonstrate that your fuel was not solid waste.

(9) For boilers and process heaters with an oxygen monitor installed for this final rule, you must maintain an oxygen concentration level, on a 12-hour block average basis, no less than lowest hourly average oxygen concentration measured during the most recent performance test.

(10) For boilers and process heaters that demonstrate compliance using a performance test. You must maintain an operating load no greater than 110 percent of the operating load established during the performance test.

If an owner or operator would like to use a control device other than the ones specified in this section to comply with this final rule, the owner/operator should follow the requirements in 40 CFR 63.8(f), which presents the procedure for submitting a request to the Administrator to use alternative monitoring.

H. What are the notification, recordkeeping and reporting requirements?

All new and existing sources are required to comply with certain requirements of the General Provisions (40 CFR part 63, subpart A), which are identified in Table 10 of this final rule. The General Provisions include specific requirements for notifications, recordkeeping, and reporting.

Each owner or operator is required to submit a notification of compliance status report, as required by § 63.9(h) of the General Provisions. This final rule requires the owner or operator to include in the notification of compliance status report certifications of compliance with rule requirements.

Semiannual compliance reports, as required by § 63.10(e)(3) of subpart A, are required only for semiannual reporting periods when a deviation from any of the requirements in the rule occurred, or any process changes occurred and compliance certifications were reevaluated.

This final rule requires records to demonstrate compliance with each emission limit and work practice standard. These recordkeeping requirements are specified directly in the General Provisions to 40 CFR part

63, and are identified in Table 10. Owners or operators of sources with units with heat input capacity of less than 10 MMBtu/hr, units combusting natural gas or other clean gas, metal process furnaces, limited use units, and temporary use units must keep records of the dates and the results of each required boiler tune-up.

Records of either continuously monitored parameter data for a control device if a device is used to control the emissions or CEMS data are required.

You are required to keep the following records:

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

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

(3) Each instance in which you did not meet each emission limit and each operating limit (*i.e.,* deviations from this final rule).

(4) Daily hours of operation by each source.

(5) Total fuel use by each affected source electing to comply with an emission limit based on fuel analysis for each 30-day period along with a description of the fuel, the total fuel usage amounts and units of measure, and information on the supplier and original source of the fuel.

(6) Calculations and supporting information of chlorine fuel input, as required in this final rule, for each affected source with an applicable HCl emission limit.

(7) Calculations and supporting information of Hg fuel input, as required in this final rule, for each affected source with an applicable Hg emission limit.

(8) A signed statement, as required in this final rule, indicating that you burned no new fuel type and no new fuel mixture or that the recalculation of chlorine input demonstrated that the new fuel or new mixture still meets chlorine fuel input levels, for each affected source with an applicable HCl emission limit.

(9) A signed statement, as required in this final rule, indicating that you burned no new fuels and no new fuel mixture or that the recalculation of Hg fuel input demonstrated that the new fuel or new fuel mixture still meets the Hg fuel input levels, for each affected source with an applicable Hg emission limit.

(10) 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 this final rule.

(11) A copy of your site-specific monitoring plan developed for this final rule as specified in 63 CFR 63.8(e), if applicable.

We are also requiring that you 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 this subpart, even if you submitted an initial notification for the vacated standards that were promulgated in 2004.

(3) Notification of Intent to conduct performance tests and/or compliance demonstration at least 60 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) Compliance reports semi-annually.

I. Submission of Emissions Test Results to EPA

EPA must have performance test data and other compliance data to conduct effective reviews of CAA Section 112 and 129 standards, as well as for many other purposes including compliance determinations, emissions factor development, and annual emissions rate determinations. In conducting these required reviews, we have found it ineffective and time consuming not only for us but also for regulatory agencies and source owners and operators to locate, collect, and submit emissions test data because of varied locations for data storage and varied data storage methods. One improvement that has occurred in recent years is the availability of stack test reports in electronic format as a replacement for cumbersome paper copies.

In this action, we are taking a step to improve data accessibility. Owners and operators of ICI boilers located at major source facilities will be required to submit to EPA an electronic copy of reports of certain performance tests required under this final rule. Data will be collected through an electronic emissions test report structure called the Electronic Reporting Tool (ERT) that will be used by the staff as part of the emissions testing project. The ERT was developed with input from stack testing companies who generally collect and compile performance test data electronically and offices within State and local agencies which perform field test assessments. The ERT is currently available, and access to direct data submittal to EPA's electronic emissions database (WebFIRE) is scheduled to become available by December 31, 2011.

The requirement to submit source test data electronically to EPA will not require any additional performance testing and will apply to those performance tests conducted using test methods that are supported by ERT. The ERT contains a specific electronic data entry form for most of the commonly used EPA reference methods. The Web site listed below contains a listing of the pollutants and test methods supported by ERT. In addition, when a facility submits performance test data to WebFIRE, there will be no additional requirements for emissions test data compilation. Moreover, we believe industry will benefit from development of improved emissions factors, fewer follow-up information requests, and better regulation development as discussed below. The information to be reported is already required for the existing test methods and is necessary to evaluate the conformance to the test method.

One major advantage of collecting source test data through the ERT is that it provides a standardized method to compile and store much of the documentation required to be reported by this final rule while clearly stating what testing information we require. Another important benefit of submitting these data to EPA at the time the source test is conducted is that it will substantially reduce the effort involved in data collection activities in the future. Specifically, because EPA would already have adequate source category data to conduct residual risk assessments or technology reviews, there would likely be fewer or less substantial data collection requests (e.g., CAA Section 114 letters). This results in a reduced burden on both affected facilities (in terms of reduced manpower to respond to data collection requests) and EPA (in terms of preparing and distributing data collection requests).

State/local/Tribal agencies may also benefit in that their review may be more streamlined and accurate because the States will not have to re-enter the data to assess the calculations and verify the data entry. Finally, another benefit of submitting these data to WebFIRE electronically is that these data will improve greatly the overall quality of the existing and new emissions factors by supplementing the pool of emissions test data upon which the emissions factor is based and by ensuring that data are more representative of current industry operational procedures. A common complaint we hear from industry and regulators is that emissions factors are outdated or not representative of a particular source category. Receiving and incorporating data for most performance tests will ensure that emissions factors, when updated, represent accurately the most current operational practices. In summary, receiving test data already collected for other purposes and using them in the emissions factors development program will save industry, State/local/Tribal agencies, and EPA time and money and work to improve the quality of emissions inventories and related regulatory decisions.

As mentioned earlier, the electronic data base that will be used is EPA's WebFIRE, which is a database accessible through EPA's TTN. The WebFIRE database was constructed to store emissions test and other data for use in developing emissions factors. A description of the WebFIRE data base can be found at *http://cfpub.epa.gov/oarweb/index.cfm?action=fire.main.*

Source owners and operators will be able to transmit data collected via the ERT through EPA's Central Data Exchange (CDX) network for storage in the WebFIRE data base. Although ERT is not the only electronic interface that can be used to submit source test data to the CDX for entry into WebFIRE, it makes submittal of data very straightforward and easy. A description of the ERT can be found at *http://www.epa.gov/ttn/chief/ert/ert_tool.html.*

Source owners and operators must register with the CDX system to obtain a user name and password before being able to submit data to the CDX. The CDX registration page can be found at: *https://cdx.epa.gov/SSL/CDX/regwarning.asp?Referer=registration.* If they have a current CDX account (*e.g.,* they submit reports for EPA's Toxic Release Inventory Program to the CDX), then the existing user name and password can be used to log in to the CDX.

IV. Summary of Significant Changes Since Proposal

A. Applicability

Since proposal, several changes to the applicability of this final rule have been made. First, at proposal, we excluded all units that combust solid waste from the standards, but we have extended the coverage of this final rule to boilers and process heaters that combust solid waste but are exempt, by statute, from section 129 incinerator rules because they are qualifying small power producers or cogeneration units that combust a homogeneous waste stream. This final rule continues to exclude other waste burning units. This is a clarifying change that is consistent with the intent of the proposed rule to establish emissions standards for all boilers and process heaters that are not solid waste incineration units subject to regulation under section 129.

The proposed rule definition of coal was revised to include all types of fossil-based fuels in the coal definition. The final coal definition is: "*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, "Standard Specification for Classification of Coals by Rank" (incorporated by reference, *see* § 63.14(b)), coal refuse, and petroleum coke. For the purposes of this subpart, this definition of "coal" includes 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. Coal derived gases are excluded from this definition." Similarly, for biomass, the definition of biomass fuel was revised to include any potential biomass-based fuels. This is also a clarifying change consistent with the intent of the proposed rule as described above. The final definition is: "Biomass or bio-based solid fuel means any solid biomass-based fuel that is not a solid waste. This may include, but is not limited to, the following materials: Wood residue; wood products (*e.g.,* trees, tree stumps, tree limbs, bark, lumber, sawdust, sanderdust, chips, scraps, slabs, millings, and shavings); animal manure, including litter and other bedding materials; vegetative agricultural and silvicultural materials, such as logging residues (slash), nut and grain hulls and chaff (*e.g.,* almond, walnut, peanut, rice, and wheat), bagasse, orchard prunings, corn stalks, coffee bean hulls and grounds. This definition of biomass fuel is not intended to suggest that these materials are or not solid waste."

The proposed rule included a definition of waste heat boiler that excluded from the definition units with supplemental burners that are designed to supply 50 percent or more of the total rated heat input capacity. The final definition was revised to include all waste heat boilers. The final definition is: "Waste heat boiler means a device that recovers normally unused energy and converts it to usable heat. Waste heat boilers are also referred to as heat recovery steam generators." Similarly, the waste heat process heater definition was revised to read as follows: "Waste heat process heater means an enclosed device that recovers normally unused energy and converts it to usable heat. Waste heat process heaters are also referred to as recuperative process heaters." These changes were made in order to exempt the types of units intended at proposal.

The proposed rule exempted blast furnace gas fuel-fired boiler or process heaters, and defined these units as units combusting 90 percent or more of its total heat input from blast furnace gas. We have changed the requirement to 90 percent or more of its total volume of gas in this final rule. This change was made so that the units that were intended to be exempted from this final rule would be exempted. The wording of the proposed exemption did not exempt units that were intended to be exempted because the heating value of blast furnace gas is not as high as that of natural gas.

The proposed rule exempted units that are an affected source in another MACT standard. We amended this language to include any unit that is part of the affected source subject to another MACT standard. We also exempted any unit that is used as a control device to comply with another MACT standard, provided that at least 50 percent of the heat input is provided by the gas stream that is regulated under another MACT standard. This change was made in order to encourage the recovery of energy from high heating value gases that would otherwise be flared.

B. Subcategories

In the proposed rule, for the fuel-dependent HAP (metals, Hg, acid gases), we identified the following five basic unit types as subcategories: (1) Units designed to burn coal, (2) units designed to burn biomass, (3) units designed to burn liquid fuel, (4) units designed to burn natural gas/refinery gas, and (5) units designed to burn other process gases. In this final rule, for fuel-dependent HAP, we combined the subcategories for units designed to combust coal and biomass into a subcategory for units designed to burn solid fuels. We changed the subcategory for units designed to burn natural gas/refinery gas to a subcategory for units that burn natural gas, refinery gas, and other clean gas. We also added subcategories for non-continental liquid units and limited-use units.

As described in the preamble to the proposed rule, within the basic unit types there are different designs and combustion systems that, while having a minor effect on fuel-dependent HAP emissions, have a much larger effect on pollutants whose emissions depend on the combustion conditions in a boiler or process heater. In the case of boilers and process heaters, the combustion-related pollutants are the organic HAP. In the proposed rule, we identified the following 11 subcategories for organic HAP: (1) Pulverized coal units; (2) stokers designed to burn coal; (3) fluidized bed units designed to burn coal; (4) stokers designed to burn biomass; (5) fluidized bed units designed to burn biomass; (6) suspension burners/dutch ovens designed to burn biomass; (7) fuel cells designed to burn biomass; (8) units designed to burn liquid fuel; (9) units designed to burn natural gas/refinery gas; (10) units designed to burn other gases; and (11) metal process furnaces. In this final rule, we added subcategories for biomass suspension/grate units, non-continental liquid units, and limited-use units.

C. Emission Limits

The proposed rule included numerical emission limits for PM, Hg, HCl, CO, and dioxin/furan, and limits for those same pollutants are included in this final rule. Unlike the proposed rule, we included a compliance alternative in the final rule to allow owners and operators of existing affected sources to demonstrate compliance on an output-basis instead of on a heat input basis. Compliance with the alternate output-based emission limits would require measurement of boiler operating parameters associated with the mass rate of emissions and energy outputs. If you elect to comply with the alternate output-based emission limits, you must use equations provided in the final rule to demonstrate that emissions from the applicable units do not exceed the output-based emission limits specified in the final rule. If you use this compliance alternative using the emission credit approach, you must also establish a benchmark, calculate and document the emission credits generated from energy conservation measures implemented, and develop and submit the implementation plan no later than 180 days before the date that the facility intends to demonstrate compliance.

D. Work Practices

This final rule includes work practice standards for most of the same units for which we proposed work practice standards, including new and existing units in the Gas 1 subcategory, existing units with heat input capacity less than 10 MMBtu/hr, and new and existing metal process furnaces. In addition to those subcategories for which we proposed work practices, this final rule includes work practices for all units during periods of startup and shutdown, new units with heat input capacity less than 10 MMBtu/hr, limited use units, and units combusting other clean gases. Other clean gases are gases, other than natural gas and refinery gas (as defined in this final rule), that meet contaminant level specifications that are provided in the final rule.

E. Energy Assessment Requirements

In this final rule, we have expanded the definition of energy assessment with respect to the requirements of Table 3 of this final rule, by providing a duration for performing the energy assessment and defining the evaluation requirements for each boiler system and energy use system. These requirements are based on the total annual heat input to the affected boilers and process heaters.

This final rule requires an energy assessment for facilities with affected boilers and process heaters using less than 0.3 trillion Btu per year (TBtu/y) heat input to be one day in length maximum. The boiler system and energy use system accounting for at least 50 percent of the energy output from these units must be evaluated to identify energy savings opportunities within the limit of performing a one day energy assessment. An energy assessment for a facility with affected boilers and process heaters using 0.3 to 1 TBtu/year must be three days in length maximum. From these boilers, the boiler system and any energy use system accounting for at least 33 percent of the energy output will be evaluated, within the limit of performing a three day energy assessment. For facilities with affected boilers and process heaters using greater than 1 TBtu/year heat input, the energy assessment must address the boiler system and any energy use system accounting for at least 20 percent of the energy output to identify energy savings opportunities.

The expanded definition for energy assessment clarifies the duration and requirements for each energy assessment for various units based on energy use. We have also added a definition for steam and process heating systems to clarify the components for each boiler system which must be considered during the energy assessment, including elements such as combustion management, thermal energy recovery, energy resource selection, and the steam end-use management of each affected boiler.

Lastly, we have clarified the requirement in Table 3 to evaluate facility energy management practices as part of the energy assessment and a definition of an energy management program was added. The use of the ENERGY STAR Facility Energy Assessment Matrix as part of this review is recommended, but it was removed as a requirement in Table 3. The definition of an energy management program added to the rule is consistent with the ENERGY STAR Guidelines for Energy Management that can be referenced for further guidance. ENERGY STAR provides a variety of tools and resources that support energy management programs. For more information, visit *http://www.energystar.gov.*

F. Requirements During Startup, Shutdown, and Malfunction

For startup, shutdown, and malfunction (SSM), the requirements have changed since proposal. For periods of startup and shutdown, EPA is finalizing work practice standards, which require following manufacturers specifications for minimizing periods of startup and shutdown, in lieu of numeric emission limits. For malfunctions, EPA added affirmative defense language to this final rule for exceedances of the numerical emission limits that are caused by malfunctions.

G. Testing and Initial Compliance

The first significant change to the testing and initial compliance requirements is that units greater than 100 MMBtu/hr must comply with the CO limits using a stack test rather than CO CEMS. EPA also added optional output-based limits that promote energy efficient boiler operation. Another significant change is that for units combusting gaseous fuels other than natural gas or refinery gas, in order to qualify for the Gas 1 subcategory work practice standard, the gases that will be combusted must be certified to meet the contaminant levels specified for Hg and hydrogen sulfide (H_2S) in this final rule. Finally, EPA has changed the dioxin/furan testing requirement to a one-time compliance demonstration due to the low dioxin/furan emissions demonstrated by the vast majority of sources that have tested for dioxin/furan.

H. Continuous Compliance

The only significant change to the continuous compliance requirements is for monitoring of CO. Rather than using CO CEMS, as proposed, units will be required to continuously monitor and record the oxygen level in their flue gas during the initial compliance test and establish an operating limit that requires that the unit operate at an oxygen percentage of at least 90 percent of the operating limit on a 12-hour block average basis. Units will be required to continuously monitor oxygen to ensure continuous compliance.

I. Notification, Recordkeeping, and Reporting

In this final action, we are requiring that owners or operators of boilers that choose to commence or recommence combustion of solid waste must provide 30 days notice of the date upon which the source will commence or recommence combustion of solid waste. The notification must identify the name of the owner or operator of the affected source, the location of the source, the boiler(s) or process heater(s) that will commence burning solid waste, and the date of the notice; the currently applicable subcategory under this subpart; the date on which the unit became subject to the currently applicable emission limits; and the date upon which the unit will commence or recommence combusting solid waste.

For each limited-use unit, owners or operators must monitor and record the operating hours on a monthly basis for the unit. This will ensure that units qualify for the limited-use subcategory.

We also added a requirement that sources keep records of operating load in order to demonstrate continuous compliance with the operating load operating limit.

When malfunctions occur, owners or operators must keep records of the occurrence and duration of each malfunction of the boiler or process heater, or of the associated air pollution control and monitoring equipment, as well as records of actions taken during periods of malfunction to minimize emissions, including corrective actions to restore the malfunctioning boiler or process heater, air pollution control, or monitoring equipment to its normal or usual manner of operation.

Finally, for facilities that elect to use emission credits from energy conservation measures to demonstrate compliance, owners or operators must keep a copy of the Implementation Plan required in this rule and copies of all data and calculations used to establish credits.

J. Technical/Editorial Corrections

In this final action, we are making a number of technical corrections and clarifications to subpart DDDDD. These changes improve the clarity and procedures for implementing the emission limitations to affected sources. We are also clarifying several definitions to help affected sources determine their applicability. We have modified some of the regulatory language that we proposed based on public comments.

In several places throughout the subpart, including the associated tables, we have corrected the cross-references to other sections and paragraphs of the subpart.

We revised 40 CFR 63.7485 to clarify that for the purposes of subpart DDDDD, a major source of HAP is as defined in 40 CFR 63.2, except that for oil and gas facilities a major source of HAP is as defined in 40 CFR 63.761 (40 CFR part 63, subpart HH, National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities). This change was made because facilities subject to subpart HH contain units that will be subject to subject DDDDD.

The word “specifically” was removed from § 63.7491(i) in order to clarify the exclusion for boilers and process heaters regulated by other HAP regulations.

We revised 40 CFR 63.7505(c) to clarify that performance testing is needed only if a boiler or process heater is subject to an applicable emission limit listed in Table 2.

We made several changes to the initial compliance demonstration requirements. We revised 40 CFR 63.7510(a) to clarify that sources using a second fuel only for start up, shut down, and/or transient flame stability are still considered to be sources using a single fuel. We revised 40 CFR 63.7510(c) to clarify that boilers and process heaters with a heat input capacity below 10 MMBtu per hour are not required to conduct a performance test for CO because they are not subject to a numerical emission limit for CO. In 40 CFR 63.7510(d), we clarified that boilers and process heaters that use a CEMS for PM are exempt from the performance testing and operating limit requirements specified in 40 CFR 63.7510(a) because the CEMS demonstrates continuous compliance. We revised 40 CFR 63.7510(c) and (d) to clarify that compliance for those provisions does not apply to units burning natural gas or refinery gas.

We changed the performance testing requirements in 40 CFR 63.7515(b), (c), and (d) to state that performance testing for a given pollutant may be performed every 3 years, instead of annually, if measured emissions during 2 consecutive annual performance tests are less than 75 percent of the applicable emission limit.

In 40 CFR 63.7515(e), we clarified that boilers and process heaters with a heat input capacity below 10 MMBtu per hour are required to conduct tune-ups biennially, while larger natural gas and other Gas 1 units are required to conduct annual tune-ups.

We revised 40 CFR 63.7515(f) to clarify that monthly fuel analyses are required only for fuel types for which emission limits apply.

We made several changes to 40 CFR 63.7520 to clarify the performance testing requirements. We revised paragraph (c) to clarify that performance tests must be conducted at representative operating load conditions, instead of at the maximum normal operating load. Language was also added to this section and to Table 4 to subpart DDDDD to establish an operating limit for the boiler or process heater and clarified that the operating load must not exceed 110 percent of the load used during the performance test. We revised paragraph (d) to clarify that compliance with operating limits using a continuous parameter monitoring systems are based on the 4-hour block averages of the data collected by the continuous parameter monitoring systems.

In 40 CFR 63.7522, we made several changes to the provisions for using emissions averaging. In paragraph (a), we clarified that average emissions must be “* * * not more than 90 percent of the applicable emission limit.” We also added a sentence to clarify that new boilers and process heaters may not be included in an emissions average used to demonstrate compliance according to that section. Equations 2 and 3 were revised to correct the discount factor from 0.9 to 1.1 because the actual emissions are multiplied by the discount factor. We also revised paragraph (c) to clarify that the deadline to establish emission caps to demonstrate compliance with the emission averaging option is 60 days after the publication of the final rule as referenced in paragraph (g)(2)(i), and revised paragraph (g) to clarify that facilities are required to submit an implementation plan as referenced in § 63.7522(g)(1).

We made several clarifying changes to the monitoring requirements in 40 CFR 63.7525. We revised paragraph (a) to clarify that only boilers or process heaters subject to a CO limit are required to install a continuous oxygen monitoring system. We adopted language from § 63.7525(d)(2) to § 63.7525(a)(6) to clarify what constitutes a deviation. In 40 CFR 63.7525(c)(7), we clarified that owners/operators are required to determine 6-minute and daily block averages excluding data from periods in which the continuous opacity monitoring system is out of control.

The initial compliance provisions in 40 CFR 63.7530(b) were revised to clarify that facilities are exempted from the initial compliance requirements of conducting a fuel analysis if only one fuel type is used. We revised 40 CFR 63.7530(d) to clarify that units less than 10 MMBtu per hour are required to submit a signed statement with the Notification of Compliance Status report that indicates a tune-up has been conducted.

We revised 40 CFR 63.7540(a)(9)(i) to remove the reference to Procedure 2 in Appendix F to 40 CFR part 60; Procedure 2 specifies the ongoing QA/QC requirements for PM CEMS after certification and is correctly referenced in paragraph (a)(9)(iii) of that section.

We revised the notification requirements in 40 CFR 63.7545 to clarify that notifications should be submitted to the delegated authority, and to clarify that the Notification of Intent to conduct a performance test must be submitted 60 days before the test is scheduled to begin.

The reporting requirements originally in 40 CFR 63.7550(g) and (g)(1) through (g)(3) are more correctly considered notification requirements, so they were moved to § 63.7545(e)(8).

In response to comments asking for clarification, we have added definitions to 40 CFR 63.7575 for "Calendar year," "Operating day," "Refinery gas," and "Valid hourly average." We have also revised several definitions in that section based on public comments. For example, we revised the definition of "boiler" to describe what is meant by the term "controlled flame combustion" as used in that definition; revised "metal processing furnace" to include homogenizing furnaces; revised the definitions of "dry scrubber," "electrostatic precipitator," and "fabric filter," to indicate that these are all considered dry control systems. The definition of "wet scrubber" was revised to clarify that, "A wet scrubber creates an aqueous stream or slurry as a byproduct of the emissions control process."

The definition of "Tune-up" was removed from 40 CFR 63.7575 because all of the requirements for a tune-up are provided in the rule language at 40 CFR 63.7540(a)(10), making the definition unnecessary.

Several of the definitions in 40 CFR 64.7575 were revised to clarify the types of equipment to which different standards apply. For example, the definition of "Temporary boiler" was revised to include additional criteria that could be used to identify temporary boilers from permanently installed units. The definition of "Unit designed to burn oil subcategory" was revised to exclude periods of gas curtailment and gas supply emergency from the 48-hour limit on liquid fuel combustion. Likewise, the definition of "Period of natural gas curtailment" was revised to clarify that contractual agreements for curtailed gas usage or fluctuations in price do not constitute periods of gas curtailment under the scope of this regulation. The definition of "Waste heat boiler" was revised to remove the criteria that 50 percent of total rated heat input capacity had to be from waste gases. We also revised the definition of "Natural gas" to include gas derived from naturally occurring mixtures found in geological formations as long as the principal constituent is methane, consistent with the definition provided in 40 CFR part 60 subpart Db. A definition of propane, was also incorporated into the definition of natural gas.

Several changes were made to the tables to subpart DDDDD as a result of the public comments on the proposed rule.

In Tables 1 and 2, the references to "Other gases" were revised to "Gas 2" to clarify that units burning natural gas, refinery gas, or other clean gases are not subject to emission limitations. The emission limits in these two tables were also revised to include averaging times for those pollutants for which measurements are taken with a continuous emission monitor.

In Table 3, the references to "§ 63.11202 and § 63.11203" in the table heading were revised to correctly reference 40 CFR 63.7540. The text in the first and second column of Table 3 was revised to clarify that the requirements apply to both boilers and process heaters. A new row was added to clarify that work practice standards apply to new boilers or process heaters with a rated heat input capacity less than 10 MMBtu per hour. Language was also added to clarify that the energy assessment is a one-time requirement for existing boilers and process heaters. Additionally, new language was added clarifying the evaluation of the facility's energy management program as part of the energy assessment.

In Table 4, operating limits for pH added to Item 1 for wet scrubbers, as specified in 40 CFR 63.7530(b)(3)(i). Item 5 revised to clarify that "Any other control type" only means add-on air-pollution control devices. The operating limits were also revised to clarify which units and control combinations were required to install and operate a bag leak detection system, to install and operate a continuous opacity monitor, or to monitor voltage and amperage of an ESP. These changes removed the appearance that some units would need to do more than one type of monitoring for control of PM. This table was also revised to include a row for an operating limit for unit operating load for those units that demonstrate compliance using a performance test.

Table 5 was revised to include EPA Method 23 as the accepted method for measuring dioxin/furan. A new Table 11 was also added to document the toxic equivalency factors that should be used to demonstrate compliance with the toxic equivalents (TEQ) emission limits.

Table 7 was revised to include dry scrubbers and activated carbon injection used to comply with Hg or dioxin/furan emission limitations, and to include procedures for determining the corresponding operating limit requirements. Procedures were also added for determining the operating limit for unit operating load for units that demonstrate compliance through performance testing. Finally, this table was revised to clarify how the operating limits should be determined for wet scrubbers and for ESPs operated with wet scrubbers.

Table 8 was revised to correct certain cross-references to 40 CFR 63.7530, and to include procedures for demonstrating continuous compliance with the operating limit for unit operating load.

Table 9 was revised to correct cross-references to 40 CFR 63.7550(c) and Table 3 for work practice standards. Language in Item 1.c. revised to more clearly match the language in 40 CFR 63.7530(d) and (e), and Item 1.c. was split into Items 1.c. and 1.d.

K. Other

The definition of a boiler and the definition of a process heater have been revised to include units that combust solid waste but are exempt, by statute, from section 129. This change was necessary in order to provide coverage of units that would otherwise be exempt from any requirements. The revised definitions read as follows:

Boiler means an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled. A device combusting solid waste, as defined in 40 CFR 241.3, is not a boiler unless the device is exempt from the definition of a solid waste incineration unit as provided in CAA section 129(g)(1). Waste heat boilers are excluded from this definition.

Process heater means an enclosed device using controlled flame, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not directly come into contact with process materials. For purposes of this subpart, a device combusting solid waste, as defined in 40 CFR 241.3, is not a process heater unless the device is exempt from the definition of a solid waste incineration unit as provided in CAA section 129(g)(1). Process heaters do not include units used for comfort heat or space heat, food preparation for on-site consumption, or autoclaves.

As a result of new data received for the floor calculations, revised treatment of low reported CO data to consider measurement error, and a new subcategorization scheme, some of the final CO limits for new sources in Table 1 of this final rule are more stringent than proposed, as are some of the other limits for certain subcategories (e.g., PM and Hg for liquid fuel units, and PM and HCl for solid fuel units when compared to the proposed new source limits for the proposed biomass/bio-based fuel subcategory). Where a final limit is more stringent than proposed, 40 CFR 63.6 of subpart A (General Provisions), requires that new sources that commenced construction between proposal and promulgation be allowed to comply with the proposed limits for 3 years (i.e., up to the existing source compliance date) and then comply with the final limits for new sources listed in Table 1 of this final rule. In this final rule we have added a new Table 12 to outline the emission limits applicable to sources that commenced construction between proposal and promulgation and updated the rule language to provide instructions on which limits apply to them for the 3 year period after this final rule is published. These sources have the option to comply with Table 1 (final) limits from the start, if they choose.

V. Major Source Public Comments and Responses

A. MACT Floor Analysis

1. Pollutant-by-Pollutant Approach

Comment: Many commenters raised concerns about the way EPA determined the MACT floors using a pollutant-by-pollutant approach. Commenters contended that such a methodology produced limits that are not achievable in combination, and as such, the limits do not comport with the intent of the statute or the recent court decision (*NRDC* v. *EPA*, 2007). Commenters argue that while the Court's 2007 decision in *NRDC* v. *EPA* vacating the first ICI boiler and process heater MACT standard directed EPA to consider individual HAPs, it did not direct EPA to establish a separate floor for each HAP. Commenters further added that the Clean Air Act (CAA) directs EPA to set standards based on the overall performance of "sources" and sections 112(d)(1), (2), and (3) specify that emissions standards be established on the "in practice" performance of a "source" in the category or subcategory. If Congress had intended for EPA to establish MACT floor levels considering the achievable emission limits of individual HAPs, it could have worded 112(d)(3) to refer to the best-performing sources "for each pollutant." Many commenters added that EPA's discretion in setting standards is limited to distinguishing among classes, types, and sizes of sources. However, Congress limited EPA's authority to parse units and sources with similar design and types but it does not allow EPA to "distinguish" units and sources by individual pollutant as proposed in this rule [*Sierra Club* v. *EPA,* 551 F.3d 1019, 1028 (D.C. Cir. 2008)]. By calculating each MACT floor independently of the other pollutants, the combination of HAP limits results in a set of standards that only a hypothetical "best performing" unit could achieve.

Many commenters who criticized the pollutant-by-pollutant approach also filed comments on other rules such as the recent Portland Cement NESHAP and the NSPS and Emission Guidelines for Hospital/Medical Infectious Waste Incinerators (HMIWI). Some commenters expressed concern that EPA used a similar pollutant-by-pollutant approach in the HMIWI rulemaking and that rulemaking is being challenged before the D.C. Circuit. Commenters also submitted a variety of suggestions on calculating a multi-pollutant approach. Some commenters suggested that human health be considered by weighting pollutants according to relative-toxicity and then ranking the units in each subcategory according to their weighted emission totals in order to identify the best performing 12 percent of sources for all pollutants.

Response: We disagree with the commenters who believe MACT floors cannot be set on a pollutant-by-pollutant basis. Contrary to the commenters' suggestion, section 112(d)(3) does not mandate a total facility approach. A reasonable interpretation of section 112(d)(3) is that MACT floors may be established on a HAP-by-HAP basis, so that there can be different pools of best performers for each HAP. Indeed, as illustrated below, the total facility approach not only is not compelled by the statutory language but can lead to results so arbitrary that the approach may simply not be legally permissible.

Section 112(d)(3) is ambiguous as to whether the MACT floor is to be based on the performance of an entire source or on the performance achieved in controlling particular HAP. Congress specified in section 112(d)(3) the minimum level of emission reduction that could satisfy the requirement to adopt MACT. For new sources, this floor level is to be "the emission control that is achieved in practice by the best controlled similar source." For existing sources, the floor level is to be "the average emission limitation achieved by the best performing 12 percent of the existing sources" for categories and subcategories with 30 or more sources, or "the average emission limitation achieved by the best performing 5 sources" for categories and subcategories with fewer than 30 sources. Commenters point to the statute's reference to the best performing "sources," and claim that Congress would have specifically referred to the best performing sources "for each pollutant" if it intended for EPA to establish MACT floors separately for each HAP. EPA disagrees. The language of the Act does not address whether floor levels can be established HAP-by-HAP or by any other means. The reference to "sources" does not lead to the assumption the commenters make that the best performing sources can only be the best-performing sources for the entire suite of regulated HAP. Instead, the language can be reasonably interpreted as referring to the source as a whole or to performance as to a particular HAP. Similarly, the reference in the new source MACT floor provision to "emission control achieved by the best controlled similar source" can mean emission control as to a particular HAP or emission control achieved by a source as a whole.

Industry commenters also stressed that section 112(d) requires that floors be based on actual performance from real facilities, pointing to such language as "existing source", "best performing", and "achieved in practice". EPA agrees that this language refers to sources' actual operation, but again the language says nothing about whether it is referring to performance as to individual HAP or to single facility's performance for all HAP. Industry commenters also said that Congress could have mandated a HAP-by-HAP result by using the phrase "for each HAP" at appropriate points in section 112(d). The fact that Congress did not do so does not compel any inference that Congress was *sub-silentio* mandating a different result when it left the provision ambiguous on this issue. The argument that MACT floors set HAP-by-HAP are based on the performance of a hypothetical facility, so that the limitations are not based on those achieved in practice, just re-begs the question of whether section 112(d)(3) refers to whole facilities or individual HAP. All of the limitations in the floors in this rule of course reflect sources' actual performance and were achieved in practice. Finally, there are a number of existing units that *meet all* of the final existing source emission limits.

Commenters also point to EPA's subcategorization authority, and claim that because Congress authorized EPA to distinguish among classes, types, and sizes of units, EPA cannot distinguish units by individual pollutant, as they allege EPA did in the proposed rule. However, that statutory language addresses EPA's authority to subcategorize sources within a source category prior to setting standards, which EPA has done for boilers and process heaters. EPA is not distinguishing within each subcategory based on HAP emitted. Rather, it is establishing emissions standards based on the emissions limits achieved by units in each subcategory. Therefore, EPA's subcategorization authority is irrelevant to the question of how EPA establishes MACT floor standards once it has made the decision to distinguish among sources and create subcategories.

EPA's long-standing interpretation of the Act is that the existing and new source MACT floors are to be established on a HAP-by-HAP basis. One reason for this interpretation is that a whole plant approach could yield least common denominator floors—that is floors reflecting mediocre or no control, rather than performance which is the average of what best performers have achieved. *See* 61 FR at 173687 (April 19, 1996); 62 FR at 48363–64 (September 15, 1997) (same approach adopted under the very similar language of section 129(a)(2)). Such an approach would allow the performance of sources that are outside of the best-performing 12 percent for certain pollutants to be included in the floor calculations for those same pollutants, and it is even conceivable that the worst performing source for a pollutant could be considered a best performer overall, a result Congress could not have intended. Inclusion of units that are outside of the best performing 12 percent for particular pollutants would lead to emission limits that do not meet the requirements of the statute.

For example, if the best performing 12 percent of facilities for HAP metals were also the worst performing units for organics, the floor for organics or metals would end up not reflecting best performance. In such a situation, EPA would have to make some type of value judgment as to which pollutant reductions are most critical to decide which sources are best controlled.[3] Such value judgments are antithetical to the direction of the statute at the MACT floor-setting stage. Commenters suggested that a multi-pollutant approach could be implemented by weighting pollutants according to relative toxicity and calculating weighted emissions totals to use as a basis for identifying and ranking best performers. This suggested approach would require EPA to essentially prioritize the regulated HAP based on relative risk to human health of each pollutant, where risk is a criterion that has no place in the establishment of MACT floors, which are required by statute to be based on technology.

The central purpose of the amended air toxic provisions was to apply strict technology-based emission controls on HAPs. *See*, *e.g.*, H. Rep. No. 952, 101st Cong. 2d sess. 338. The floor's specific purpose was to assure that consideration of economic and other impacts not be used to "gut the standards. While costs are by no means irrelevant, they should by no means be the determining factors. There needs to be a minimum degree of control in relation to the control technologies that have already been attained by the best existing sources." A Legislative History of the Clean Air Act *Vol. II* at 2897 (statement of Rep. Collins). An interpretation that the floor level of control must be limited by the performance of devices that only control some of these pollutants effectively "guts the standards" by including worse performers in the averaging process, whereas EPA's interpretation promotes the evident Congressional objective of having the floor reflect the average performance of best performing sources. Since Congress has not spoken to the precise question at issue, and the Agency's interpretation effectuates statutory goals and policies in a reasonable manner, its interpretation must be upheld. *See Chevron* v. *NRDC,* 467 U.S. 837 (1984).[4]

It is true that legislative history can sometimes be so clear as to give clear meaning to what is otherwise ambiguous statutory text. As just explained, EPA's HAP-by-HAP approach fulfills the evident statutory purpose and is supported by the most pertinent legislative history. A few industry commenters nonetheless indicated that a HAP-by-HAP approach is inconsistent with legislative history to section 112(d), citing to page 169 of the Senate Report. Since this Report was to a version of the bill which did not include a floor provision at all (much less the language at issue here), it is of no relevance. *National Lime II,* 233 F. 3d at 638.

Industry commenters also noted that EPA retains the duty to investigate and, if justifiable, to adopt beyond the floor standards, so that potential least common denominator floors resulting from the whole facility approach would not have to "gut the standards." That EPA may adopt more stringent standards based on what is "achievable" after considering costs and other factors is irrelevant to how EPA is required to set MACT floors. MACT floors must be based on the emission limitation achieved by the best performing 12 percent of existing sources, and, for new sources, on the level achieved by the best controlled similar source, and EPA must make this determination without consideration of cost. At best, standards reflecting a beyond-the-floor level of performance will have to be cost-justified; at worst, standards will remain at levels reflecting mediocre performance. Under either scenario, Congress' purpose in requiring floors is compromised.

EPA notes, however, that if optimized performance for different HAPs is not technologically possible due to mutually inconsistent control technologies (for example, metals performance decreases if organics reduction is optimized), then this would have to be taken into account by EPA in establishing a floor (or floors). The Senate Report indicates that if certain types of otherwise needed controls are mutually exclusive, EPA is to optimize the part of the standard providing the most environmental protection. S. Rep. No. 228, 101st Cong. 1st sess. 168 (although, as noted, the bill accompanying this Report contained no floor provisions). It should be

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[3] *See* Petitioners Brief in *Medical Waste Institute et al.* v. *EPA*, No. 09–1297 (D.C. Cir.) pointing out, in this context, that "the best performers for some pollutants are the worst performers for others" (p. 34) and "[s]ome of the best performer for certain pollutants are among the worst performers for others."

[4] Since industry commenters argued that the statute can only be read to allow floors to be determined on a single source basis, commenters offered no view of why their reading could be viewed as reasonable in light of the statute's goals and objectives. It is not evident how any statutory goal is promoted by an interpretation that allows floors to be determined in a manner likely to result in floors reflecting emissions from worst or mediocre performers.

emphasized, however, that "the fact that no plant has been shown to be able to meet all of the limitations does not demonstrate that all the limitations are not achievable." *Chemical Manufacturers Association* v. *EPA,* 885 F. 2d at 264 (upholding technology-based standards based on best performance for each pollutant by different plants, where at least one plant met each of the limitations but no single plant met all of them).

All available data for boilers and process heaters indicate that there is no technical problem achieving the floor levels contained in this final rule for each HAP simultaneously, using the MACT floor technology. Data demonstrating a technical conflict in meeting all of the limits have not been provided, and, in addition, there are a number of units that meet all of the final existing source emission limits.

2. Minimum Number of Units To Set New Source Floors

Comment: Many commenters indicated that section 112 requires that data from a minimum of 5 units is required to set MACT floors for existing sources. Commenters noted that EPA's use of less than 5 units for subcategories with greater than 30 units is a legalistic reading of section 112 that could result in such absurd results as using 5 units to set MACT floors for a subcategory with 29 units and data for only 10 units, but using a single unit to set MACT floors for a subcategory with 31 units and data for only 10 units.

Response: EPA does not agree that section 112(d)(3) mandates a minimum of 5 sources in all instances, notwithstanding the incongruity of having less data to establish floors for larger source categories than is mandated for smaller ones. The literal language of the provision appears to compel this result. Section 112(d)(3) states that for categories and subcategories with at least 30 sources, the MACT floor for existing sources shall be no less stringent than the average emission limitation achieved by the best-performing twelve percent of the sources for which the Administrator has emissions information. The plain language of this provision requires that, for subcategories with at least 30 sources but where the Administrator only has emissions information on a small number of units, the floor can be no less stringent than the average emission limitation achieved by the best-performing twelve percent of those sources.

3. Treatment of Detection Levels

Comment: When setting the MACT floors, non-detect values are present in many of the datasets from best performing units. Commenters provided input on how these non-detect values should be treated in the MACT floor analysis. Some commenters agreed that it is appropriate to keep the detection levels as reported; while certain commenters suggested that the detection levels should be replaced using a value of half the method detection limit (MDL). Many other commenters stated that data that are below the detection limit should not be used in setting the floors, and these data should be replaced with a higher value including either the MDL, limit of quantitation (LOQ), practical quantitation limit (PQL), or reporting limit (RL) for the purposes of the MACT floor calculations. Other commenters stated all non-detect values should be excluded from the floor analysis, or all values should be treated as 0. Some commenters stated it is necessary to keep the data as reported because changing values would lead to an upward bias. Additional commenters agreed with this basic premise, but suggested that replacing non-detect data with a value of half the MDL is appropriate while still minimizing the bias. They noted that treating measurements below the MDL as occurring at the MDL is statistically incorrect and violates the statute's "shall not be less stringent than" requirement for MACT floors. One commenter also provided a reference for a statistical method based on a log-normal distribution of the data which estimated the "maximum likelihood" of data values; this result is slightly higher than half the MDL. Some commenters stated that it is necessary to substitute the MDL value when performing the MACT floor calculations. With MDL defined as the lowest concentration that can be distinguished from the blank at a defined level of statistical significance, this is an appropriate value. If MDL values are not reported, one commenter suggested an approach for estimating an MDL equivalent value, but recognized that the background laboratory and test report files may not be available to EPA in order to derive these estimates. Most commenters representing industry and industry trade groups argued that either LOQ or PQL values should replace non-detects. The LOQ is defined as the smallest concentration of the analyte which can be measured. These commenters contended that the LOQ leads to a quantifiable amount of the substance with an acceptable level of uncertainty. A few commenters provided calculations showing some of the proposed MACT floors were below the LOQ. Additionally, some of these commenters stated that using LOQ or PQL values also incorporates additional sources of random and inherent sampling error throughout the testing process, which is necessary. These errors occur during sample collection, sample recovery, and sample analysis; MDL values only account for method specific (e.g., instrument) errors. These commenters contended that the three times the MDL approach discussed in the proposal accounts for some measurement errors but does not account for these unavoidable sampling errors. The commenters also noted that an LOQ is calculated as 3.18 times the MDL, and PQL is calculated as 5–10 times the MDL. Many of the commenters in support of using either an LOQ or PQL value ultimately believed a work practice is more appropriate where a MACT floor limit is below either of these two values. They cited 112(h)(1) which allows work practices under 112(h)(2) if "the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations". These commenters stated that the inability of sources to accurately measure a pollutant at the level of the MACT floor qualifies as such a technological limitation that warrants a work practice standard.

Where the proposed MACT floor is below the LOQ or PQL then that source category has a technological measurement limitation. A few commenters suggested RL values should be used when developing the floor limits. They stated that the RL is the lowest level at which the entire analytical system gives reliable signals and includes an acceptable calibration point. They added that use of an acceptable calibration point is critical in showing that numbers are real versus multiplying the MDL by various factors.

Several commenters stated that all non-detect values should be excluded from MACT floor calculations. They believed that excluding all non-detect values would eliminate any potential errors or accuracy issues related to testing for compliance. Due to inconsistencies of the MDL value reported for non-detect data, one commenter suggested treating all such values as zero. This would provide a consistent approach for setting the floor as well as determining compliance. Issues discussed by a multitude of commenters were that a wide range of detection limit values were reported and that data from Phase I and Phase II information collection requests (ICR) are inconsistent. For all non-detect data, facilities participating in the Phase II ICR were instructed to report a detection limit, but this resulted in a variety of interpretations by the laboratories who reported data. As such, commenters provided examples where detected values were lower than non-detect values, and in some cases measured values were reported lower than typical method detection limits. Many of the commenters stated it is critical that EPA conduct a thorough quality review of the data to determine if non-detect values have been appropriately flagged and to normalize the data on a consistent basis. One commenter presented an example dataset and the potential implications of the treatment of non-detect data for Hg emissions in the biomass subcategory. This commenter noted that a number of the units with Phase I tests would no longer be considered top performers if their data were made consistent with the Phase II criteria. Several commenters provided remarks for EPA's proposed method of three times the MDL as an option for setting limits. A few commenters in support noted that this approach provided a reasonable method to account for data variability as it took into account more than just analytical instrument precision. Many other commenters argued that this method results in limits which are too low, namely that it is still lower than the LOQ value which they are in favor of as a substitute for any reported non-detect data. On the contrary, some other commenters disagreed with this method and claimed that it would lead to results which introduce a high bias in the floor setting process. A few contended that multiplying by 3 would introduce a 300 percent error into the floor, resulting in a floor that is less stringent than required by the Act. Others suggested that the MDL values are antiquated and already too high and thus it is not appropriate to multiply them by three. Also, a few commenters suggested multiplying the MDL by three would not reflect the actual lower emissions achieved by any source and as such is unlawful under section 112(d).

Response: After consideration of the various comments related to treatment of detection limits in the development of MACT floors, EPA's approach for this final rule is as follows. While commenters suggested using values less than the MDL, such values have not been demonstrated to have been met during the corresponding test run. Therefore, EPA concluded that it is not appropriate, for development of MACT floors, to use any value less than the MDL. EPA also disagrees with comments that emission levels at or near the MDLs are appropriate levels to use for standard setting without consideration of measurement imprecision, because the actual performance of sources may differ significantly from the measured values or the MDL. Accordingly, for the boiler and process heater source category, which includes many sources with emission levels at or near the MDL for the various pollutants, EPA concluded that measurement imprecision was a significant factor that should be included in the development of emission limits. To determine an appropriate methodology, EPA examined the contribution of test method measurement imprecision to the variability of a set of emissions data. One element of variability is associated with method detection capabilities and a second is a function of the measurement value. Measurement imprecision is proportionally highest for values measured below or near a method's detection level and proportionally decreasing for values measured above the method detection level.

The probability procedures applied in calculating the floor or an emissions limit inherently and reasonably account for emissions data variability including measurement imprecision when the database represents multiple tests from multiple emissions units for which all of the data are measured significantly above the method detection level. That is less true when the database includes emissions occurring below method detection capabilities and are reported as the method detection level values.

EPA's guidance to respondents for reporting pollutant emissions used to support the data collection specified the criteria for determining test-specific method detection levels. Those criteria insure that there is only about a 1 percent probability of an error in deciding that the pollutant measured at the method detection level is present when in fact it was absent. Such a probability is also called a false positive or the alpha, Type I, error. Because of sample and emissions matrix effects, laboratory techniques, sample size, and other factors, method detection levels normally vary from test to test for any specific test method and pollutant measurement. The expected measurement imprecision for an emissions value occurring at or near the method detection level is about 40 to 50 percent. Pollutant measurement imprecision decreases to a consistent relative 10 to 15 percent for values measured at a level about three times the method detection level.[5]

Also in accordance with our guidance, source owners identified emissions data which were measured below the method detection level and reported those values as equal to the method detection level as determined for that test. An effect of reporting data in this manner is that the resulting database is truncated at the lower end of the measurement range (i.e., no values reported below the test-specific method detection level). A floor or emissions limit based on a truncated database or otherwise including values measured near the method detection level may not adequately account for measurement imprecision contribution to the data variability. That is, an emission limit set based on the use of the MDL to represent data below the MDL may be significantly different than the actual levels achieved by the best performing units due to the imprecision of the measurements. This fact, combined with the low levels of emissions measured from many of the best performing units, led EPA to develop a procedure to account for the contribution of measurement imprecision to data variability.

We applied the following procedures to account for the effect of measurement imprecision associated with a database that includes method detection level data. The first step was to define a method detection level that is representative of the data used in establishing the floor or emissions limit and that also minimizes the influence of an outlier test-specific method detection level value. We reviewed each pollutant-specific data set to identify the highest test-specific method detection level reported that was also equal to or less than the average emissions level (*i.e.,* unadjusted for probability confidence level) calculated for the data set. We believe that this approach is representative of the data collected to develop the floor or emissions limit while to some degree minimizing the effect of a test(s) with an inordinately high method detection level (*e.g.,* the sample volume was too small, the laboratory technique was insufficiently sensitive, or the procedure for determining the detection level was other than that specified).

The second step in the process is to calculate three times the representative

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[5] American Society of Mechanical Engineers, *Reference Method Accuracy and Precision (ReMAP): Phase 1, Precision of Manual Stack Emission Measurements,* CRTD Vol. 60, February 2001.

method detection level[6] and compare that value to the calculated floor or emissions limit. If three times the representative method detection level were less than the calculated floor or emissions limit calculated from the upper prediction limit (UPL), we would conclude that measurement variability was adequately addressed because the measurement inprecision at that level is a consistent 10 to 15 percent. The calculated floor or emissions limit would need no adjustment. If, on the other hand, the value equal to three times the representative method detection level were greater than the UPL-based emission limit, we would conclude that the calculated floor or emission limit does not account entirely for measurement variability. If indicated, we substituted the value equal to three times the representative method detection level to apply as the adjusted floor or emissions limit. This adjusted value would ensure measurement variability is adequately addressed in the floor or the emissions limit.

In response to comments that EPA should have used the PQL, RL, or LOQ values in place of non-detect values, we disagree that use of those values is appropriate for calculating the MACT floors for two reasons. First, these terms are not defined statistically or consistently from method to method but are relatively arbitrary multiples (*e.g.,* 3 times, 5 times, or 10 times) of the MDL. In some cases, a RL, LOQ, or PQL is a value determined based on a laboratory-specific procedure and not standardized by the method. We could not apply data arbitrarily adjusted or subject to laboratory-specific variables in establishing the floor. Second, we used a value equal to three times a representative MDL to compare with the floor and to adjust the applicable emissions limit, if necessary. We believe that using a value equal to three times the MDL sufficiently accounts for measurement uncertainty for the purposes of establishing compliance and there is no need to try to define or apply a PQL, LOQ, or RL for this purpose.

4. Instrument Span for CO

Comment: Many commenters stated that the reported data and limits for CO are within the error range of analyzers and CO CEMS. For Method 10, the calibrated analyzers have an error of ±2 percent of the instrument span, with spans ranging from 50 parts per million (ppm) to 1000 ppm or greater. As such, at a minimum there is a potential error of 1 ppm to 20 ppm (2 percent of 50 ppm and 1000 ppm, respectively) while the liquid and other process gas categories have floor limits set at 1 ppm. Similarly, commenters noted that CO CEMS have an allowable drift of 5 percent of the span, with similar span ranges as Method 10. Commenters questioned the technical feasibility of complying with such low limits given the range in span values and suggested that EPA should review the data and establish more appropriate limits in consideration of measurement precision concerns.

Response: EPA agrees with the comment that many of the CO measurements are within the error range of analyzers, and EPA has taken steps to mitigate the potential bias of such measurements. The resulting emission limits represent a level of performance that has been demonstrated to be achieved by the average of the best performing 12 percent of sources while considering variability introduced by imprecision of the CO analyzers. As explained below, our assessment indicated that the site-specific estimated measurement errors in some cases may be higher than some of the reported emissions levels. Therefore, for each emission test used in the MACT floor calculations we substituted the site-specific estimated measurement error for reported values below those values in order to ensure the quality of the data used to set the floors.

In response to the comments received, we reviewed the quality of the data relative to information provided for each emissions test. Method 10 is structured such that we can assess measurement data quality relative to the calibration span of the instrument (see *http://www.epa.gov/ttn/emc/promgate/method10r06.pdf* and *http://www.epa.gov/ttn/emc/promgate/method7E.pdf).* For example, the allowable calibration error, system bias, and drift requirements are directly proportional to the site-specific instrument calibration span (*i.e.,* ± 2.0 percent of the calibration span value). For instrument calibration span values of 25 ppmv and less, the allowable calibration error, bias, or drift values are each ± 0.5 ppmv.

We can estimate the equivalent of the method detection level for a measurement with an instrumental test method (e.g., EPA Methods 3A, 6C, 7E, and 10) using a square root formula and these allowable data quality criteria. For example, in the case of a calibration span value of 25 ppmv, the square root formula (i.e., square root of the sum of the squares) would indicate a value of 0.9 ppmv. Consistent with the methodology we applied for non-instrumental methods, discussed in the previous comment response where we established limits no less than 3 times the MDL in order to avoid a large degree of measurement imprecision, this estimated measurement error value would translate to a limit of 3.0 ppmv (rounded up from 2.7 ppmv). For tests done with calibration spans of greater than 25 ppmv, the corresponding estimated measurement error would be greater. For example, the estimated measurement error using the square root formula for a calibration span of 100 ppmv would be about 4 ppmv which would translate to a limit of 12 ppmv. For a calibration span of 1000 ppmv, the estimated measurement error would be 35 ppmv or a limit of about 100 ppmv.

5. Achievability of Limits

Comment: Several commenters were concerned that only small subsets of sources in each subcategory have emissions stack test data. These commenters added that less data means the pool from which the best performing 12 percent of the existing sources are drawn is smaller and, therefore, the actual number of sources used to determine the MACT floor is smaller. The commenters suggested that EPA should collect more data or provide assurances that the limited available data are representative for each subcategory. Commenters suggested that EPA could supplement testing data with "emissions information" such as fuel records, production records and associated emission factors, commercial warranties and guarantees.

Commenters raised concerns that existing units would have difficulty demonstrating compliance with the MACT floor limits. They suggested best performers with advanced air pollution control technologies should not be required to install additional add-on equipment to meet the emission limits. Commenters requested that EPA assess how many existing boilers and process heaters in each subcategory will be able to meet the standards without taking any further control measures. Several commenters contacted manufacturers regarding a retrofit project for their boilers and process heaters and they noted that manufacturers were unwilling to guarantee a retrofit would meet the limits.

Similarly, commenters raised concerns that new units would have even more difficulty demonstrating compliance with the MACT floor limits. These commenters had difficulty identifying a single source whose emissions testing data demonstrated they could achieve all of the MACT

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[6] *Ibid.*

floors for new sources in combination. Several commenters contacted boiler and process heater manufacturers; all were unable to offer commercial emissions guarantees that a new unit would meet the proposed limits. Some commenters raised concerns about the impacts of these stringent new unit floors including: Deterring sources from upgrading to new boilers as efficiency gains provided by a new unit would be offset by extensive controls and threatening fuel diversity.

Some commenters expressed concern that EPA had not properly evaluated whether there are technically feasible means of achieving the MACT floors. The commenters contended that the approach does not identify reasons why best performing sources achieve emissions levels reflected in the test data and they suggested that the intent of the MACT floor standard setting process is to discover effective control techniques so that other performers in the source category could emulate those techniques, reduce their emissions, and achieve similar emission levels. Commenters added that EPA has not adequately considered air pollution control device (APCD) conflicts with one another or compatibility of controls on certain boilers. Additionally, choosing to optimize controls for one pollutant may preclude optimization of controls for another pollutant e.g., minimizing CO in the combustion system is opposed to minimizing NO_X in most boiler burners.

Response: As mentioned elsewhere in this preamble, EPA is required to establish MACT floor levels based on emissions limits achieved by sources for which emissions information is available to the Administrator. EPA has revised the proposed MACT floors as well as the proposed subcategories, as explained above. EPA also examined several ways in which it might be able to use other types of emissions information in addition to actual emissions measurements. However, EPA concluded that there was no appropriate method of using different types of information in a manner that could be incorporated into the variability analyses. EPA first assessed the potential for estimating emissions for sources that lacked actual emissions data through the use of emission factors. However, the emission factors lack any degree of variability. Therefore, the use of such data in this rulemaking would have distorted the data variability in many cases, leading to standards that were more stringent than those developed using emissions data only and that likely underestimated actual variability. EPA also considered whether it could otherwise estimate emissions of sources that did not provide emissions data. However, EPA concluded that such estimations were not possible without the development of a technically appropriate approach to evaluate relevant information, and commenters did not provide any such approaches. EPA's approach provides MACT floors that are consistent with the requirements of section 112, because the floors are based on the average emissions performance of the best performers for which the Administrator has emissions information that is appropriate to use in setting the floors.

EPA agrees with commenters who note that many of the data sets are small. However, stakeholders were encouraged to provide additional data, and EPA significantly revised some of the proposed emission limits based on new test data. We received little or no additional data for some subcategories for which data sets were small at proposal. For all data sets, the final emission limits are based on the available data and reflect EPA's assessment of variability. Moreover, after consideration of the comments on the achievability of the emission limits, EPA performed additional analyses and detailed examinations of the data and developed revised limits that are based on what has been demonstrated to be achieved in practice. As described in more detail in the docket memorandum entitled "Revised MACT Floor Analysis (2011) for the Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants—Major Source," EPA has made adjustments to treatment of non-detect values, the statistical methodology, and monitoring requirements, and also incorporated new data and data corrections into our analyses. Accordingly, the final emission limits better reflect the performance of the MACT floor units than the proposed limits. EPA notes that for each subcategory, there are existing units that are meeting the MACT floor limits or are expected to meet the limits through application of available control technology.

Finally, in response to comments about low CO limits conflicting with a unit's ability to meet NO_X requirements, EPA does not have specific information on the NO_X limits and NO_X emissions for most of the units that will be subject to the standard. However, the CO limits have been revised as discussed elsewhere in this preamble, and compliance is based on a full load test, while periods of startup and shutdown are subject to a work practice standard. To the extent that units cannot meet the CO floor and maintain NO_X at the required level, oxidation catalysts can be used to reduce CO without an increase in NO_X. EPA has included costs for these controls for many units in the cost analysis, although data on NO_X requirements were not sufficient to allow NO_X to be part of the analyses. Commenters did not provide any data supporting claims that any of the other emission limits or projected control devices would interfere with a source's ability to meet any of the other emission limits.

6. Comments on Technical Approaches

Comment: Several commenters offered suggestions for adjusting the treatment of data from common stacks. Commenters suggested that it is improper to count the data twice if two boilers, in the same subcategory, exhaust through a common stack. A test conducted on the common stack does not represent the actual emissions from a single boiler, but rather reflects emissions from the combined simultaneous operation of the two boilers and their associated control device(s). The commenters contended that it is impossible to claim the test result would be exactly the same for each boiler and they added that if a common stack test turns out to be in the lowest 12 percent in a subcategory, counting it twice distorts the average of the best performers and skews the variability calculations. Commenters also noted that it is also not appropriate to divide emissions evenly between each boiler. Instead these commenters suggested that EPA use the data from common stacks only a single time in the MACT floor ranking and UPL calculations.

Response: EPA's current approach is a reasonable approach for comingled emissions, particularly in light of the limited dataset available for some subcategories, because EPA can not accurately separate the fraction of the emissions that came from the combustion units and process emission points that are comingled in the same stack. Applying the emissions equally to multiple units exhausting through a common stack accurately represents the emissions of those units on average. Further, although the use of a data point twice may dampen variability, the inclusion of an extra unit in the floor has the opposite effect on the overall emission limit by increasing the denominator of the floor calculation. Either method could be used, but the results would not differ significantly. Furthermore, for existing sources, MACT cannot be less stringent than the average emission limitation achieved by the best performing 12 percent of existing sources (for which emission information is available). If EPA ignored boilers that exhaust through a common stack, it would be ignoring available emissions information that is relevant to setting the MACT floor standards.

Comment: Some commenters raised concerns that the MACT floor methodology doesn't adequately address the inherent variability with respect to operating conditions and control device performance. Operational variability can include warm-ups, shutdowns, load swings, and variations in fuel quality. They contended that emissions data relied upon in the proposal were produced during reference method performance testing under very limited operating conditions and with a very limited variation in potential fuel quality. Other commenters raised concerns that EPA has not properly acknowledged the impact of fuel quality on emissions. One commenter urged caution to EPA when considering variability to generate compliance margins that are palatable to industry; suggesting that this concept is not incorporated in the statute.

Response: EPA is mindful of the need to account for sources' variability in assessing sources' performance when developing technology-based standards. EPA reviewed subcategory floor calculations in light of these comments and believes that the two-step MACT floor analysis process adequately addresses: (1) Performance testing variability and (2) fuel analysis variability estimations. EPA revised the MACT floor calculations in light of data submitted during and after the public comment period and also modified the approaches used at proposal for various aspects of the floor calculations.

EPA first took fuel into consideration, to the extent it is reflected in differences in boiler design, when we divided the source category into subcategories. EPA is aware that differences between given types of units, and fuel, can affect technical feasibility of applying emission control techniques, and has addressed this concern in the final rule. For a fuel based pollutant, such as PM, performance testing must be conducted under representative full load operating conditions, which, along with the parameter monitoring requirements, provides an assurance that the standards are being met at all times. For Hg and HCl, we modified the fuel based variability analysis in consideration of comments received on this approach. The first modification to the analysis was the introduction of a solid fuel subcategory, which includes any unit burning at least 10 percent, on an annual heat input basis, of any coal, fossil solid, biomass, or bio-based solid fuel. Given the wide variety in fuel types that compose the floor, the statistical analysis accounts for some of the inter-unit variability for different fuel types identified to be in the floor. The second modification was the development of a fuel variability factor (FVF). The FVF calculations were similar to the calculations used at proposal, but they were simplified to remove the control efficiency calculation and the method for identifying outliers in the data was also adjusted. The revised FVF analysis calculated a ratio for all fuel analysis data points for units in the top 12 percent for existing units and the top performing unit for new units in each subcategory. This ratio compared the reported fuel analysis data, converted to units of lb/MMBtu, to the emission test outlet data, converted to units of lb/MMBtu, during the stack tests. At proposal we conducted an outlier analysis of only the maximum ratios for each unit, but we revised the outlier analysis to consider all of the ratios from top performers within each subcategory. We then defined and identified outliers using the test of 3 times the standard deviation and 3 minus the standard deviation for all of the ratios in the subcategory. After removing outliers, the remaining maximum ratio for each subcategory was identified and multiplied by the 99 percent UPL.

For a discussion of how EPA considered other non-fuel variability operations, such as boiler load, see response to the comments provided under "What did we do with the CO Limits".

Comment: Several commenters argued that it is inappropriate to rank units according to the minimum stack test since any boiler can experience a good compliance test if conditions are favorable. Many of these commenters suggested that EPA should instead rank the data on the average of all stack tests. Another commenter suggested that the different emission levels achieved by different sources are just differences in performance and basing the ranking on the average would be more appropriate. This commenter suggested that at a minimum, the data used to rank and the data used as inputs into the MACT floor upper prediction limit calculation should be consistent.

Response: In this final rule, EPA has reasonably determined that the best-controlled source is the source with the lowest stack test. EPA selected the lowest stack test as a measure of best performer because many units had only a single test available, and the comparison of average performance from two or more tests is not directly comparable to a single test measurement. However, all emission tests of acceptable quality were used to assess variability. As such, all data were considered in the floor analyses. EPA recognizes that each stack test data point represents a true assessment of the emissions for a combustor at a given point in time. However, where units had more than one test available, EPA also considers these other tests to be representative of the unit and relevant to assess run-to-run and test-to-test variability in the MACT floor UPL calculation. EPA did screen and remove certain test data from the MACT floor calculations if that data were not deemed representative of current operating conditions.

7. Statistical Approach

There were several comments made on specific aspects of the statistical variability analysis including suggestions for the appropriate confidence interval, appropriate statistic, and EPA's methods for determining the distribution of the dataset. The specific comments and EPA responses are outlined below.

Comment: Industry, industry representatives, and environmental advocacy groups had different perspectives on the appropriateness of the proposed 99 percent UPL. Commenters from environmental advocacy groups requested a lower UPL with suggestions ranging between 50 to 95 percent. One commenter stated that EPA over-counts for the potential for future variability by using the 99 percent UPL for the entire data set and it does not adequately account for all variability, such as how unit maintenance and operator training may limit upward variability's effect on emission levels, and requests that EPA explain and justify the selection of the 99 percent UPL as opposed to the 90 or 95 percent UPL. Another commenter stated that most statistical analyses use 90 or 95 percent confidence intervals and prediction intervals. The commenter also claimed that 99 percent is overly conservative and results in twice as much HAP emissions and reduced health benefits compared to a lower UPL. Consequently the commenter stated a lower UPL would better withstand judicial review. One commenter mentioned that there is precedent for setting limits based on the 90th percentile and cited a 2006 analysis where EPA determined the best demonstrated technology, which found Hg reductions based on 90th percentile and deemed the 90th percentile "reasonable" because of how compliance was to be determined and the high Hg content of the fuel used when the emissions data were collected. These commenters also suggested that EPA did not provide adequate rationale for selecting the 99th percentile instead of the 50th. These commenters noted that civil enforcement of environmental standards is based on a "preponderance of the evidence" which merely requires that a violation be more likely than not.

Commenters from industry and industry representatives advocated for a higher UPL. Commenters requested that EPA increase the UPL to 99.9 percent in order to better encompass unit emissions variability and represent a manageable risk. Industry, like environmental advocacy groups, also requested that EPA take into account operator training and its effect on emissions. The commenters claimed that operators are compelled to set emissions targets lower than limits to create a compliance margin which helps avoid violations and their consequences. Commenters also cited recent consideration of a 99.9 percent UPL in the proposed HMIWI MACT rule. Commenters claimed that since the HMIWI database consisted of a small dataset, it was unlikely full variability was observed and thus EPA had no valid statistical basis for the decisions to use 99 percent in the final HWIMI rule. The commenters suggested similar data limitations in the boiler dataset and argued that the 99.9 percent UPL should be used to allow more of a margin for all operating conditions and sample collection variation due to the limited data for the boiler MACT rule.

Response: In this final rule, EPA has reasonably determined that 99 percent UPL is appropriate for fuel based HAP, and dioxin/furan, and a 99.9 percent UPL is appropriate for CO. For fuel-based HAP the 99 percent confidence level is consistent with other recent rulemakings. See 75 FR 54975. Many of the subcategories had limited data to establish the MACT floor calculations and EPA determined it was inappropriate to use a confidence level lower than 99 percent to set the standard because doing so would result in limits that the best performers would be expected to exceed, while this final rule requires that units meet the limits at all times. Finally, for the fuel-based pollutants, there are well established control measures currently used on units in the source category (fabric filters for PM and Hg and wet or dry scrubbers for HCl) that serve to mitigate, to some degree, the variability in emissions that can be expected. Given this additional consideration for fuel-based HAP, but recognizing the emission limits must be met at all times yet are based on short term stack test data, EPA selected the 99 percent confidence level. A lower confidence level would result in emission limits that even the best performing sources would be expected to exceed.

For CO, EPA considered several comments from industry and States, which provided both quantitative and qualitative comments on how CO emissions vary with load, fuel mixes and other routine operating conditions. After considering these comments EPA determined that a 99.9 percent confidence level for CO would better account for some of these fluctuations. While a good deal of CO data are available, at least for some of the subcategories, the data show highly variable emissions that can result from situations beyond the control of the operator, such as fuel moisture content after a rain event, elevated moisture in the air, and fuel feed issues or inconsistency in the fuel. The higher confidence level selected for CO is intended to reflect the high degree of variability in the emissions. For dioxin/furan, we also are maintaining the 99 percent UPL. Although much of the uncertainty associated with dioxin/furan testing will be mitigated by the requirement in EPA Method 23 to report non-detect values as zero for compliance purposes, the dioxin emission limits remain quite low and the 99 percent UPL provides a high degree of confidence that the best performing units will be able to meet the standards.

Comment: Several commenters also addressed concerns with how EPA determined the distribution of the dataset. Many commenters stated that normal distribution theory has been incorrectly applied to positively skewed or log normally distributed emissions data. Based on this, commenters claimed that sample means, and consequently the 99 percent UPL calculation, were incorrectly determined. Commenters suggested that sample means should be computed based on the arithmetic mean of lognormal distribution. One commenter requested that EPA consider using non-normal distributions or non-parametric methods in the analysis. Two commenters noted that the technique used by EPA based on logarithmic transformation underestimates the prediction limit for the mean and requested that EPA use the 2004 Bhaumik and Gibbons procedure for computing the UPL for log-normally distributed data. Three commenters stated that EPA is not following its own guidance document, *Data Quality Assessment: Statistical Methods for Practitioners EPA QA/G–9S,* for determining whether or not a data set is normally distributed and should explain the reasons for not doing so. The commenters then go on to request that EPA follow its guidance documents which recommend use other tests aside from the skewness and kurtosis tests when data are limited or if critical test values are not available.

Response: EPA appreciates the detailed suggestions for alternative approaches to determine the dataset and it has revised its default selection of data distributions consistent with its guidance document *Data Quality Assessment: Statistical Methods for Practitioners EPA QA/G–9S.* This document indicates that most environmental data are lognormally distributed, so EPA has modified its assumptions when the results of the skewness and kurtosis tests result in a tie, or when there are not enough data to complete the skewness and kurtosis tests. Some of the commenters suggested that more advanced tests are necessary to determine the dataset, such as the Shapiro-Wilkes test. These tests needs a sample size of 50 or more, and would not be appropriate for many of the small sample sizes used to compute the MACT floor UPL.

With respect to the methods used to compute the UPL for a dataset that is determined to be lognormally distributed, EPA also considered the commenters suggested revisions to the calculations in order to avoid skewing the UPL by calculating the UPL of an arithmetic mean instead of the UPL of a geometric mean. To adjust the calculation EPA considered a scale bias correction approach as well as a new UPL equation based on a Bhaumik and Gibbons 2004 paper, which calculates "An Upper Prediction Limit for the Arithmetic Mean of a Lognormal Random Variable". Given data availability, EPA selected the Bhaumik and Gibbons 2004 approach which addresses commenters concerns with the proposed computations.

Comment: Several commenters suggested alternatives to the UPL statistics such as upper tolerance limit (UTL), upper limit (UL) and upper confidence limit (UCL). Several commenters stated that EPA's UPL calculation was flawed and did not fully account for variability. Commenters then suggested that if the proposed UPL approach was maintained EPA should adopt the modified UPL equation in the Portland cement NESHAP. Commenters argued that this statistic would represent floors achieved in practice and account for total variability instead of EPA's proposed UPL statistic based on sample variability. Several commenters claimed the data set was limited and suggested that EPA should use the UTL when data available do not represent the entire population. One commenter claimed that the upper UCL used in the HMIWI MACT rule was not a true prediction limit because it did not adjust the standard deviation for the number of test runs in the future compliance average and it should not be used in the boiler MACT rule.

Response: EPA considered these comments and reviewed each of the separate statistics. Because statistics is a tool and many statistical approaches could be considered valid, EPA considered the comments and adjusted the approach used to provide a reasonable and technically correct statistical methodology. MACT floors for existing sources must reflect the average emission limitation achieved by the best-performing 12 percent of existing sources. As explained below, only the UCL and UPL adequately get at the notion of average emissions. Use of the UPL is also consistent with other recent rulemakings. *See* 75 FR 54975.

In general, confidence intervals are used to quantify one's knowledge of a parameter or some other characteristic of a population based on a random sample from that population. The most frequently used type of confidence interval is the one that contains the population mean. Given this definition, the 99 percent UCL represents the value which we can expect the mean of the population to fall below 99 percent of the time in repeated sampling. Whereas a confidence interval covers a population parameter with a stated confidence, that is, a certain proportion of the time, there is also a way to cover a fixed proportion of the population with a stated confidence. Such an interval is called a tolerance interval. Confidence limits are limits within which we expect a given population parameter, such as the mean, to lie. Statistical tolerance limits are limits within which we expect a stated proportion of the population to lie. Given these definitions, the 99 percent UTL represents the value which we can expect 99 percent of the measurements to fall below 99 percent of the time in repeated sampling. In other words, if we were to obtain another set of emission observations from the five sources, we can be 99 percent confident that 99 percent of these measurements will fall below a specified level. Since you must calculate the sample percentile, and the sample sizes for the boiler MACT floor data are small, the 99th percentile is underestimated. The UTL should only be used where one can calculate a sample percentile, *e.g.,* where there is a sample size of at least 100, and we do not have that many sources represented in any MACT floor.

In contrast to a confidence interval or a tolerance interval, a prediction interval for a future observation is an interval that will, with a specified degree of confidence, contain the next (or some other pre-specified) randomly selected observation from a population. In other words, the prediction interval estimates what future values will be, based upon present or past background samples taken. Given this definition, the UPL represents the value which we can expect the mean of 3 future observations (3-run average) to fall below, based upon the results of the independent sample of size n from the same population. Finally, the upper limit (UL) is roughly equivalent to the percentile of the actual data distribution for the sample. The UL does not have a robust statistical foundation. Basically, the UL formulation assumes that the data: (1) Represent the population rather than a random sample from that population, and (2) are normally distributed. The data used to develop the MACT floors for this rule do not represent the entire population for any subcategory, and most of the data sets are not normally distributed. For these reasons, EPA concluded that it is not appropriate to use the UL in setting the MACT floor limits.

Comment: Some commenters suggested that EPA's UPL approach fails to accomplish predicting the level of performance achieved by the best performing sources under all operating conditions, not because of a poor statistical framework but because of an inadequate database. These commenters added that as a result, the inputs into the UPL equations are not representative of a distribution of values that reflect all operating conditions.

Response: Section 112(d) of the Act requires EPA to base MACT floor standards for existing sources on the average emission limitation achieved by the best performing 12 percent of existing sources for which EPA has emissions information. EPA has incorporated new data and data corrections received during the public comment period. EPA also has considered the requests for further subcategorization of the source category in light of limits on the dataset that caution against over-partitioning of the database. The revised analysis is based on all emission stack test data of appropriate quality available to EPA, and the UPL approach provides as complete a picture of variability as possible given the limited data available.

Comment: Some commenters questioned whether the statistical approach met EPA's legal obligations under Section 112 of the CAA. One commenter stated that in order to withstand judicial review, the UPL should be calculated based on the best 6 percent of sources instead of the best 12 percent in order to establish a floor that would require 94 percent of sources to reduce emissions. One commenter stated that the courts did not endorse the proposed UPL procedure and that its appropriateness should be reviewed. The commenter goes on to say that on a statistical and technical basis, the UPL procedure is antithetical to the instruction in Section 112(d)(3)(A) and contradicts the strong endorsement of the high floor implementation as the best reading of the statutory language.

Response: While the commenter is correct that the entire MACT floor data pool was used in the calculation of the UPL, EPA notes that statistics is a tool that is used to estimate variability and it is entirely appropriate to consider the variability within the best forming 12 percent of sources in developing emission limits based on the average performance of those sources. As far as the concept that the floors should require 94 percent of the sources to reduce emissions, that is not what is required by the statute. Rather, the statute requires that the MACT floor standards for existing sources be no less stringent than the average emission limitation achieved by the best performing 12 percent of existing sources for which EPA has emissions information. For example, if a category had 100 units and the performance of the best 50 of those units was the same, the emission limits would be based on those 50 units and they all would be projected to meet the limits. While this is a hypothetical scenario, it illustrates that there is no specific percentage of sources that must reduce emissions in order for the MACT floor limits to be consistent with the statutory requirement.

Comment: One commenter suggested that EPA should incorporate different statistical methods according to the amount and type of data available in each subcategory instead of a one-size-fits-all approach. This commenter also suggested that the approach taken by EPA must be validated by looking at the result it creates and examining whether the end result is reasonable. The commenter suggested applying a simple test to identify whether the resulting floor requires a substantial majority of each subcategory to make some degree of emission reduction.

Response: EPA has revised its statistical approach to include a mixed use of confidence levels, as discussed above, as well as a mix of statistical tools to consider the distribution of the datasets and what types of data are used as inputs into the floor analysis. For example, the MACT floor computations for Hg emissions from liquid fuel units were modified to consider data from both fuel analysis and stack test results. EPA appreciates the suggestion for validating the results of the statistical computations and has determined that the final floor levels require a significant number of sources to make some degree of emission reduction. However, EPA also notes that the number of sources that will need to achieve some degree of emissions reduction from current levels is not the statutory basis for establishing emissions standards under section 112(d), as noted above.

Comment: One commenter representing manufacturers of monitoring and control technologies suggested that statistical variability should not be incorporated into the floor computations for CO and Hg. This commenter suggested that EPA base the floors on the straight averages of each data set.

Other commenters suggested that emissions variability is not statistical but instead based on different operating conditions of individual units. The commenters added that the variability of each unit should be averaged based on individual units and then used to establish UPL calculations instead of assessing a UPL based on individual tests or test runs.

Response: The UPL calculation is a statistical formula designed to estimate a MACT floor level that is equivalent to the average of the best performing sources based on future compliance tests. If we did not account for variability in this manner and instead set the limit based solely on the average (mean) performance, then these units could exceed the limit half the time or more. The MACT floors for existing sources must reflect the average emission limitation achieved by the best-performing 12 percent of existing sources. Therefore, it is appropriate to consider statistical variability in order to ensure that units could meet the floors at all times. EPA agrees with the commenter that the variability of emissions is not solely statistical, but also represents some operational variability that may occur between different tests at the same unit (intra-unit variability) as well as different tests at different units (inter-unit variability) in the floor. Since the floor calculations represent the average of the best-performing 12 percent of existing sources, it is reasonable for EPA to use an appropriate statistical analysis to assess the impact both intra-unit and inter-unit variability have on the emissions profiles.

8. Alternative Units for Emission Limits

Comment: Several commenters from industry, State agencies, and environmental non-governmental organizations submitted a variety of alternatives to the concentration-based and mass-based MACT floor limits. Some commenters suggested emission reductions or removal efficiencies. These commenters cited regulatory precedence for a percent reduction limit in 40 CFR part 60 subpart Db, the New Source Performance Standards for Industrial, Commercial Institutional Boilers as well as New Source Performance Standards and Emission Guidelines for Large and Small Municipal Waste Combustors (40 CFR part 60 subparts Ca, Cb, Ea and Eb). Several other commenters suggested that EPA adopt an alternative output-based emissions standard to promote boiler efficiency improvements as a pollution prevention technique. One commenter called attention to several previous examples of output-based standards in recent air regulations, including the New Source Performance Standard for Electric Utility Steam Generating Units (40 CFR part 60 subpart Da) which includes an output-based emissions standard for Hg, PM, SO_2, and NO_X) as well as the New Source Performance Standard for Industrial Commercial Institutional Boilers (40 CFR part 60 subpart Db) which includes an output-based emissions standard for NO_X. This commenter also provided examples of output-based emissions regulations in 12 states, including 4 that regulate non-electricity thermal output, such as from combined heat and power systems. Many commenters encouraged EPA to investigate opportunities to develop and implement output-based emissions standards for ICI facilities. Some commenters tied in the appropriateness of output-based standards to the Agency's other pollution prevention techniques included in the proposal, such as the energy assessments. The commenter added that by providing an output-based regulatory option, the user will have further incentive to implement energy efficiency opportunities identified during the energy assessment.

Response: With respect to the commenters' request for the development of percent reduction standards, sufficient data were not available to determine the percent reduction from the best performing units. In order to determine such standards, we would need emissions data from testing conducted at both the APCD inlet and outlet for the best performing sources, or at least for a reasonable number of best performing sources. However, we only have APCD inlet and outlet data for one pollutant (PM) for two subcategories, and based on this overwhelming lack of data available to calculate percent reduction standards, EPA did not pursue this option. We do agree with the commenters that output-based standards would provide incentives for implementation of energy conservation measures identified in an energy assessment. This final rule includes a compliance alternative that allows owners and operators of existing affected sources to demonstrate compliance on an output-basis. This alternate output-based limit will promote energy efficiency in industrial, commercial, and institutional steam-generating facilities, and are equivalent to the MACT emissions limits that are in heat-input format. EPA has established pollution prevention as one of its highest priorities. One of the opportunities for pollution prevention lies in simply using energy efficient technologies to minimize the generation of emissions. Therefore, as part of EPA's general policy of encouraging the use of flexible compliance approaches where they can be properly monitored and enforced, we are including alternate output-based emission limits in this final rule. The alternate output-based emission limits provide sources the flexibility to comply in the least costly manner while still maintaining regulation that is workable and enforceable. We investigated ways to promote energy efficiency in boilers by changing the manner in which we regulate flue gas emissions. The alternate output-based emission limits further this goal without reducing the stringency of the emissions standards.

Traditionally, boiler emissions have been regulated on the basis of boiler input energy (lb of pollutant/MMBtu heat input). However, input-based limitations allow units with low operating efficiency to emit more of each pollutant per output (steam or electricity) produced than more efficient units. Considering two units of equal capacity, under current regulations, the less efficient unit will emit more pollutants because it uses more fuel to produce the same amount of output (steam or electricity) than a more efficient unit. One way to regulate mass emissions and encourage plant efficiency is to express the emission standards in terms of output energy. Thus, output-based emission standards provide a regulatory incentive to enhance unit operating efficiency and reduce emissions. An example of such an output-based standard is the NO_X standard under the New Source Performance Standards (subpart Da) for electric utility boilers.

The criteria used for selecting a specific output-based format were based on the following: (1) Provide flexibility in promotion of plant efficiency; (2) permit measurement of parameters related to stack emissions and plant efficiency, on a continuous basis; and (3) be suitable for equitable application on a variety of facility configurations. The output-based option of mass of pollutant emitted per boiler energy output (lb/MMBtu energy output) meets all three criteria. The majority of ICI boilers produce steam only for process operation or heating and, in this case, the energy output of the boiler is the energy content of the boiler steam output. For those ICI boilers that supply steam to generate, or cogenerate, electricity, the boiler's energy output can include both electrical and thermal (process steam) outputs. There are also some industrial boilers that only generate electricity. Technologies are readily available to measure these energy outputs, and they currently are measured routinely in many industrial plants. Therefore, emission limits based on this format can be applied equitably on a variety of facility configurations. Based on this analysis, an emission limit format based on mass of pollutant emissions per energy output was selected for the alternate output-based standards.

In the case of a boiler that produces steam for process or heating only (no power generation), the lb/MMBtu output-based emission limit is based on the mass rate of emissions from the boiler and the energy content in terms of MMBtu of the boiler steam output. At cogeneration facilities (also known as combined heat and power (CHP)), energy output includes both electricity and process steam. The steam from the boiler is first used to generate electricity. The thermal energy (steam) exiting the electricity generating equipment is then used for a variety of useful purposes, such as manufacturing processes, space heating and cooling, water heating, and drying. The electricity output and the useful energy present in the steam exiting the turbine must both be accounted for in determining the overall energy output from the boiler and converted to a common basis of lb/MMBtu consistent with the output-based standard for steam-only units.

The efficiency and associated environmental benefits of CHP result from avoiding emissions from the generation of electricity at a central station power plant. The avoided emissions at most times are from a less-efficient unit that consequently also has higher emissions. Consequently, the electricity output of the CHP facility in kWh should be valued at the equivalent heat rate of the avoided central station power, nominally 10,000 Btu/kWh. Therefore, the lb/MMBtu output-based emission limit used for compliance with a CHP boiler is based on the mass rate of emissions from the boiler and a total energy output, which is the sum of the energy content of the steam exiting the turbine and sent to process in MMBtu and the energy of the electricity generated converted to MMBtu at a rate of 10,000 Btu per kWh generated (10 MMBtu per MWh).

Compliance with the alternative output-based emission limits would require continuous measurement of boiler operating parameters associated with the mass rate of emissions and energy outputs. In the case of boilers producing steam for process use or heating only (no power generation), the boiler steam output flow conditions would have to be measured to determine the energy content of the boiler steam output. In the case of CHP plants, where process steam and electricity are output products, methods would have to be provided to measure electricity output and the flow conditions of the steam exiting the electrical generating equipment and going to process uses. These conditions will determine the energy content of the steam going to process uses. Instrumentation already exists in many facilities to conduct these measurements since the instrumentation is required to support normal facility operation. Consequently, compliance with the alternate output-based emission limits is not expected to require any additional instrumentation in many facilities. However, additional signal input wiring and programming is expected to be required to convert the above measurements into the compliance format (lb/MMBtu energy).

Since the June 4, 2010, proposal, we obtained steam data (flow, temperature, and pressure) from the best performing units that made up the MACT floor at proposal. In determining alternate equivalent output-based emission limits, we first determined for each of the best performing units the Btu output of the steam and then calculated the boiler efficiency for each of the boilers having available steam/heat input data. Boiler efficiency is defined as steam Btu output divided by fuel Btu input. Next, we determined the average boiler efficiency factor for each subcategory from the best performing units in that subcategory. We then applied the average boiler efficiency factor to the final MACT limits that are in the current format of lb/MMBtu heat input to develop the alternate output-based limits. The efficiency factor approach was selected because the alternative of converting all the reported data in the database to an output-basis would require extensive data gathering and analyses. Applying an average boiler efficiency factor, based on the individual boiler efficiency of the best performing units, essentially converts the heat input-based limits to output-based emission limits.

The alternate output-based emission limits in this final rule do not lessen the stringency of the MACT floor limits and would provide flexibility in compliance and cost and energy savings to owners and operators. We also have ensured that the alternate emission limits can be implemented and enforced, will be clear to sources, and most importantly, will be no less stringent than implementation of the MACT floor limits.

B. Beyond the Floor

1. Energy Assessment Requirement

Comment: In the proposal preamble, we solicited comments on various aspects of the energy assessment requirement. The proposed standards included the requirement to perform an energy assessment to identify cost-effective energy conservation measures. Since there was insufficient information to determine if also making the implementation of cost-effective measures a requirement was economically feasible, we requested comment on this point. We also specifically requested comment on: (1) Whether our estimates of the assessment costs are correct; (2) is there adequate access to certified assessors; (3) are there organizations other than for certifying energy engineers; (4) are online tools adequate to inform the facility's decision to make efficiency upgrades; (5) is the definition of "cost-effective" appropriate in this context since it refers to payback of energy saving investments without regard to the impact on HAP reduction; (6) what rate of return should be used; and (7) are there other guidelines for energy management beside ENERGY STAR's that would be appropriate. The energy assessment requirement has been revised in this final rule and alternate equivalent output-based emission limits have been incorporated into this final rule as an alternative means of complying with the emission limits in final rule. The alternate output-based emission limits allow a facility implementing energy conservation measures that result in decreased fuel use to comply with that emission limit by applying emission credits earned from the implementation of the energy conservation measure.

Commenters stated that EPA should provide a clear, statutory-based definition of "Boiler," and the scope of the required energy assessment. Commenters also stated that if EPA includes an energy assessment requirement in this final rule, it should regulate only the emission source over which it has § 112 authority to regulate. The "boiler" logically includes the combustion unit (the emissions source) and closely associated equipment, from flame to last heat recovery. EPA should adopt this definition of "boiler system," which reflects the extent of its section 112 authority.

Commenters also recommended that an energy assessment previously conducted of a facility that has not had significant changes to the boilers and associated equipment should be acceptable for initial compliance. Energy performance of facilities strongly depends on equipment configuration, equipment performance, and fuels fired. If these do not change from the time an energy assessment was conducted to the time the Initial Compliance energy assessment report is submitted, the report would be representative of an accurate depiction of the facility.

Several commenters supported the use of energy assessments as a "beyond the floor" control measure and advocated for output-based standards (noting that such an approach is critically important to encourage CHP since input-based emissions regulations fail to credit CHP systems for their greater efficiency, reducing the incentive for CHP to be installed and used throughout U.S. industry). Moreover, since this final boiler rule will apply to a wide variety of manufacturing facilities in multiple sectors producing a variety of final products, normalizing pollutant output per useful energy output is a good way to ensure all affected facilities can be assessed on similar baselines. Several commenters also applauded recognition of energy efficiency measures to achieve pollution reductions and encouraged EPA to continue to view energy efficiency investments favorably. Some commenters criticized EPA's failure to require implementation of findings of the energy assessments.

Response: We agree that EPA should provide a clear definition of what the energy assessment should encompass. However, we disagree that the energy assessment should be limited to only the boiler and associated equipment, and in fact the proposed rule included a broader scope. EPA has properly exercised the authority granted to it pursuant to CAA section 112(d)(2) which states that "Emission standards promulgated * * * and applicable to new or existing sources shall require the maximum degree of reduction in [HAP] emissions that the Administrator determines * * * is achievable * * * through application of measures, processes, methods, systems or techniques including, but not limited to measures which * * * reduce the volume of, or eliminate emissions of, such pollutants through process changes, substitution of materials or other modifications * * *." The energy assessment requirement is squarely within the scope of this authority. The purpose of an energy assessment is to identify energy conservation measures (such as process changes or other modifications to the facility) that can be implemented to reduce the facility energy demand from the affected boiler, which would result in reduced fuel use. Reduced fuel use will result in a corresponding reduction in HAP, and non-HAP, emissions from the affected boiler.

We agree that the scope of the required energy assessment presented in the proposed rule needs to be clarified and we have done this in this final rule. In the proposed Boiler MACT, the intended scope of the energy assessment did extend beyond the affected boiler. The energy assessment included a requirement that a facility energy management program be developed. The energy assessment was intended to be broader than the affected boiler and process heater and included other systems or processes that used the energy from the boiler and process heater. We disagree that the scope of the energy assessment should be limited to the boiler and directly associated components such as the feed water system, combustion air system, fuel system (including burners), blow down system, combustion control system, and heat recovery of the combustion fuel gas. Including all of the energy using systems in the energy assessment can result in decreased fuel use that results in emission reductions, the result articulated in 112(d)(2). We have included in this final rule a definition of what the energy assessment should include for various size fuel consuming facilities. We also have included a definition of the qualified assessors who must be used to conduct those energy assessments. We have clarified the requirement that the energy assessment include a review of the facility's energy management program and identify recommendations for improvements that are consistent with the definition of an energy management program. A definition of an energy management program that is compatible with the ENERGY STAR Guidelines for Energy Management and other similar approaches was added.

We also agree that a facility should be exempt from the requirement to conduct an energy assessment if an energy assessment has recently been conducted. We have revised the final rule to allow facilities to comply with the requirement by submitting an energy assessment that has been conducted within 3 years prior to the promulgation date of this final rule.

Comment: The principle arguments against an energy assessment requirement are: (1) EPA lacks authority to impose requirements on portions of the source that are not designated as part of the affected source, such as non-emitting energy using systems at a facility; (2) EPA has not quantified the reductions associated with the energy assessment requirement, therefore it cannot be "beyond the floor;" and (3) the bare requirement to perform an audit without being required to implement its findings is not a standard under CAA section 112(d).

Response: With respect to the first argument, we have carefully limited the requirement to perform an energy audit to specific portions of the source that directly affect emissions from the affected source. The emissions that are being controlled come from the affected source. The process changes resulting from a change in an energy using system will reduce the volume of emissions at the affected source by reducing fuel consumption and the HAP released through combustion of fuel. The requirement controls the emissions of the affected source and, as explained above, is within the scope of EPA's authority under section 112(d)(2).

With respect to the second argument, the energy assessment will generate emission reductions through the reduction in fuel use beyond those reductions required by the floor. While the precise quantity of emission reductions will vary from source to source and cannot be precisely estimated, the requirement is clearly directionally sound and thus consistent with the requirement to examine beyond the floor controls. By definition, any emission reduction would be cost effective or else it would not be implemented.

Finally, with respect to the third argument, the requirement to perform the energy audit is, of course, a requirement that can be enforced and thus a standard. As noted, while we do not know the precise reductions that will occur at individual sources, the record indicates that energy assessments reduce fuel consumption and that parties will implement recommendations from an auditor that they believe are prudent. Therefore, the requirement to perform an energy assessment can both be enforced and will result in emission reductions.

We agree that EPA should provide a clear definition of what the energy assessment should encompass. However, we disagree that the energy assessment should be limited to only the boiler and associated equipment. EPA has properly exercised the authority granted to it pursuant to CAA section 112(d)(2) which states that "Emission standards promulgated * * * and applicable to new or existing sources shall require the maximum degree of reduction in [HAP] emissions that the Administrator determines * * * is achievable * * * through application of measures, processes, methods, systems or techniques including, but not limited to measures which * * * reduce the volume of, or eliminate emissions of, such pollutants through process changes, substitution of materials or other modifications * * *." The purpose of an energy assessment is to identify energy conservation measures (such as, process changes or other modifications to the facility) that can be implemented to reduce the facility energy demand from the affected boiler which would result in reduced fuel use. Reduced fuel use will result in a corresponding reduction in HAP, and non-HAP, emissions from the affected boiler. Reducing the energy demand from the plant's energy using systems can result in additional reductions in fuel use and associated emissions from the affected boilers. We agree that the scope of the required energy assessment needs to be clarified. However, in the proposed Boiler MACT, the intended scope of the energy assessment did extend beyond the affected boiler. The energy assessment did include a requirement that a facility energy management program be developed. The energy assessment was intended to be broader than the affected boiler and process heater and included other systems or processes that used the energy from the boiler and process heater. We disagree that the scope of the energy assessment should be limited to the boiler and directly associated components such as the feed water system, combustion air system, fuel system (including burners), blow down system, combustion control system, and heat recovery of the combustion fuel gas. Including the facility's energy using systems and energy management practices in the energy assessment can identify measures that result in decreased fuel use and related emission reductions. We have included in this final rule a definition of what the energy assessment should include for various size fuel consuming facilities. We also have included a definition of the qualified assessors who must be used to conduct those energy assessments.

We also agree that a facility should be exempt from the requirement to conduct an energy assessment if an energy assessment had recently been conducted. We have revised this final rule to allow facilities to comply with the requirement by submitting an energy assessment that had been conducted within 3 years prior to the promulgation date of this final rule.

C. Rationale for Subcategories

Many commenters stated that EPA should have proposed more subcategories, while others believed that too many subcategories were proposed. Many different issues were raised, and some of the key issues that led to changes in the rule include: The need for a limited use subcategory for boilers that operate for only a small percentage of hours during a year; the unique suspension/grate design of units that combust bagasse; the need for a non-continental liquid fuel subcategory for island units that have limited fuel options and other unique circumstances; and the appropriate subcategory for mixed fuel units. The comments and EPA responses are provided below.

1. Limited Use Subcategory

Comment: Industry representatives and State and local governments argued that limited use units are significantly different from steady-state units and requested that they have their own subcategory. Commenters requested various thresholds for a limited-use subcategory including 10 percent annual capacity factor or 1,000 hours of operation per year. Several commenters stated that due to their function, limited use boilers spend a larger percentage of time in startup, shutdown, or other reduced-efficiency operating conditions than either base-loaded or load-following (continuously operated) units. Operating more frequently in these conditions makes emissions profiles of limited use units very different from sources which operate in more efficient steady-state modes. Based on this, commenters claimed it would be technically infeasible for limited-use units to meet the proposed emission limits.

In addition to technical reasoning, commenters also submitted requests for a limited-use subcategory on the basis of regulatory precedent, citing the 2010 RICE MACT and 2004 vacated Boiler MACT. Several commenters requested a subcategory and work practices similar to those in the Stationary RICE NESHAP. Several other commenters also stated that the subcategory was warranted because it was included in the previous Boiler MACT rule. These commenters argued that EPA had not provided any justification for eliminating the subcategory in the proposed rule. Some of these commenters also stated that the recordkeeping requirements that were proposed in Section 63.7555(d)(3) for limited-use boilers and process heaters should be the only requirement for these units.

The majority of commenters that requested a limited use subcategory also requested for EPA to adopt a work practice standard for limited use units and not subject the subcategory to emissions testing or monitoring. Commenters argued that EPA has acknowledged that there is no proven control technology for organic HAP emissions from limited use units. Limited use units, such as emergency and backup boilers, cannot be tested effectively due to their limited operating schedules. Based on existing test methods, which require a unit to operate in a steady state, limited use units would have to operate for the sole purpose of emissions testing. One commenter claimed that the proposed rule performance testing would require, not including startup and stabilization, operating at least 15 additional hours of per year, or 24 hours per year if testing for all pollutants is required. Commenters also noted that because the operation of these units is neither predictable nor routine over a 30 day period, back-up boilers would not benefit from 30-day emissions averaging. Commenters argued that establishing numerical standards for limited use units is contrary to the goals of the CAA and will lead to creating emissions for the sole purpose of demonstrating compliance.

Many commenters also mentioned the economic impacts of a numerical limit on limited-use units and requested work practice standards. Commenters stated that it would not be cost effective to install controls on units that operate at 10 percent capacity or less annually. They claimed that the additional controls would produce minimal emission reductions and would result in the shutdown of limited-use units.

Several commenters claimed that the current distinction between natural gas and oil-fired limited-use units is unnecessary, and that additional requirements for oil-fired units do not produce environmental benefits. Commenters recommended that EPA create a separate subcategory for limited use, oil-fired boilers and suggest that the work practice standard proposed for gas-fired boilers be applied in lieu of emissions standards for these units. Other commenters stated that the limited use subcategory should include new/reconstructed limited use units as well as existing units for all fuel categories. One commenter recommended a tiered approach and stated that for very limited use boilers, EPA should establish a standard with no additional controls or requirements, other than monitoring annual hours of operation. They defined very limited use as <500 hours of operation per year.

Response: EPA agrees that a subcategory for limited use units is appropriate for many of the reasons stated by the commenters. The fact that the nature of these units is such that they operate for unpredictable periods of time, limited hours, and at less than full load in many cases has lead EPA to determine that limited use units are a unique class of unit based on the unique way in which they are used and EPA is including a subcategory for these units in the final rule. The unpredictable operation of this class of units makes emission testing for the suite of pollutants being regulated impracticable. In order to test the units, they would need to be operated specifically to conduct the emissions testing because the nature and duration of their use does not allow for the required emissions testing. As commenters noted, such testing and operation of the unit when it is not needed is also economically impracticable, and would lead to increased emissions and combustion of fuel that would not otherwise be combusted. Therefore, we are regulating these units with a work practice standard that requires a biennial tune-up, which will limit HAP by ensuring that these units operate at peak efficiency during the limited hours that they do operate.

2. Combination Grate/Suspension Firing

Comment: Several commenters requested EPA further subcategorize boilers and process heaters according to combustor design. Three industry and collective trade group representatives requested EPA consider adding a bagasse boiler subcategory. These commenters claimed that bagasse boilers are different from other biomass boilers based on both fuel type and boiler design. The commenter suggested four factors EPA should consider when establishing similar sources or subcategories: (1) Do the units in the category have comparable emissions; (2) are the units structurally similar in design; (3) are the units structurally similar in size; and, (4) are the units capable of installing the same control technology. The commenter elaborated on the fuel density and moisture of bagasse fuel and highlights the unique combustor design needed to heat and evaporate the moisture from the fuel using a combination of suspension and grate firing. Several commenters requested that EPA set separate subcategories for organic HAP (or CO) and for metal HAP and PM for bagasse boilers (between 48 to 55 percent moisture), suspension burners designed to burn dry biomass (defined as less than 30 percent moisture), suspension burners designed to burn wet biomass (greater than 30 percent moisture), and Dutch ovens.

One commenter also requested that the regulatory definition of bagasse boiler be altered to take into account that bagasse boilers are hybrid suspension and grate/floor-fired boilers uniquely designed to dry and burn bagasse. The commenter goes on to explain that the majority of drying and combustion take place in suspension and the combustion is completed on the grate or floor. The boilers are designed to have high heat release rates and high excess air rates which are to evaporate high fuel moisture content and this design impacts CO, PM, and organic HAP formation. Under the proposal, most bagasse-fired boilers would be categorized as “suspension burners/dutch ovens designed to burn biomass.” However, the commenter claimed that the CO limit for this subcategory was driven largely by emissions data from units which fire dry biomass (*i.e.,* less than 20 to 30 percent moisture fuel) that do not need to undergo this initial drying process, since the fuel is already dry enough to combust. The commenter elaborated that emissions of organic HAP and PM from these dry biomass suspension boilers are much different than boilers that must use a combination of suspension firing and grate firing in order to achieve complete combustion of a wet fuel such as bagasse.

One commenter went on the say that EPA has inappropriately subcategorized suspension burners/dutch ovens designed to burn biomass as a single subcategory. Hybrid suspension/grate-floor burners are designed such that the wet fuel first undergoes drying and then combustion in suspension within the furnace, with any remaining unburned fuel falling onto the grate to complete combustion. Another commenter also provided technical design elements to highlight the differences between dutch ovens, suspension burners, and the above mentioned hybrid suspension grate burners. This commenter indicated that dutch ovens have two chambers. Solid fuel is dropped down into a refractory lined chamber where drying and gasification take place in the fuel pile. Gases pass over a wall into the second chamber where combustion is completed. Dutch ovens are capable of burning high moisture fuels such as bark, but have low thermal efficiency and are unable to respond rapidly to changes in steam demand. On the contrary, suspension burners combust fine, dry fuels such as sawdust and sander dust in suspension. Rapid changes in combustion rate are possible with this firing method. This commenter added that some dutch oven units located at particleboard, hardboard, and medium density fiberboard plants were misclassified and there are less than 30 true dry-fired suspension burners in operation, and only a small handful of true dutch oven boilers.

Response: EPA agrees that for combustion-related pollutants (used as a surrogate for organic HAP emissions), the design differences for hybrid suspension grate boilers (also referred to as comination suspension/grate boilers) are significant, and that combustion conditions in these types of units are not similar to those in dutch ovens or true suspension burners that combust fine, dry fuels. Therefore, EPA has added a hybrid suspension grate boiler subcategory for CO and dioxin/furan emissions. However, the differences discussed by the commenters with respect to PM are less indicative of the design of the boiler and more indicative of the types of air pollution controls that are used. In keeping with the subcategorization approach being used for this final rule, these units, and all other solid fuel units, will be included in a subcategory for units combusting solid fuels for PM, Hg, and HCl.

3. Non-Continental Units

Comment: Commenters from affected island refineries and trade groups representing the petroleum and refining sectors requested additional fuel oil burning flexibility in this final rule and stated that work practice standards are more appropriate for fuel oil burning at refineries and other remote locations without access to natural gas.

Commenters also submitted technical issues justifying the creation of a non-continental or remote location subcategory. One commenter stated that most oil combustion in the petroleum sector is in locations that are islands or in more remote parts of the United States. Island and remote facilities cannot physically access natural gas pipelines, making burning liquid fuels unavoidable. The option of crude oil shipments would be impractical because the ships are limited by size and what is manageable by load/discharge ports. The commenter also claims that in the time it would take a crude ship to arrive, the refinery would have produced the amount of crude in the shipment. Further, while some units at a facility are designed to burn refinery fuel gas, the fuel gas produced at a refinery is less than the energy required to operate the refinery. These non-continental facilities are also limited to the fuel quality provided by their nearby crude slate used in the refining process. That commenter goes on to say that these refineries produce their fuel, the HAP metals content of the fuel used (particularly residual fuel oil) is a direct result of the crude slate used on site. The commenter submitted trace metals from various crudes to show that the content varies substantially between crude oils being used on site.

Another commenter provided the following distinctions for non-continental units: A striking example of fuel system differences for non-continental units is daily variation in fuel gas production due to ambient temperature fluctuations between night and mid-day or resulting from tropical rainfall events, coupled with fin fan cooling systems that are used because of the lack of fresh water available in an island without freshwater lakes or streams. The fuel system experiences a large daily variation in refinery fuel gas due to changes in ambient air temperature. These changes occur as a day-night swing in the refinery or any time there is a significant rain storm. As the ambient air temperature decreases, the amount of propane, butane and heavier molecules in the fuel gas decreases, as those compounds condense out. This results in a change in volume and composition (energy content) of the refinery fuel gas produced which, in the case of rainfall events, occurs very quickly and unpredictably. This temperature variation occurs more frequently than at a mainland refinery because: The method of cooling on gas compressors and distillation column overheads systems is ambient air fin fan coolers (water with cooling towers is not used like a stateside refinery because fresh water is not available other than by desalination); the refinery fuel gas system contains miles of aboveground piping (long lines are affected by rain and weather conditions); refinery fuel gas contains more propane and butane than would natural gas from a pipeline (which condense at closer to ambient temperatures than methane or ethane); the make-up fuel system for the refinery is not a natural gas pipeline as at a stateside refinery. A natural gas pipeline can handle changes in refinery fuel gas produced because natural gas delivery systems are usually large enough to handle changes. A temperature change of 10 to 15 degrees or a rain storm that quickly wets the air fin fans/piping will change the volume and composition (energy content) of the refinery fuel gas produced and also impacts CO emissions.

In addition to the technical limitations described above, one commenter cited other EPA air regulations that have provided separate standards or subcategories for non-continental units. For example, 40 CFR part 60 subparts Db and KKKK include separate standards for "non-continental" units and the 2010 CISWI proposal had a subcategory for smaller remote facilities because of inherent design and operating constraints.

Another commenter mentions that the inability to obtain natural gas removes the option of being able to burn only gaseous fuels as a compliance strategy and burning fuel oil as a supplemental fuel makes complying with this proposed MACT unfairly onerous.

Response: EPA agrees that the unique considerations faced by non-continental refineries warrant a separate subcategory for these units. However, data were only provided for CO and Hg, and, in the absence of data for the other pollutants, EPA is adopting the same limits that were developed for liquid units, because liquid units are the most similar units for which data are available. EPA assumed that while the commenter focused on changes in refinery gas, that the commenters concern was with liquid fuel-fired units whose performance is impacted by the co-firing of refinery gas. Regardless, it is clear that the unique design of this type of unit warrants a separate subcategory because design constraints would not enable the sources to meet the same standards, particularly for CO, as stateside units.

4. Combination Fuel Units

Comment: Several industries and industry representatives in addition to some State and local governments argued that combination fuel units are significantly different from units in single fuel subcategories. These commenters focused on three types of combination fuel units. The first, which the majority of comments focused on, was biomass and coal co-fired units. Commenters stated that classifying units that burned 90 percent biomass in the coal subcategory if it fired at least 10 percent heat input coal penalizes and discourages the use of biomass. One commenter claimed that they were unaware of any available control technology with the capability of reducing emissions from its biomass-fired boilers from their current levels to the level proposed for the coal stoker subcategory. Commenters stated that in order to meet the organic HAP limits for coal, they would have to switch from biomass to more coal or abandon co-firing projects. According to the commenter this result was contrary to state Renewable Portfolio Standards and general national renewable energy policy.

The second type of combination unit commenters discussed was units that co-fire gas and liquid fuels. Many commenters argued that combination oil and gas fired units are of a completely different design than EPA contemplated in setting its standards and cannot be fairly included in the same subcategory with other dedicated gas or oil fired units. Commenters elaborated that the main design difference was due to combustion techniques which require the heater/boiler firebox configuration to compromise between the needs of oil fuel and gas fuel, making it impossible to maximize combustion efficiency or minimize NO_X emissions. Commenters also noted that these units were not considered in development of the MACT standards, and claimed that they are well known in the burner industry and referenced in standard literature.

The third type of combination unit, one commenter mentioned, was a subcategory for units co-firing biomass with any solid fuel. Commenters claimed that by failing to recognize the wide verity of fuel inputs and thus the variation in fuel quality (i.e., BTU and moisture content) and emissions, EPA was penalizing facilities that use multiple fuel streams. The commenter went on to request that EPA establish emission limits that reflect the variation in fuels and fuel quality in these combination units.

Several commenters disagreed with the EPA statement that boilers are designed to burn only one fuel and that unit will encounter operational problems if another fuel type is fired at more than 10 percent heat input. Commenters stated that some boilers are specifically designed to burn a combination of fuels, and to burn them in varying quantities. Commenters elaborated that such boilers are not able to reach full load on any single fuel and that EPA has incorrectly presumed that all boilers are designed based on a primary fuel. Some commenters identified that many of the boilers used as the basis of the proposed MACT floor emission limits co-fire different fuel types. One commenter stated that if most units are designed to burn a primary fuel and will encounter problems if the 10 percent threshold is exceeded, then EPA has proposed MACT standards that will apply to boilers that by their nature are "encountering problems" due to their fuel mix. The commenter requested that EPA addresses this inconsistency.

Many commenters noted that emissions profiles vary with the fuel which made it very difficult to establish a typical emissions profile. Commenters also explained that combination fuel boilers must often adapt to process steam demands and thus experience frequent load swings and fuel input adjustments that cause significant variation in CO emission levels. Commenters also mentioned that control compatibility should be considered for multi-fuel boilers because they have inherently different control needs depending on the fuels being fired. Commenters went on to say that current limits are based on control equipment that is optimized for one HAP or fuel but the affect of other HAP and fuels or even another control would result in unknown performance and compatibility with other fuel types.

Several commenters also had concerns regarding enforcement and compliance of combination fuel units. One commenter requested that EPA more specifically address the "enforceability" of the "designed to burn" classification and more clearly consider the implications of the multi-fuel boiler operation on testing considerations. Another commenter stated that expressing limits as applicable to units "designed to burn" certain fuels was problematic and should be changed to "permitted to burn" because a State permit could limit the type of fuels combusted at a unit that may have originally been designed to burn other fuel types. Other commenters claimed that the fuel subcategory should be determined by the actual quantity of fuel burned not what the unit is designed to burn. Some questions that commenters requested clarification on were: If compliance tests would be required under different fuel firing conditions, can units with CEMS switch limits depending on what fuel is being combusted, if "designed to combust" is not maintained would actual fuel burned or fuel the unit is permitted to burn determine the subcategory, what would the annual performance test be if in the middle of the year a unit goes from having burned only one type of fuel to only another type the rest of the year.

Several solutions were suggested for addressing combination boilers. Some commenters requested that combination boilers have their own subcategory. Several other industry commenters suggested that EPA modify the subcategory definitions and applicability so that combination fuel units burning more than 10 percent coal with biomass would be regulated under the coal subcategory for fuel-based HAP and units burning more than 10 percent biomass with coal would be regulated under the biomass subcategory for combustion-based HAP. A more general solution proposed, for all types of combination fuel units, was that if a facility combusts more than one fuel type, it must meet the lowest applicable emission limit for all of the fuel types actually burned. Some commenters also requested the development of a formula based approach similar to that of the boiler NSPS SO_2 limits that considers the mix of fuel fired rather than assuming one fuel dictates the emission limitations.

Some commenters were concerned that determination of MACT floor limits should be based only on data obtained while firing 100 percent of the affected fuel category and recommended that EPA either exclude all test runs where a unit was co-firing or adjust the data accordingly to remove the co-firing bias.

Response: In response to the variety of comments regarding combination fuel boilers, EPA has revised the subcategories in order to simplify implementation, improve the flexibility of units in establishing and changing fuel mixtures, promote combustion of cleaner fuels, and provide MACT standards that are enforceable and consistent with the requirements of section 112. For the combination liquid and gas-fired units, while the commenters provided some insights on these units, the data available to EPA regarding any distinctions between these units and units designed to burn liquid only were insufficient to provide a justification for changing the approach for these units. For combined fuel units that combust solid fuels, due to the many potential combinations and percentages of solid fuels that are or can be combusted, for the fuel-based pollutants, EPA selected the option of combining the subcategories for solid fuels into a single solid fuel subcategory. For the fuel-based pollutants, this alleviates the concerns regarding changes in fuel mixtures, promotion of combustion of dirtier fuels, and the implementation and compliance concerns. For combustion-based pollutants (CO and dioxin/furan), we maintained the proposed subcategories and added a few additional subcategories, as discussed elsewhere in this preamble, based on public comment. One change we are finalizing is that to determine the appropriate subcategory, instead of considering whether the unit is designed to combust at least 10 percent coal as the first step (as proposed), the first step in determining the appropriate subcategory is to consider the percentage of biomass that is combusted in the unit.

The subcategories for the combustion-based pollutants are now determined in the following manner. If your new or existing boiler or process heater burns at least 10 percent biomass on an annual average heat input basis, the unit is in one of the biomass subcategories. If your new or existing boiler or process heater burns at least 10 percent coal and less than 10 percent biomass, on an annual average heat input basis, the unit is in one of the coal subcategories. If your facility is located in the continental United States and your new or existing boiler or process heater burns at least 10 percent liquid fuel (such as distillate oil, residual oil) and less than 10 percent coal and less than 10 percent biomass, on an annual average heat input basis, your unit is in the liquid subcategory. If your non-continental new or existing boiler or process heater burns at least 10 percent liquid fuel (such as distillate oil, residual oil) and less than 10 percent coal and less than 10 percent biomass, on an annual average heat input basis, your unit is in the non-continental liquid subcategory. Finally, for the combustion-based pollutants, if your unit combusts gaseous fuel that does not qualify as a “Gas 1” fuel, your unit is in the Gas 2 subcategory.

D. Work Practices

1. Gas 1 Work Practices

Comment: Several industry and industry trade group commenters expressed general support for the adoption of work practice standards for natural gas and refinery gas (Gas 1) fired boilers and process heaters. Many of these commenters stated that work practice standards will minimize HAP emissions in a cost effective manner.

Commenters, including industry representatives and one government agency, submitted several technical justifications that supported the proposed work practice standards for natural gas and refinery gas units. Many of these commenters stated that Gas 1 units contribute a negligible amount of the total emissions from the source category. One commenter stated that based on a review of air permits issued for natural gas-fired units over the last 10 years no HAP emissions were identified at rates which required the State to set emission limits. Further, many commenters indicated that no currently-available control technology or technique has been indentified to achieve numeric limits for natural gas units. Others went on to argue that tune-ups actually represent the only “floor” technology currently in use at boilers and process heaters in the Gas 1 subcategory. One commenter stated that design characteristics of these units, and hence the emissions-reduction potentials of annual tune-ups, vary widely and no single emission rate or even percentage of emission reduction could be translated into a numerical limit.

Several commenters argued that work practice standards were justified based on the technical infeasibility of emissions testing and the accuracy of testing results from gas units. These commenters stated that most of the emission test data were close to detection limits or in some cases indistinguishable from ambient air near the lowest detect levels, thus preventing the limits from being enforced or reliably measured. Others argued that the application of EPA test methods to measure emissions from natural gas units results in unreliable data given that the emissions are low and below what the test methods can detect, causing repeat tests or significantly lengthening the periods for the tests, which in turn increase the cost of testing.

On the contrary, one of the environmental advocacy group commenters stated that EPA exempted natural gas-fired units from CO limits without any discussion or analysis. This commenter argued that nothing in the rulemaking docket showed that measurement would be technically infeasible and identified CO emission test results from over 160 natural gas-fired units in the NACAA database. Further, the commenter suggested that federal, State and local authorities have routinely required CO to be measured at gas fired units since CO is a criteria pollutant under the CAA.

In addition to technical reasoning, many industry and industry representative commenters also supported the adoption of work practice standards on the basis of legal precedent and authority under the CAA. Commenters stated that EPA derives its authority to use work practices in lieu of numeric emission limitations from two different statutory provisions: The narrowly construed provisions of 112(h) and the broad authority under 112(d) as defined in section 302(k). Additionally, one commenter stated that work practice standards for Gas 1 units are consistent with the D.C. Circuit’s opinion in *Sierra Club* v. *EPA* on the Brick MACT standard, which provided guidance on the criteria EPA must meet to justify the application of section 112(h) work practices, only if measuring emission levels is technologically or economically impracticable.

Many commenters also cited economic justifications supporting the proposed work practices for Gas 1 units. These comments included claims that work practice standards avoid economic harm to the manufacturing sector, and they added that the cost to control each unit would be extremely burdensome with minimal benefits to the environment. These commenters suggested that any type of control beyond a tune-up would be a beyond-the-floor option and the complex controls needed to achieve such low emission levels would fail the cost-benefit determination needed to justify a beyond-the-floor option.

On the contrary, two environmental advocacy groups submitted comments opposing EPA’s rationale for exempting Gas 1 units from CO limits on the basis of cost. The commenters argued that the only economic defense of work practice standards that would be justified was if economic limitations rendered the measurement of emissions “impracticable.” Further, the commenters suggested that many of these Gas 1 units would require more than a tune-up to achieve comparable reductions to those estimated if a numeric MACT floor standard was required.

Another commenter representing the coal industry also disagreed with EPA’s use of a public policy rationale to justify a work practice for Gas 1 units instead of demonstrating that a work practice meets the requirements under section 112(h). The commenter argued that cost considerations were not relevant in a MACT floor analysis and they noted that the per unit costs of complying with MACT standards for gas units are lower than the cost for coal units.

Many commenters from industry, industry trade groups, universities, and State agencies agreed that emission limits would provide a disincentive to operate or switch to natural gas and refinery gas fired units. Commenters claimed that if limits for Gas 1 were adopted, units would switch from natural gas to electric systems powered by coal. Commenters stated that EPA correctly concluded that imposing emission limitations on gas-fired boilers would create a disincentive for switching to gas from oil, coal, or biomass as a control technique and would create an incentive for facilities to switch away from gas to other fuels.

A commenter from a private coal company indicated that EPA’s concerns that establishing a MACT floor limit for Gas 1 units would incentivize fuel switching to coal or other fuels contradict EPA’s rejection of fuel switching as a MACT floor alternative. The commenter added that if EPA rejected fuel switching because of its costliness and lack of a net emissions benefit, EPA should want to discourage coal units from converting to natural gas rather than promoting fuel switching to natural gas. This commenter also claimed that establishing a work practice standard for only Gas 1 units discriminated in favor of the use of natural gas and against the use of coal. The commenter argued that such a policy rationale invokes considerations that are not relevant in setting MACT floor standards and suggested that such a rationale is in violation of both CAA and the Equal Protection Clause of the Constitution. This commenter added that the only relevant statutory factor under 112(h) to help EPA determine where to apply a work practice standard was whether the hazardous air pollutant cannot be emitted through a conveyance designed and constructed to emit or capture that pollutant, whether the use of such a conveyance would be inconsistent with law, or whether the application of measurement methodology is not practicable due to technological and economic limitations.

Response: EPA has determined that it is not feasible to prescribe numerical emissions standards for Gas 1 units because the application of measurement methodology is not practicable due to technological and economic limitations. Therefore, EPA is finalizing the work practice standards for Gas 1 units. The commenters correctly point out that the measured emissions from these units are routinely below the detection limits of EPA test methods, and, as such, EPA considers it impracticable to reliably measure emissions from these units. Even CO, which commenters correctly point out was tested at many natural gas and refinery gas-fired units, was below the level EPA considers to be a reliable measurement for more than 80 percent of the test runs that were conducted on Gas 1 units. The case for other pollutants is even more compelling as the majority of measurements are so low as to cast doubt on the true levels of emissions that were measured during the tests. Of the 48 test runs for HCl, 98 percent were below three times the maximum reported measurement detection level; similarly, 100 percent of the Hg runs, and 45 percent of the PM data were below three times the maximum reported measurement detection level. It is unusual to see numbers near the detection limit for PM since the “detection” involves a comparatively simple (compared to other test methods) weighing procedure, and the overall result indicates that the emissions are very close to zero. All of the dioxin tests had multiple non-detect isomers. Overall, the available test methods are greatly challenged, to the point of providing results that are questionable for all of the pollutants, when testing natural gas units. Because of these technological limitations that render it impracticable to measure emissions from Gas 1 units, EPA is also unable to establish the actual performance of the best performers as well as sources outside of the top performing 12 percent. The inability to accurately measure emissions from Gas 1 units and the related economic impracticability associated with measuring levels that are so low that even carefully conducted tests do not accurately measure emissions warrant setting a work practice standard under CAA section 112(h). EPA is establishing a requirement to implement a tune-up program as described in Section III.D of this preamble. As noted by many commenters, the tune-up program is an effective HAP emissions limitation technology. The requirement of an annual tune-up will allow these units to continue to combust the cleanest fuels available for boilers while minimizing emissions to the same degree that is consistent with the operating practices of the best performing units in the subcategory.

2. Combining Gas 1 and Gas 2 Subcategories

Comment: Several commenters requested consolidation of the Gas 1 and Gas 2 subcategories into a single gas-fired subcategory. The majority of commenters supported this concept by suggesting that there is very little difference between emissions from the top performing sources in each of the two gas subcategories. One commenter specifically argued that in most cases the mean emission levels for Gas 2 fuels are within range and confidence intervals for individual Gas 1 fuels and that the differences in fuel characteristics do not have a first order impact on HAP emissions. The commenter reported on communications with a facility in the database firing a heavy recycle liquid and natural gas fuel combination, which indicated that this unit is a liquid fuel boiler and they provided an analysis of the dataset without this heavy recycle data where the confidence intervals for the remaining landfill gas, biogas/natural gas, and coke oven gas all overlap that for Gas 1 fuels. The commenter also claimed that if 12 outliers from two process gas facilities are eliminated, the remaining 232 of 244 CO data points within Gas 2 fuel group compare favorably with, even lower than, CO levels from Gas 1 fuels. Another commenter stated that pilot scale and field data studies have concluded that emissions of organic HAP from gaseous fuels are not significantly affected by fuel type.

In lieu of a single gas subcategory, several of the commenters requested that the Gas 1 subcategory be expanded to include gases similar to natural gas and refinery gas. These commenters argued, much like the commenters advocating for a single gas-fired subcategory, that units fired with process gases generated in chemical plants, pulp and paper plants, iron and steel plants, and similar operations should be included in the Gas 1 subcategory because the emissions data show very little difference in performance. One commenter stated that most of the Gas 2 fuels, including all 9 of the data points used in the proposed floor calculations, are from chemical plants. The commenter added that at a minimum, chemical plant process gas should be grouped with refinery gas in Gas 1 and a new floor made for Gas 2. One commenter noted that EPA did not gather information on composition or heating value in the Phase 1 ICR survey to justify placing chemical process gases in a separate subcategory from natural gas and refinery gas. Another commenter submitted combustion properties of refinery gas and petrochemical gas in order to argue that they are very similar in composition and should be categorized with natural gas in the Gas 1 category.

In order to accomplish this expansion of the Gas 1 subcategory, many commenters also addressed the definition of natural gas and refinery gas. One commenter simply stated that all gases derived from hydrocarbon sources should be classified under the Gas 1 subcategory. Another commenter suggested the definition of refinery gas in 40 CFR part 63 subpart CC for the Petroleum Refineries NESHAP should be used in this final rule. The commenter went on to say that such gases from petrochemical processes have similar compositions to those stated in the Subpart CC definition (e.g. methane, hydrogen, light hydrocarbons, and other components) that are used as fuel in boilers and process heaters and thus should be subcategorized as Gas 1. One commenter stated that the definition of natural gas should be consistent across federal air regulations and suggested that the definition of natural gas should be edited to be consistent with the definition provided in 40 CFR Part 60 Subpart Db. Another commenter requested that the definition of Gas 1 include any boiler or process heater burning at least 90 percent natural gas, refinery gas, or process off-gases with metals and sulfur content equal or less than those in natural gas.

Many other commenters argued that in general the definition of natural gas needs to be broadened to account for non-geological origins of natural gas such as landfill gas, biogas, and synthetic gas in order to promote the use of these renewable fuels. This commenter went on to state that the Gas 1 subcategory excludes biogas and process off gases that have no metals and very comparable combustion characteristics to that of natural gas or refinery gas. One commenter argued that landfill gas (LFG) should be included in Gas 1 with the work practice approach because placing it in the Gas 2 subcategory conflicts with EPA Landfill Methane Outreach Program goals. The commenter goes on to say that there is no assurance that all limits can be achieved with control technologies and installation of controls will be prohibitively expensive and thus LFG projects will be stopped or replaced with natural gas. A few commenters suggested that EPA did not have enough data on combustion of anaerobic digester gas to differentiate it from natural gas. One commenter requested confirmation that biogas under the proposed rule would be subject to Gas 2 emission limits. Another commenter requested that EPA separate and clearly define gaseous fuels derived from biomass and noted that depending on the source these fuels can contain chlorine or Hg and constituents that lead to the formation of dioxins and furans. With respect to syngas, one commenter suggested that EPA adopt a definition similar to that used in the 40 CFR part 60 subpart YYYY standards for stationary combustion turbines. The commenter noted that if the purity of syngas was a concern, a solution would be to require the syngas to meet minimum specifications in part 261 of the hazardous waste regulations. Another commenter requested that Integrated Gas Combined Cycle units that use a gasifier to convert coal to gas and remove impurities before combustion be classified under the Gas 1 subcategory.

Three commenters specifically argued for the inclusion of propane fired boilers within the Gas 1 subcategory. One commenter stated that if propane meets the specifications of ASTM D1835–03a or other specification types like the Gas Processors Association Standard 2140–92 it should be included within the Gas 1 definition. Another commenter requested clarification that boilers firing liquefied petroleum gas (LPG) or propane-derived synthetic natural gas (SNG) as a backup fuel are still classified as Gas 1 boilers. The commenter argued that propane or LPG is mixed with air to make SNG and should be considered natural gas for the purposes of this final rule.

Several commenters specifically requested that hydrogen plant tail gas or similar process gases that are derived from natural gas be included in the Gas 1 subcategory. Commenters argued that hydrogen fuels do not contain HAP and subcategorizing the fuel as Gas 2 subjects the units to limits that would achieve no further reduction of HAP but require extensive performance testing, recordkeeping, fuel analysis and monitoring requirements. One commenter submitted historical facility data from a unit firing byproduct hydrogen and the commenter claimed that the fuel is cleaner burning than natural gas. One commenter suggested an 8 percent by volume minimum hydrogen content in hydrogen-fueled process gases as a criterion for consideration as a Gas 1 fuel. The commenter mentioned that this percentage is based on a 1998 EPA document that established a minimum hydrogen content by volume for non-assisted flare combustion efficiency.

If a separate Gas 2 subcategory remains in the rule, many other commenters requested that work practices be extended to the Gas 2 subcategory based on the claim that gas-fired units, relative to units firing other fuels, have the lowest emissions and pose the lowest risk of all the subcategories. Thus, the use of gas should be encouraged rather than discouraged. Some commenters argued that as a consequence of establishing limits for Gas 2 fuels, some plant sites currently designed to use Gas 2 streams for energy efficient operations will be forced to dispose of process off-gases in other types of combustion sources such as flares. The commenters added that such disposal would result in essentially the same emissions from combustion of the Gas 2 stream using a flare (as opposed to combusting the fuel in a boiler) and additional emissions from consumption of natural gas that would be used in lieu of the Gas 2 fuel. Overall, the standard as proposed for Gas 2 units would result in increased emissions of all pollutants and lower fuel efficiency.

Response: EPA has determined that to the extent that process gases are comparable to natural gas and refinery gas, combustion of those gases in boilers and process heaters should be subject to the same standards as combustion of natural gas and refinery gas. Boilers that combust other gaseous fuels that have comparable emissions levels to Gas 1 units are similar in class and type to Gas 1 units because they share common design, operation, and emissions characteristics. Therefore, we are providing a mechanism by which units that combust gaseous fuels other than natural gas and refinery gas can demonstrate that they are similar to Gas 1 units and will therefore be subject to the standards for Gas 1 units. EPA originally examined the possibility of basing such a demonstration on levels of mercury and chlorine content in the gases, but no information was available regarding the chlorine content of natural gas or refinery gas, and no proven test methods were identified to quantify chlorine content of natural gas. Therefore, EPA is requiring a demonstration that other gases have levels of H_2S and Hg that are no higher than those found in Gas 1 units. Natural gas purity is commonly defined considering the sulfur content of the gas, in the form of H_2S. Sweet natural gas, which is considered pipeline quality gas, contains no more than 4 ppmv H_2S. Information on Hg levels typical of natural gas was available through literature, and domestic natural gas Hg concentrations range up to about 40 micrograms per cubic meter. Using H_2S and Hg concentration as parameters for establishing equivalent contamination levels to natural gas, EPA is providing a fuel specification that can be used by facilities to qualify Gas 2 units for the Gas 1 standards. The fuel specification would also allow facilities to perform pre-combustion gas cleanup in order to qualify Gas 2 units for the Gas 1 standards. Boilers using process gases that do not meet the fuel specification and are not processed to meet the contaminant levels must meet the emissions limits for Gas 2 units.

3. Dioxin/Furan Emission Limits or Work Practices

Comment: Many commenters disagreed with the proposed dioxin/furan emission limits. Some commenters noted that a large majority of the dioxin/furan test data are non-detect values. As such, under section 112(h)(2)(b) of the CAA, the commenters noted that EPA has the authority to establish work practice standards when "the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations." Other commenters stated that dioxin/furan formation in industrial boilers is not well understood and it would not be possible to duplicate the emissions from the facilities tested during the Phase II ICR that were used as the basis of the limit. One commenter indicated they will undergo preliminary research on the dioxin/furan removal efficiency of ESP and scrubbers, but much additional research is needed. Several commenters also added that there are no demonstrated technologies that would allow the units to reduce their emissions below the limit. Furthermore, control device vendors commented that they would not be able to guarantee their equipment will be able to control dioxin/furan for the affected boilers and process heaters due to lack of practical experience on boilers and process heaters. They also noted that most industry experience in controlling dioxin/furan is for waste-to-energy plants where concentrations of these pollutants are much higher than the reported Phase II ICR testing results.

Many commenters believe EPA is not authorized to regulate the entire dioxin/furan class as is currently proposed. They noted that in the section 112 HAP list only two compounds are specifically named, dibenzofuran and 1,3,7,8 TCDD, and the MACT floor must be limited to those two and not all 17 congeners. Furthermore, some commenters stated that neither the initial EPA source category list (EPA–450/3–91–030) or the 2004 Boiler MACT rule identified dioxin/furan as a pollutant to be regulated.

Some commenters stated that regulating dioxin/furan emissions from these boilers and process heaters is not necessary because they are not a significant source of emissions. They noted that dioxin/furan emissions are significantly higher in units that burn chlorinated wastes and only those applicable rules (*e.g.* CISWI and Municipal Waste Combustors) should focus on regulating dioxin/furan. Having a limit in this Boiler MACT would only cause undue burden with minimal environmental impact. Given the uncertainties surrounding dioxin/furan emissions, a few commenters suggested EPA should do a thorough review prior to finalizing limits for this final rule to determine how this source category affects public health. It is suggested that EPA review the following questions: What portions of the annual total dioxin/furan emissions are contributed by this source category; what are the other major sources of dioxin/furan throughout the country; what are the current conditions for dioxin/furan exposure throughout the U.S.; have levels been going down or changing and if so by how much; and, could reductions be achieved more effectively by examining other sources of dioxin/furan?

In lieu of a specific dioxin/furan limit, many commenters suggested that CO should be used as a surrogate and meeting the CO limit would reduce dioxin/furan. While EPA stated in the preamble to the proposed rule that it is not appropriate to use CO as a surrogate, these commenters stated that the precursors to dioxin/furan formation are produced by incomplete combustion and thus dioxin/furan formation itself is indirectly related to the combustion process similar to the other organic HAP CO is currently used as a surrogate for. Another commenter suggested that control of other HAP such as Hg will provide adequate incidental control and reduction of dioxin/furan and the cost of separately monitoring dioxin/furan is not warranted taking into consideration the cost of achieving such emission reductions, energy requirements, and environmental impacts as required by Section 112(d)(2) of the CAA.

On the contrary, another commenter suggested that EPA correctly recognized that dioxin/furan can be formed outside of the combustion unit, not as part of the combustion process, and so sets separate standards for these carcinogens.

Several commenters provided specific comments on a lack of data available for boilers burning bagasse in a combined suspension and grate firing design.

As an alternative to the limits, many commenters offered suggestions for a work practice standard to minimize dioxin/furan emissions. These comments focused on creating boiler-specific plans for implementing good combustion practices along with an operations and maintenance plan. Additionally, boiler operators could maintain a minimum temperature at the outlet of PM control devices to minimize dioxin/furan formation.

Response: In response to the comments that EPA is not authorized to regulate the dioxin/furan class as proposed, the commenters are incorrect. While dibenzofuran and 2,3,7,8 TCDD are two of the HAP listed in section 112, all dioxin and furan compounds are considered to be POM and, as such, EPA has the authority to regulate these compounds under section 112. The risk-related questions suggested by commenters are not applicable to establishment of the MACT floor standards under section 112(d), which are to be based on the average emissions performance of the best performing units for which the Administrator has emissions information. EPA received a number of comments on dioxin and furan emission limits regarding the ability of the test method to measure the typically low levels of emissions that are emitted from boilers and process heaters.

Commenters stated that the emissions were so low that they could not be measured, and therefore work practice standards, rather than emission limits, should be finalized for dioxin/furan for all subcategories. EPA disagrees. While emissions were below detectable levels in many tests for a large portion of the dioxin/furan isomers, virtually every test detected some level of dioxin/furan. Furthermore, some of the emission tests detected most or all isomers at some level. Dioxin/furan emissions can be precisely measured for at least some units in each subcategory except for Gas 1. Therefore, except for the Gas 1 subcategory, which is addressed elsewhere in this preamble, the statutory test for establishment of work practice standards—i.e., that measurement of emissions is impracticable due to technological and economic limitations—is not met.

In order to make sure that the emission limits are set at a level that can be measured, EPA used the “three times MDL” approach (discussed elsewhere in this preamble) as a minimum level at which a dioxin/furan emission limit is set. Rather than finalizing work practice standards, but recognizing that emissions tend to be very low compared to more significant sources of dioxin such as incinerators, EPA’s approach to dioxin requires an initial compliance test to demonstrate that the units meet the dioxin/furan standard, and no additional compliance testing. Following a test demonstrating compliance with the emission limit, provided that the unit’s design is not modified in a manner inconsistent with good combustion practices, the oxygen level must be monitored, and the 12-hour block average must be maintained at or above 90 percent of the level established during the initial compliance test in order to provide an assurance of good combustion. Another important point to mention is that the dioxin/furan test method, EPA Method 23, requires that for compliance purposes, non-detect values should be counted as zero. Therefore, for purposes of compliance, the concern about not being able to meet the standards because of the contribution of non-detect values is moot.

4. Work Practices for Small Units

Comment: Many commenters stated EPA should treat new small units in the same manner as existing small units; for boilers and process heaters with a design capacity less than 10 MMBtu/hr, a work practice standard should be implemented instead of numerical limits. These commenters stated that the same technical and economic conditions under section 112(h) for existing units still held true for new units. New small boilers and process heaters (less than 10 mmBtu/hr) are typically designed like comparable existing units with small diameter stacks, or wall vents and no stack. These vents and small stacks do not allow for accurate application of standard EPA test methods required to demonstrate compliance with emission limits, and larger stacks would decrease the efficiencies of the units. They continued that while there are some savings in adding the controls and monitoring equipment during original construction, those savings were minor in comparison to the cost of the control and monitoring equipment itself. One commenter noted that the annual performance tests are over three times the cost of the boiler. In addition, other commenters stated that the D.C. Circuit has upheld EPA’s discretion to have insignificant emission sources exempt from regulations, and small units meet this condition.

Several of the commenters who supported work practice standards for small units also believed the size threshold should change. A few commenters suggested the size should be lowered to 5 MMBtu/hr, while most contended that the size threshold should be raised to 20, 25, or 30 MMBtu/hr. Those commenters who wanted the threshold raised noted that even boilers as large as 30 MMBtu/hr experience the same economic implications on their facilities. Some commenters also noted that 40 CFR part 60 subpart Dc New Source Performance Standards have work practice standards for units less than 30 MMBtu/hr. One State agency commented that the proposed rule established stringent emission limits for new small units. The commenter argued that a tiered approach should be used which required higher emission limits for new small units.

Conversely, some commenters agreed with EPA's proposed method of making the limits applicable to new small units. They noted that new boilers can be built with stacks appropriate for testing, or can have temporary stack extensions built for testing. One commenter added that it is not uncommon for new small boilers to vent exhaust into existing larger stacks that would allow for testing.

Response: We agree that the design of new and existing small units precludes the use of the suite of test methods required by this final rule. As pointed out by commenters, new small boilers and process heaters (less than 10 mmBtu/hr) are typically designed like comparable existing units with small diameter stacks, or wall vents and no stack. These vents and small stacks do not allow for accurate measurement of emissions using the standard EPA test methods required to demonstrate compliance with emission limits, and larger stacks would decrease the efficiencies of the units. Changes in stack diameters or addition of stacks in lieu of wall vents can impact efficiencies of boilers and can require significant redesign of boiler systems, which imposes significant economic limitations. Therefore, EPA has concluded that work practice standards are appropriate for new and existing small units because the measurement of emissions is impracticable due to technological and economic limitations.

E. New Data/Technical Corrections to Old Data

Comment: Many commenters identified shortcomings in EPA's emissions database, and multiple corrections were submitted to EPA both through the public comment process and through e-mail communication with the ICR Combustion Survey team. Commenters also submitted new data directly to the ICR Combustion Survey Team and through the public comment process.

Response: EPA has incorporated all technical corrections and new data submitted since proposal. The corrections and new data are described in detail in a memorandum in the docket entitled "Handling and Processing of Corrections and New Data in the EPA ICR Databases."

F. Startup, Shutdown, and Malfunction Requirements

Comment: Numerous commenters raised concerns that insufficient data are currently available to establish emission standards for SSM events. Due to inherent limitations with measurement methods/technologies, which often require steady state conditions, emissions testing data and CEMS provide limited insight into SSM events, therefore combustor variability during these periods has been underestimated.

To address these data limitations, several commenters suggested that EPA should collect additional data that represent SSM events within each subcategory. One commenter had specific ideas for data collection including collecting SSM data from CEMS installed at the facilities previously included in the ICR survey and using portable analyzers to evaluate SSM emissions during future compliance testing. Many other commenters suggested that it would be infeasible to collect additional data given the test method limitations and suggested that a compliance work practice alternative be provided during periods of SSM. Commenters suggested that work practices should be site-specific, not be overly prescriptive, with the goal of minimizing the emissions during SSM periods. Other commenters suggested that EPA adopt an alternative to regulating emissions during SSM events and cited 40 CFR part 63 subpart ZZZZ, which states that startup time must be minimized.

Several commenters expressed separate concerns for EPA's treatment of malfunction events. Many commenters suggested that malfunction events should be excluded from emission limits and many submitted alternatives to including these periods. One commenter supported a limited allowance for malfunction periods where EPA defines the term "malfunction" and precisely identifies events requiring an immediate and complete shutdown. Another commenter suggested EPA should require facilities to develop and implement work practice standards to reduce malfunctions and minimize pollutants emitted during these periods. A third commenter asked that EPA replicate California permits which include a specific provision for malfunction.

Many industry commenters recognized that the proposal preamble included a statement indicating that EPA promised to address periods of equipment malfunction by considering other information before enforcing exceedance of operating limits. However, the commenters suggested that this promise does not prevent EPA, a State, or a plaintiff in a citizen suit from determining that an exceedance during a malfunction constitutes a violation. These commenters preferred EPA to develop explicit compliance alternatives for malfunctions in the rule language.

Several commenters contended that EPA failed to recognize the inherent limitations in the technology and operating conditions used to reduce emissions during SSM. One commenter referenced a case *(Portland Cement Ass'n* v. *Ruckelshaus* (D.C. Cir. 1973)) where the court acknowledged that "startup" and "upset" conditions due to plant or emission device malfunction are an inescapable aspect of industrial life and that allowance must be accounted for in the standards. Aside from meeting emission limits, commenters provided examples of other operating parameters that are affected during SSM including: Elevated oxygen levels, air pollution control device operating parameters such as sorbent injection rates or ESP voltage, and fuel feed rates, among others. Commenters also raised concerns that applying limits during startups will require sources to decide between safety and environmental compliance by encouraging sources to try to shorten the startup period. For example, some commenters noted that decreasing the warm-up period could cause metallurgical and refractory stresses on the boiler. One commenter indicated that EPA's proposed rule had unnecessarily disregarded the special circumstance, an affirmative defense, of excess emissions allowed in a September 20, 1999, EPA policy memo about State Implementation Plans (SIP). The commenter added that affirmative defense provisions have recently been approved into several states SIP (e.g., Colorado [71 FR at 8959] and New Mexico [74 FR at 46912]). Both the Colorado SIP and the New Mexico SIP contain an affirmative defense for excess emissions during periods of startup and shutdown.

Response: EPA has considered these comments and has revised this final rule to incorporate a work practice standard for periods of startup and shutdown. Information provided on the amount of time required for startup and shutdown of boilers and process heaters indicates that the application of measurement methodology for these sources using the required procedures, which would require more than 12 continuous hours in startup or shutdown mode to satisfy all of the sample volume requirements in the rule, is impracticable. Upon review of this information, EPA determined that it is not feasible to require stack testing—in particular, to complete the multiple required test runs—during periods of startup and shutdown due to physical limitations and the short duration of startup and shutdown periods. Operating in startup and shutdown mode for sufficient time to conduct the required test runs could result in higher emissions than would otherwise occur. Based on these specific facts for the boilers and process heater source category, EPA has developed a separate standard for these periods, and we are finalizing work practice standards to meet this requirement. The work practice standard requires sources to minimize periods of startup and shutdown following the manufacturer's recommended procedures, if available. If manufacturer's recommended procedures are not available, sources must follow recommended procedures for a unit of similar design for which manufacturer's recommended procedures are available.

Regarding comments on treatment of malfunctions, the discussion of EPA's position on malfunctions in the section of this preamble entitled "What are the requirements during periods of startup, shutdown, and malfunction" provides details related to this response. Essentially, EPA has determined that malfunctions should not be viewed as a distinct operating mode and, therefore, any emissions that occur at such times do not need to be factored into development of CAA section 112(d) standards, which, once promulgated, apply at all times. In the event that a source fails to comply with the applicable CAA section 112(d) standards as a result of a malfunction event, EPA would determine an appropriate response based on, among other things, the good faith efforts of the source to minimize emissions during malfunction periods, including preventative and corrective actions, as well as root cause analyses to ascertain and rectify excess emissions. EPA would also consider whether the source's failure to comply with the CAA section 112(d) standard was, in fact, "sudden, infrequent, not reasonably preventable" and was not instead "caused in part by poor maintenance or careless operation." 40 CFR 63.2 (definition of malfunction).

Finally, EPA recognizes that even equipment that is properly designed and maintained can sometimes fail and that such failure can sometimes cause an exceedance of the relevant emission standard. (*See, e.g.*, State Implementation Plans: Policy Regarding Excessive Emissions During Malfunctions, Startup, and Shutdown (Sept. 20, 1999); Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions (Feb. 15, 1983)). EPA is, therefore, adding to this final rule an affirmative defense, as requested by public comment, to civil penalties for exceedances of numerical emission limits that are caused by malfunctions.

G. Health Based Compliance Alternatives

Comment: In the proposed rule, EPA considered whether it was appropriate to exercise its discretionary authority to establish health-based emission limits (HBEL) under section 112(d)(4) for HCl and other acid gases and proposed not to adopt such limits, citing, among other things, information gaps regarding facility-specific emissions of acid gases, co-located sources of acid gases and their cumulative impacts, potential environmental impacts of acid gases, and the significant co-benefits expected from the adoption of the conventional MACT standard. Comments were received both supporting this position and refuting it. Several commenters suggested legal, regulatory and scientific reasons for why HBEL or health-based compliance alternatives (HBCA) for HCl and Mn might be appropriate for this MACT standard. With respect to legal concerns, industry commenters indicated that section 112(d)(4) of the CAA establishes a mechanism for EPA to exclude facilities from certain pollution control regulations and circumstances when these facilities can demonstrate that emissions do not pose a health risk. Commenters cited a Senate Report that influenced development of 112(d)(4), where Congress recognized that, "For some pollutants a MACT emissions limitation may be far more stringent than is necessary to protect public health and the environment." [Footnote: S. Rep. No. 101–128 (1990) at 171]. Commenters also cited regulatory precedence for addressing HCl as a threshold pollutant, including the Hazardous Waste Combustors and the Chemical Recovery Combustion Sources at Kraft, Soda, Sulfite, and Stand-Alone Semichemical Pulp Mills NESHAP. Commenters requested that EPA incorporate the flexibility afforded by 112(d)(4) and allow sources reasonable means for demonstrating that their respective emissions do not warrant further control. Industry commenters also cited the 2004 vacated Boiler MACT as precedence for HBCA for both HCl and Mn. The commenters contended that EPA failed to explain why the health based emissions limitations it established in the 2004 Boiler MACT and the justification provided for those limitations should now be reversed. The commenters also cited a 2006 court briefing where EPA vigorously defended the HBCA included in the 2004 rule when it was challenged in the D.C. Circuit [Final Brief For Respondent United States Environmental Protection Agency, D.C. Cir. Case No. 04–1385 (Dec. 4, 2006) at 59–65, 69.].

Citizen groups also commented that on August 6, 2010, EPA adopted a NESHAP for Portland Cement plants. In its final rule EPA specifically rejected adoption of risk-based exemptions for HCl and Mn. The commenter argues there are no differences sufficient to warrant a reversal of that decision in the Boiler MACT standard. Citizen groups also raised concerns that health risk information cited by EPA for HCl, hydrogen fluoride, hydrogen cyanide, and Mn does not establish "an ample margin of safety" and, therefore, no health threshold should be established. The commenters believe risk-based exemptions at levels less stringent than the MACT floor are prone to lawsuits that could potentially further delay implementation of the Boiler MACT.

Co-Located Source Issues

Many commenters responded to EPA comment solicitation on how it should "appropriately" simulate all reasonable facility/exposure situations. Commenters contended that boilers can be located among a wide variety of industrial facilities, which makes predicting and assessing all possible mixtures of HCl and other emitted air pollutants difficult. These simulations would require the consideration of emissions from nearby facilities for the almost 15,500 boilers affected by this final rule. Commenters also characterized defining of exposure situations as challenging, for example PM can serve as "carriers" to bring the adhered HAP deep within the lung, where the HAP can interact with the respiratory system directly or be leached off of the particle surface and become available systemically. These commenters argue that the questions posed by the Agency in the preamble to the proposed rule illustrate why the MACT standard setting is and should be the default requirement in the 1990 Clean Air Act, rather than "health-based" standard-setting under section 112(d)(4).

Some commenters disagreed with using a hazard quotient (HQ) approach to establish a risk-based standard because the HQ would not account for potential toxicological interactions. The commenter noted that an HQ approach incorrectly assumes the different acid gases affect health through the same health endpoint, rather than assuming that the gases interact in an additive fashion. This commenter suggested that a hazard index approach, as described in EPA's "Guideline for the Health Risk Assessment of Chemical Mixtures" would be more appropriate.

Industry commenters dispute that emissions from other sources or source categories should be considered when developing an HBCA and they argued that Congress expected EPA to consider the effect of co-located facilities during the 112(f) residual risk program instead of under 112(d). Commenters added that there is no prior EPA precedent for considering co-located facilities from a different source category during the same 112 rulemaking. Commenters also provided examples where co-located sources and source categories are not a concern, such as small municipal utilities that do not operate co-located HAP sources within their fence line and are not located in heavily populated urban areas where other HAP sources are common due to zoning. Representatives of the small municipal utility industry suggested that concerns of co-located HAP sources should not be used to arbitrarily deny health-based relief already approved on a site-specific basis.

Co-Benefits of Controlling HCl and Mn

Several commenters disputed EPA's consideration of non-HAP collateral emissions reductions in setting MACT standards. They contended that EPA's sole support for its "collateral benefits" theory is legislative history—the Senate Report that accompanied Senate Bill 1630 in 1989 and noted that the D.C. Circuit rejected this use of this theory since the Senate Report referred to an earlier version of the statute that was ultimately not enacted. Instead commenters suggested that other components of the CAA, such as the National Ambient Air Quality Standards (NAAQS), are more appropriate avenues for mitigating emissions of criteria pollutants. Some commenters in the biomass industry noted that even if co-benefits of non-HAP were considered relevant to the analysis, the nominal co-benefits of reducing SO_2 emissions from biomass units would be limited due to the low inlet sulfur levels of this fuel.

Several other commenters suggested it is impossible to assess an established health threshold for HCl such that a 112(d)(4) standard could be set without evaluating the collateral benefits of a MACT standard. And, as described in the recently finalized cement kiln MACT rule, setting technology-based standards for HCl will result in significant reductions in the emissions of other pollutants, including SO_2, Hg, and PM. The commenter added that these reductions will provide enormous health and environmental benefits, which would not be experienced if section 112(d)(4) standards had been finalized. These commenters contended that HCl and other dangerous acid gases produced by commercial and industrial boilers pose substantial risks to industrial workers, as well as surrounding communities, and must be limited by the strict conventional MACT standards.

Cost Impacts of HBCA

Several commenters indicated that the current economic climate requires EPA to balance economic and environmental interests and they indicated that HBCA would help target investments into solving true health threats where limits are no more stringent or less stringent than needed to protect public health. Many commenters provided compliance cost savings if an HBCA is included in this final rule. For example, representatives of one industry estimated aggregated capital savings in excess of $100 million just for the small facilities in the pulp & paper sector. Some commenters stressed the importance of an HBCA options for small entities affected by the regulations. Several other commenters suggested that EPA should estimate the costs and environmental effects of the HBCA option compared to a conventional MACT standard in order to make an informed decision on the adoption of an HBCA.

Response: After considering the comments received, some of which supported adoption of an emissions standard under section 112(d)(4) and some of which opposed such a standard, EPA has decided not to adopt an emissions standard based on its authority under section 112(d)(4) in the final rule. EPA first notes that the Agency's authority under section 112(d)(4) is discretionary. That provision states that EPA "may" consider established health thresholds when setting emissions standards under section 112(d). By the use of the term "may," Congress clearly intended to allow EPA to decide not to consider a health threshold even for pollutants which have an established threshold. As explained in the preamble to the proposed rule, it is appropriate for EPA to consider relevant factors when deciding whether to exercise its discretion under section 112(d)4). EPA has considered the public comments received and is not adopting an emissions standard under section 112(d)(4) for the reasons explained below.

First, as explained in the preamble to the proposed rule, EPA continues to believe that the potential cumulative public health and environmental effects of acid gas emissions from boilers and other acid gas sources located near boilers supports the Agency's decision not to exercise its discretion under section 112(d)(4). EPA requested in the preamble to the proposed rule information regarding facility-specific emissions of acid gases from boilers as well as sources which may be co-located with boilers. In particular, information concerning the variation of acid gas emission rates that can be expected from the various subcategories of units was identified as a significant data gap. Additional data were not provided during the comment period, and the data already in hand regarding these emissions are not sufficient to support the development of emissions standards for any of the boilers subcategories under section 112(d) that take into account the health threshold for acid gases, particularly given that the Act requires EPA's consideration of health thresholds under section 112(d)(4) to protect public health with an ample margin of safety. In addition, the concerns expressed by EPA in the proposal regarding the potential environmental impacts and the cumulative impacts of acid gases on public health were not assuaged by the comments received.

EPA also received comments recommending not only that EPA establish emissions standards for acid gases pursuant to section 112(d)(4), but that it do so by excluding specific facilities from complying with emissions limits if the facility demonstrates that its emissions do not pose a health risk. EPA does not believe that a plain reading of the statute supports the establishment of such an approach. While section 112(d)(4) authorizes EPA to consider the level of the health threshold for pollutants which have an established threshold, that threshold may be considered "when establishing emissions standards under [section 112(d).]" Therefore, EPA must still establish emissions standards under section 112(d) even if it chooses to exercise its discretion to consider an established health threshold.

As explained in the preamble to the proposed rule, EPA also considered the co-benefits of setting a conventional MACT standard for HCl. EPA considered the comments received on this issue and continues to believe that the co-benefits are significant and provide an additional basis for the Administrator to conclude that it is not appropriate to exercise her discretion under section 112(d)(4). EPA disagrees with the commenters who stated that it is not appropriate to consider non-HAP benefits in deciding whether to invoke section 112(d)(4). Although MACT standards may directly regulate only HAPs and not criteria pollutants, Congress did recognize, in the legislative history to section 112(d)(4), that MACT standards would have the collateral benefit of controlling criteria pollutants as well and viewed this as an important benefit of the air toxics program. *See* S. Rep. No. 101–228, 101st Cong. 1st sess. at 172. EPA consequently does not accept the argument that it cannot consider reductions of criteria pollutants, for example in determining whether to take or not take certain discretionary actions, such as whether to adopt a risk-based standard under section 112(d)(4). There appears to be no valid reason that, where EPA has discretion in what type of standard to adopt, EPA must ignore controls which further the health and environmental outcomes at which section 112(d) of the Act is fundamentally aimed because such controls not only reduce HAP emissions but emissions of other air pollutants as well.[7] Thus, the issue being addressed is not whether to regulate non-HAP under section 112(d) or whether to consider other air quality benefits in setting section 112(d)(2) standards—neither of which EPA is doing—but rather whether to make the discretionary choice to regulate certain HAP based on the MACT approach and whether EPA must put blinders on and ignore collateral environmental benefits when choosing whether or not to exercise that discretion. EPA knows of no principle in law or common sense that precludes it from doing so.

Finally, EPA is not adopting an HBEL for manganese, as some commenters recommended. EPA did not propose or solicit comment on the adoption of an HBEL for manganese emissions, and since the final rule regulates PM as a surrogate for HAP metals and therefore does not establish a specific emissions limit for manganese, there is no reason to consider whether it would be appropriate to exercise section 112(d)(4) authority for manganese.

H. Biased Data Collection From Phase II Information Collection Request Testing

Comment: Many commenters noted that in selecting units for the Phase II testing, EPA targeted only those units whose data EPA determined it would need to set the MACT floor. The commenters contended that the targeted units were generally better performing units so the proposed limits reflect performance of the best 12 percent of the best rather than performance of the best 12 percent of the entire population as Congress intended. Further, they added that this skewed dataset led to a set of proposed emission limits that are more stringent than would have resulted from a random sampling of all the regulated sources. Several commenters also provided input on how EPA should have designed its Phase II test plan in order to develop a representative dataset. They added that representativeness may be considered as the measure of the degree to which data accurately and precisely represent a characteristic of a population. The commenters identified EPA's approach for selecting Phase II testing sites as a form of judgmental sampling, which EPA defines as the "selection of sampling units on the basis of expert knowledge or professional judgment." These commenters then cited an EPA document (Data Quality Assessment: A Reviewer's Guide, EPA QA/G–9R, p. 11, U.S. EPA 2006) which outlines preferred sampling procedures for emission data. According to this document, probabilistic sampling (random selection) is preferable where EPA wishes to draw quantitative conclusions about the sampled population through statistical inferences. When using judgmental sampling, however, this document stated that "statistical analysis cannot be used to draw conclusions about the target population," and "quantitative statements about the level of confidence in an estimate (such as confidence intervals) cannot be made." Yet the commenters point out that EPA did use the Phase II data to perform statistical analyses and establish a MACT floor emission limit for each subcategory. The commenters added that generally, conclusions drawn from judgmental samples apply only to those individual samples while aggregation of data collected from judgmental samples may result in severe bias due to lack of representativeness and lead to highly erroneous conclusions. Many commenters also suggested methods to mitigate the bias in the Phase II testing. Some commenters suggested that instead of taking the top 12 percent of units with stack test data available, EPA should determine how many units comprise the top 12 percent of a given subcategory and then use data from that many units to compute the floor. The commenters suggested that this approach is warranted because the Phase I ICR data allowed EPA to reliably select the top performers in each subcategory for purposes of collecting the Phase II information. Other commenters suggested that EPA supplement its ICR survey and testing data with other data sources such as fuel records, production records and associated emission factors from AP–42, commercial warranties and guarantees, or other EPA databases such as the National Emission Inventory or Toxics Release Inventory. Other commenters requested that EPA incorporate data from the ICR Phase II testing as long as these data are from a unit that has similar fuel and control device characteristics to the units identified in the top 12 percent.

Response: Section 112 specifies that MACT floors must be based on sources for which emissions information is available to the Administrator. While EPA's Phase II data collection did target units with particular control configurations, these units were identified to fill data gaps, including providing additional information on the effectiveness of the various control technologies that are used to control emissions from boilers and process heaters. EPA disagrees with commenters who recommended that EPA should use data from the number of units that comprise 12 percent of a subcategory to calculate the floor, even where the Agency lacks information for all sources in the subcategory. That approach would be inconsistent with the language of section 112(d)(3), which clearly states that, for existing sources, the MACT floor cannot be less stringent than "the average emission limitation achieved by the best performing 12 percent of the existing sources (for which the Administrator has emissions information)[.]" This is precisely what EPA has done in today's final rule. The commenters' recommended approach would instead base the floors on the average emission limitation achieved by

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[7] EPA notes the support of commenter 2898 in this regard.

all the sources for which EPA has emissions information, rather than that achieved by the best-performing 12 percent, if emissions information is only available for 12 percent of sources. This outcome would contradict the language of the statutory MACT floor provision.

EPA also notes that sources had ample opportunity to perform testing on other units and submit the data to EPA for consideration. EPA informed various industry groups that additional test data would be welcomed, and to the extent that additional data were provided, such data were used in the floor-setting process. Furthermore, the large majority of the proposed emission limits were based on data from both phases of the ICR, with most of the data coming from the phase I ICR, in which EPA requested any existing emissions data, and commenters do not allege any bias associated with the phase I data. The only emission limits that were based primarily on phase II ICR data were the dioxin/furan limits, and for those pollutants, the units were not selected based on any assumptions about their dioxin/furan emissions or the effectiveness of add-on controls. Instead, the units were selected to ensure that data would be available to set floors for the subcategories that EPA was considering at the time of the Phase I ICR.

I. Issues Related to Carbon Monoxide Emission Limits

Comment: Numerous commenters disagreed with EPA's statement that CO emissions do not vary significantly over the operating range of a unit, 75 FR 32029. These commenters provided limited data across the operating range of boilers showing significant variation in CO emissions; the data also support the contention that CO emissions are higher at low load. In addition, commenters note that the degree of variability in emissions is dependent upon a specific unit and its design and operation characteristics, as well as other factors. With the premise that boilers do have variable CO emissions, in order to meet the applicable emission limit, commenters stated that stable boiler operation would be necessary, but that such boiler operation is not always possible. They contend that boiler loads vary constantly and rapidly and such load swings are a normal part of many processes and operations. Factors affecting the load include changes in fuel mix, fuel quantity, and fluctuations in load demand. Quick changes or large swings can also result in spikes which are substantially higher than average emissions. Commenters stated that in addition to daily fluctuations, CO emissions vary depending on broader issues such as business cycles or the time of year. Commenters claimed that even the top performers could not meet the limits due to load fluctuations.

Some commenters provided input from boiler manufacturers and the guarantees that are currently available on the market for CO emissions. These guarantees include provisions that void the guarantee at loads below 25 percent load. Burner and boiler manufacturers state that CO emissions do fluctuate with load and suggest that limits should not be lower than manufacturer guarantees.

Many commenters took issue with the use of stack test data to set the emission limit. Due to the highly variable nature of CO emissions, setting a standard that boilers must meet at all times based on stack test data does not properly characterize boiler emissions. Noting that stack tests are typically conducted at 90 percent of full load, commenters contended that this represents a small and unrepresentative snapshot in time captured during the best operating conditions. Some commenters compared stack test averages to CEMS values showing extreme differences (CEMS data could be >10 times higher), and stated that stack tests do not come close to capturing the long-term variability of CO emissions. Furthermore, commenters stated that some boilers frequently operate at low-fire conditions and that stack tests are not conducted at "representative operation conditions". A few commenters cited the DC Circuit [*Sierra Club* v. *EPA*, 167 F.3d 658, 665 (D.C. Cir. 1999)] and pointed out that stack tests do not capture the level of performance a unit will achieve "under the most adverse circumstances which can reasonably be expected to recur." The commenters claimed that this condition must be considered in setting MACT floors.

While EPA did present a comparison of data from units that had both stack test and hourly CO CEMS data available, commenters stated that the data are not representative. EPA presented only three units which have CEMS data and stack test data, and these units do not have data over a wide load range that could be considered to represent typical operating conditions. Commenters also noted that no CEMS data for liquid units were available. Many commenters suggested that EPA acquire and incorporate more CEMS data when setting the limits to show a more accurate picture of variability. A few commenters also pointed out that CEMS data is needed to characterize intra-unit operating variability due to load changes, because the 99 percent UPL only characterizes inter-unit, steady-state operation. Looking at the CEMS data provided, some commenters used the "start anew" method to calculate a 30-day rolling average, and claimed that the unit would exceed the CO limit for several days, showing that the proposed limits are too low and the CEMS data are not appropriately considered.

Some commenters noted the discrepancy between using stack test data to set the limits, and then having to comply by using CEMS. They suggested that whichever method is used to set the limits, the same method should be used for compliance. Several commenters pointed out that although the vacated Boiler MACT included a requirement for CO CEMS, it did not require CO CEMS data obtained at less than 50 percent of maximum load to be included in the 30-day CO average. Commenters recommended that these data exclusions be incorporated in the compliance provisions of this final rule. In addition, a few commenters cited a ruling by the U.S. Court of Appeals for the D.C. Circuit that "a significant difference between techniques used by the Agency in arriving at standards, and requirements presently prescribed for determining compliance with standards, raises serious questions about the validity of the standard." (*Portland Cement Ass'n* v. *Ruckelshaus*, 486 F.2d 375, 396 (DC Cir. 1973)). These commenters stated that the primary difference between these two methods is that the variability experienced during normal operations will not be captured during the stack test but will become apparent as the facility operates a CEMS over time.

Finally, many commenters stated that the low proposed CO limits will cause additional challenges to boilers that are subject to NO_X limits. These commenters presented graphs and data to demonstrate the inverse relationship between CO and NO_X emissions and noted that changing the boiler operation to reduce CO to such low levels would result in an increase in NO_X emissions. Commenters added that this result would be particularly challenging, and perhaps unproductive for boilers located in ozone non-attainment areas. In addition to increasing NO_X emissions, commenters noted that driving emission levels down to extremely low CO levels would also require boiler operators to increase excess air, thereby reducing the efficiency of the boiler. This operational change would require additional fuel to be combusted, thus increasing emissions of other HAP. These commenters requested that CO limits be balanced with NO_X limits such that boiler efficiency is optimized and State efforts to comply with NAAQS are not hindered. In addition to concerns surrounding competing air quality standards, a few commenters stated that National Fire Protection Act (NFPA) requirements also affect CO emissions at low loads. The NFPA specifies a minimum airflow at which a boiler can operate regardless of load, in order to avoid boiler explosions. At low loads, this NFPA requirement can result in excess air which leads to increased CO emissions. Commenters added that in order to meet the limits as proposed, boilers may have to idle at a higher load, increasing fuel costs and other emissions (NO_X, carbon dioxide (CO_2), and HAP).

Response: In response to the many comments regarding the proposed CO emission limits, EPA performed a re-assessment of the available data. In addition, EPA analyzed additional data that were not used to develop the proposed limits, including data submitted prior to proposal but too late for consideration for purposes of the proposed rule, data submitted during the public comment period, and data submitted after the comment period closed. While many comments were received opposing EPA's proposal to set limits based on stack test data, EPA cannot set limits based on CEMs data because the available CEMS data are insufficient to set emission limits that are reflective of the best performing 12 percent of sources in the various subcategories. First, CEMS data are not available for all of the subcategories. Second, most of the subcategories have only a single CEM data set from one facility. In contrast, a large amount of CO stack test data are available. For these reasons, EPA concluded that it was appropriate to use the stack test data rather than the CEMS data for setting the MACT floors for CO. Industry commenters who recommended that the emission limits be based on CEMS had ample opportunity to conduct CEMS testing (on the units identified as "best performers" based on the 3-run stack tests or on additional units to provide a broader base of data), but very little CEMS data were submitted to EPA after the proposal, and significant data gaps still exist. EPA does agree that, based on the high degree of variability shown by the available data for CO from boilers and process heaters, CEM-based limits could accurately reflect the actual emissions. However, EPA would need sufficient CEMS data to accurately calculate emissions limits, and, therefore, another approach must be used. In this instance, the alternative that EPA selected was to base the limits on 3-run stack test data.

To develop emission limits based on 3-run stack tests, EPA first reviewed the emission test reports for the best performing sources in order to ensure that that data reflected the actual performance of the units during the testing periods. EPA also incorporated data corrections from facilities that submitted test data, and between these two quality assurance measures, EPA has ensured that accurate data were used to establish the emission limits. Second, EPA examined the operating load at which the stack tests were conducted and found that, as pointed out by multiple commenters, the stack test data are representative of conditions at or near full load. Third, EPA determined that the calibration range of the CO analyzer must be considered in determining the minimum value that can be supported technically during a CO stack test. This assessment of calibration range resulted in some low CO levels being adjusted upward, as explained in more detail in the docket memo entitled "Assessment of Minimum Levels of CO that Can Be Established Under Various Analyzer Calibration Ranges." EPA then ranked the data for each subcategory and developed stack test-based emission limits using the 99.9 percent UPL. The 99.9 percent level was selected to provide an additional allowance for variability in the CO emission limits, since the CEM data show that CO levels have a higher degree of variability than other pollutants (for which EPA continues to use the 99 percent UPL). This change from the proposed 99 percent UPL level resulted in about a 10 percent increase in each of the CO emission limits (from the 99 percent UPL using the same data). The CO emission limits in today's rule must be met through the use of a stack test during the initial and annual compliance tests, and parametric monitoring is required to demonstrate continuous compliance. As discussed elsewhere in the preamble, during periods of startup and shutdown, units that would otherwise be subject to a numeric emission limit are instead subject to a work practice standard.

J. Cost Issues

1. Inaccuracy of Basis of Costs

Comment: Numerous commenters disagreed with EPA's cost estimates. Many of them provided specific cost estimates for bringing their facilities into compliance with the proposed regulation to show that the costs were considerably higher than the EPA estimate. The estimations given included vendor data, real project costs, Best Achievable Control Technology and Best Available Retrofit Technology analyses and industrial control cost studies.

Several commenters stated that the Office of Air Quality Planning and Standards (OAQPS) cost manual used to estimate costs was outdated and inaccurate. They noted costs that were missing from the estimates, such as additional man-hours for record-keeping, compliance plan development and implementation, and operating and maintenance expenses. Some costs were said to be underestimated, such as the estimates for catalysts and carbon injection.

Response: The OAQPS cost manual is the accepted basis of cost estimates for EPA regulations. EPA welcomed new information or methods for estimating costs and used the available data to adjust cost estimates where appropriate. EPA did not adjust catalyst costs since this information provided by commenters was based on proprietary cost estimates that could not be scaled to all boiler types. This catalyst also represented a regenerative oxidative catalyst which was a different technology than the CO oxidation catalyst used in initial estimates from EPA at proposal. The main concern about carbon injection costs was that the technology would be needed on far more units than estimated, because the assumption that fabric filters would be adequate to achieve the Hg emission limits was incorrect. EPA has adjusted the emission limits since proposal and notes that none of the units in the MACT floor calculations for solid fuels use activated carbon injection (ACI) control. Of the solid fuel units in the MACT floor calculations that are achieving the floor, only 2 units reported to have fabric filter and ACI installed and 132 units have only a fabric filter installed. The assumption that most units will meet the Hg floor using a fabric filter is reasonable and supported by the data on record. One commenter also questioned the inclusion of a factor for installing ACI equipment to an existing unit, saying that this important factor had been left out of the original calculation. A review of the ACI algorithm confirmed that the factor for installing the unit had been included originally, and no change was necessary.

Comment: One of the most frequently mentioned concerns was the difficulty of retrofitting existing units with add-on control devices, which could lead to the replacement of existing units, at a greater cost that what was estimated in the EPA background documents. Also mentioned were the increased costs associated with non-continental units, for which retrofits could be 1.3 to 2.3 times higher than elsewhere.

Response: EPA does not have enough information to assess the possibility of units being replaced due to difficulty retrofitting existing units. However, regardless of any information on that topic, the emission standards must reflect the floor level of control. Costs and emission impacts estimated for the boiler MACT standard are intended to represent national impacts. Consequently, costs for a specific facility may be lower or higher than what was estimated but on a national basis, we believe that our estimates are reasonable. We would also note that the cost algorithms include a cost factor for retrofitting existing boilers.

Comment: One commenter also expressed concern that process heaters had costs estimated using algorithms based on boiler add-on control costs, giving grossly underestimated process heater control costs.

Response: The algorithms estimate costs based on exhaust gas flow rate volumes and pollutant inlet concentrations and not specific to boiler costs. Some of the algorithms were based on costs from the 2009 HMIWI rulemaking. EPA considers these estimates to be reasonable estimates for both boilers and process heaters and the commenters did not provide an alternative cost estimate specific to process heaters.

Comment: Several commenters stated that the number of affected sources was also underestimated, especially for gas or liquid-fired units, and one requested clarification with regards to the discrepancy between the number of units estimated in the vacated rule and the proposal.

Response: The current inventory gathered for this rulemaking included unit data from industry sources. The public was encouraged to send any updates or changes necessary to correct the source inventory. The current inventory overrides the inventory created previously for the 2004 rulemaking.

2. Unproven Controls

Comment: Many commenters stated that the suggested add-on controls have not been proven capable of simultaneously achieving the low emission limits proposed for the affected units. They expressed dismay at the high cost of adding numerous control devices without any reassurance that the emission limits could be achieved, or that human health would be better protected as a result. Some commenters included quotes from control device vendors stating that they were unable to guarantee the equipment could achieve the removal efficiency necessary to meet the proposed emission limits.

Response: EPA has adjusted emission limits and compliance mechanisms to address these concerns. These adjustments include creation of a consolidated solid fuel subcategory for fuel-based HAP and CO monitoring provisions.

3. Economic Hardship

Comment: Numerous commenters worried that the proposed rule would lead to plant shut-downs, job loss, discouraged use of renewable energy and other negative economic impacts not considered in the rule. The commenters stated that the proposed regulation fails to find balance between job preservation, economic growth and environmental protection and suggested that EPA use their discretionary authority under the CAA to craft a more appropriate rule. A few industry representatives worried that the cumulative impact of multiple EPA regulations was putting U.S. industry at a cost disadvantage compared to international companies, and another asked if costs to comply with other MACT standards were also being taken into account in the RIA. Other commenters stated that the cost of controls necessary for their units to comply with the proposed rule exceeded the cost of the boiler itself, and in many cases exceeded the costs of plant profits in recent years.

Response: EPA appreciates these concerns and, since proposal, has considered opportunities to reduce the costs of compliance with this final rule while continuing to achieve the public health objectives and meet the requirements of the CAA. In a number of cases in this final rule, EPA has adjusted emission limits, compliance mechanisms and subcategories that will make compliance less difficult and costly. In addition, EPA has added a discussion about the interaction of this rule with other rules to section 7.2 of the RIA.

4. Technical Concerns

Comment: In some cases, technical shortcomings of the cost estimates were addressed. For instance, one commenter pointed out that neither chlorine or Hg can be cost effectively removed from liquid fuels down to the proposed emission levels, so the cost of fuels will likely increase as suppliers blend different fuel sources to achieve fuel requirements.

Response: EPA does not have the information necessary to estimate the potential costs that could result from new fuel blends.

Comment: Several commenters had concerns about the use of packed bed scrubbers as a suggested control device. They pointed out that these scrubbers can only be used with relatively small units having an exhaust flow rate no greater than 75,000 standard cubic feet per minute (scfm).

Response: EPA cost estimates took the flow rate capabilities of packed bed scrubbers into account by estimating additional scrubbers for units with flow rates beyond 75,000 scfm.

Comment: Other commenters mentioned that some facilities, most often rural plants in the wood products sector, do not have and cannot obtain a wastewater discharge permit, so they cannot use wet scrubbers and would need to install more costly dry scrubbers to meet the HCl emission limits.

Response: EPA added estimated costs for a Dry Injection/Fabric Filter control alternative for units unable to install wet scrubbers to meet HCl limits.

Comment: Several commenters stated that the proposed CO emission limits would not be achievable at all operating conditions while also meeting NO_X limits, unless controls are added. Several pointed out that tune-ups and combustion modifications such as a linkageless boiler management system (LBMS) and replacement burners would offer inadequate control in most cases.

Response: EPA incorporated additional CO data variability data received during the comment period, adjusted subcategories, and revised compliance mechanisms to address the issues discussed in these comments.

Comment: One commenter pointed out that no documentation was found of a successful LBMS retrofit to existing biomass-to-energy facilities using stoker or fuel cell oven combustion. This commenter cited conversations with several stoker burner manufacturers, and the commenter could find no stoker units that have been retrofitted with an LBMS. They added that manufacturers stated that a successful retrofit to meet the proposed standards was doubtful based on the inherent leakage of air in these types of facilities.

Response: EPA adjusted subcategories and compliance mechanisms and analyzed new CO test data in order to make the CO limits more reasonable. EPA estimates the cost of an LBMS as a placeholder for other combustion improvements that are expected to achieve the CO limits.

Comment: Some wrote to suggest that the number of units requiring activated carbon injection is grossly underestimated, because fabric filters alone would be frequently inadequate to meet the proposed Hg limits. Other commenters suggested that the use of activated carbon would lead to increased fabric filter use and additional costs for disposing of the resulting waste stream.

Response: EPA adjusted Hg emission limits and incorporated a new solid fuel subcategory to address this concern. Further, many of the units in the MACT floor calculations demonstrate that they have achieved the Hg limit without installing activated carbon injection.

Comment: The commenters suggested that far more facilities would need to add fabric filters, rather than the less expensive electrostatic precipitators that had been included in the cost estimates.

Response: EPA is now basing the costs primarily on fabric filter installation, although owners/operators will choose a technology, that can meet the limits, that is best-suited to their process.

Comment: Several times, commenters expressed concern about required add-on controls conflicting with current controls and each other. For instance, one commenter explained small amounts of sulfur trioxide (SO_3) are generated as part of the combustion process for sulfur-containing fuels. The commenter noted that a CO oxidation catalyst or Selective Catalytic Reduction NO_X reduction catalyst, will convert an additional percentage of the $SO_2$to SO_3, which will inhibit Hg removal efficiency of activated carbon injection. SO_3 occupies the active sites on the carbon, taking away those sites from the Hg. Additionally, some of these commenters also pointed out that some of the suggested control combinations have not been used with the affected boilers, so their use is unproven and the retrofit costs unknown.

Response: EPA recognizes the potential interaction of different control devices and has adjusted the subcategories and incorporated additional emission data into the emission limit calculations. The revised limits and subcategories incorporated in this final rule mitigate these concerns. However, specifically addressing the commenters concerns would require an extensive study of emissions and controls, and the time or resources to conduct such a study are not available. EPA used the available data to set standards as required under section 112.

Comment: Some commenters questioned the assumption that facilities will not incur costs to comply with the dioxin/furan standards because they will test for dioxin/furan and be below detection levels. They said this logic does not make sense because EPA has not outlined in the proposed rule any procedures for handling non-detects when performing compliance testing and there are boilers in the EPA emissions database with dioxin/furan emissions that are non-detect but actually measured emissions higher than the proposed limit.

Response: EPA adjusted the dioxin/furan emission limits based on data corrections and corrected procedures for handling non-detect and detection level limited values, making the need for add-on controls to achieve compliance even less likely. For matters of compliance, it should be noted that EPA Method 23 indicates that for compliance demonstrations, a value of zero should be used in place of a value below the detection limit for each non-detect isomer. Adherence to this procedure will ensure that non-detect values do not cause units to violate the emission limits.

Comment: Other commenters disagreed with the EPA assumption that an ESP would be installed to meet the PM emissions limit unless a unit already had a fabric filter installed because sorbent injection will be required to control acid gas, Hg, and dioxin/furan. When sorbent injection is required, the commenters suggested that fabric filters will likely be chosen for units without existing ESPs in order to maximize the performance of the sorbents and minimize the amount of sorbent used.

Response: EPA considers the original approach to be reasonable, and even more realistic, given the adjustments made to the emission limits.

5. Tune-up Costs

Comment: Some commenters questioned the inclusion of a tune-up in the proposed rule and suggested that many sites already perform regular tune-ups. Some commenters also disagreed with annualizing the cost of the tune-up and energy audit over a five year period. The commenters contended that since a tune-up is a service, it must be paid in year 1 to the individual or company performing the work.

Response: EPA agrees that some sites already perform regular tune-ups, which means the requirement will not increase costs for those facilities. EPA considers it appropriate to annualize the cost of a tune-up because the initial tune-up involves more costly steps that make subsequent tune-ups less costly.

6. Testing and Monitoring Costs

Comment: Numerous commenters stated that there will be a significant burden associated with performance testing and that EPA has underestimated these costs. EPA used an estimate of $55,000 plus $6,500 for labor per test, while the commenters provided both estimated and actual testing costs ranging from $60,000 to $90,000. A few commenters also noted when testing for HCl and Hg the testing costs should be doubled, because to meet the 'worst-case' condition stipulation the boilers will have to maximize emissions for two different operating parameters. Additionally, when testing HCl and Hg it is required that units also test for CO, PM, and dioxin/furan which increases costs and complexity of tests. As a result of this paired testing, the number of liquid units estimated to need controls for Hg and HCl and which, therefore, must conduct a performance test is also low. A few commenters contended that if a unit uses CO CEMS a reduction of $3,000 instead of $7,000 from the test estimate is more accurate. These commenters also noted that additional fuel sampling costs for sources firing gas or solids are necessary given the requirements for sources firing more than one type of fuel. Commenters suggested that additional costs for adding ports or scaffolding to stacks; additional space and runs to conduct the sophisticated tests; modifications to the permitting or compliance system; man-hours to enter data into the ERT; increased overtime; lost production, unit downtime, and additional engineering effort to adjust operations; and an increased cost to contract stack testers due to high demand should be factored into the estimated overall testing costs.

Response: EPA's revised cost estimates include two tests for Hg and HCl for each unit in the solid fuel subcategory, in order to account for potential worst case conditions that may be necessary to satisfy this final rule's requirements. In addition, EPA is maintaining the reduced testing option for units that demonstrate emissions a specified percentage below the limits for three years. We have clarified and modified this option to state that performance testing for a given pollutant may be performed every 3 years, instead of annually, if measured emissions during 2 consecutive annual performance tests are less than 75 percent of the applicable emission limit.

Comment: To reduce the testing burden commenters provided input to modify the rule. The proposed rule requires annual stack testing with the opportunity to qualify for testing every 3 years after 3 consecutive successful compliance demonstrations showing emissions, but many commenters suggested that a one-time test or one test every 5 years, coupled with parameter monitoring, is more appropriate

Response: In order to reduce the cost of the testing requirements, EPA adjusted a couple of requirements based on the public comments. First, at proposal, EPA specified that to qualify for testing once every 3 years, sources must meet a level at or below 75 percent of the emission limit for each pollutant for 3 consecutive years. We have modified this option so that performance testing for a given pollutant may be performed every 3 years, instead of annually, if measured emissions during 2 consecutive annual performance tests are less than 75 percent of the applicable emission limit. In addition, for dioxin/furan, we are changing the testing requirement to an initial test demonstrating compliance with the limit and no additional testing, provided that the unit's design is not modified in a manner inconsistent with good combustion practices. In addition, the oxygen level must be maintained at or above 90 percent of the level during the initial compliance test in order to provide an assurance of good combustion. The rationale behind the adjusted dioxin compliance demonstration is that the measured emissions from a limited number of tests indicate that dioxin emissions from boilers and process heaters are very low, and while it is required that sources meet the MACT floor levels, a one-time test and the required parameter monitoring are sufficient to ensure that combustion conditions are maintained and that the dioxin emissions remain low while also minimizing costs.

Comment: Similarly, many commenters contended that costs associated with CO and PM CEMS are underestimated as well. For the installations of CEMS, one commenter provided a cost estimate which was 3 times higher than the EPA estimate, while another said that costs for planning and engineering could be as much as 40 times higher with annual operating costs 3 times higher than EPA estimates. Also, in addition to the capital cost for the instrument itself, expensive certification costs are necessary; one commenter stated that this would be an additional $30,000 to $50,000 for each CEMS. Commenters noted that even for units where CEMS has already been installed, new equipment may be necessary in order to comply with proposed requirements for certifying and calibrating the CEMS. Commenters stated that a data acquisition system would be necessary to manage the data, which can cost more than $10,000. Many commenters also discussed the necessity of adding a stack platform, access, and additional utilities which can exceed $100,000 per stack.

Response: EPA has removed CO CEMS requirements from this final rule. The costs detailed in Appendix J–2 of the memorandum "Methodology for Estimating Control Costs for Industrial, Commercial, Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants—Major Source (2010)" include planning, installations, RATA certifications, performance specifications and QA/QC checks. For PM CEMS, EPA's estimates of installed capital costs include planning, selecting equipment, support facilities, installation, performance specifications tests and QA/QC and is consistent with estimates provided in the 2009 HMIWI rulemaking. EPA does not have information on which facilities would need to install a stack platform or utilities. Given that PM CEMS are required on only the largest units, EPA considers its assumption that most larger facilities have platform and utility access reasonable.

K. Non-hazardous Secondary Materials

Comment: Commenters from several environmental non-governmental organizations were concerned that if EPA moves forward with the proposal to define non-hazardous solid waste to exclude a majority of secondary materials burned for energy recovery, EPA will effectively exempt many boilers from any regulation. These commenters suggested that boilers burning secondary materials are not included in the regulatory definition of solid waste will not be regulated under § 129 because EPA will have labeled the secondary materials burned as a non-waste. Further, they suggested that these non-waste secondary materials are not covered under the boiler rules under § 112. These commenters suggested that while some boilers burning secondary materials will be included in EPA's categories for coal, oil, or biomass fired units, a large group of units will remain unregulated, including units burning only solid secondary materials or only secondary materials and gaseous fuels. One commenter stated that EPA must set section 112 standards for these units to meet its obligations under section 112 and the order in *Sierra Club* v. *EPA,* No 01—1537 (D.D.C.) requiring EPA to "promulgate emission standards assuring that sources accounting for not less than 90 percent of the aggregate emissions of each of the hazardous air pollutants enumerated in Section 112(c)(6) are subject to emission standards under section 112(d)(2) or (d)(4) no later than December 16, 2010." These commenters were concerned that exempting units that burn secondary material from any emission standards will have adverse impacts on the communities that are exposed to the uncontrolled pollutants.

Response: EPA has amended the definitions in this final rule to cover boilers burning non-hazardous secondary materials.

VI. Impacts of This Final Rule

A. What are the air impacts?

Table 2 of this preamble illustrates, for each basic fuel subcategory, the emissions reductions achieved by this final rule (*i.e.,* the difference in emissions between a boiler or process heater controlled to the floor level of control and boilers or process heaters at the current baseline) for new and existing sources. Nationwide emissions of selected HAP (*i.e.,* HCl, HF, Hg, metals, and volative organic compounds) will be reduced by 40,000 tons per year for existing units and 60 tons per year for new units. Emissions of HCl will be reduced by 30,000 tons per year for existing units and 29 tons per year for new units. Emissions of Hg will be reduced by 1.4 tons per year for existing units and 10.8 pounds per year for new units. Emissions of filterable PM will be reduced by 47,400 tons per year for existing units and 85 tons per year for new units. Emissions of non-Hg metals (*i.e.,* antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, Mn, nickel, and selenium) will be reduced by 2,700 tons per year for existing units and will be reduced by 1.5 tons per year for new units. In addition, emissions of SO2 are estimated to be reduced by 442,000 tons per year for existing sources and 400 tons per year for new sources. Emissions of dioxin/furan, will be reduced by 23 grams of TCDD-equivalents per year for existing units and 0.01 gram per year of TCDD-equivalents for new units. A discussion of the methodology used to estimate emissions and emissions reductions is presented in "Revised Methodology for Estimating Cost and Emissions Impacts for Industrial, Commercial, Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants—Major Source (2011)" in the docket.

TABLE 2—SUMMARY OF EMISSIONS REDUCTIONS FOR EXISTING AND NEW SOURCES

(Tons/Yr)

Source	Subcategory	HCl	PM	Non mercury metals [a]	Mercury	VOC
Existing Units	Solid units	27,592	33,299	314	0.6	5,046
	Liquid units	1,936	13,269	2,229	0.7	1,881
	Non-Continental Liquid units.	89	726	115	0.06	0.01
	Gas 1 (NG/RG) units	23	139	0.3	0.009	82
	Gas 1 Metallurgical Furnaces.	0.4	2	0.02	0.001	30
	Gas 2 (other) units	0.4	0.1	0.0009	4.5E–05	111
New Units	Solid units	0	0	0	0	0
	Liquid units	29	85	1.5	0.005	27
	Gas 1 units	0.02	0.1	0.0003	7.9E–06	0.03
	Gas 2 (other) units	0	0	0	0	0

[a] Includes antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, Mn, nickel, and selenium.

B. What are the water and solid waste impacts?

EPA estimated the additional water usage that would result from installing wet scrubbers to meet the emission limits for HCl would be 700 million gallons per year for existing sources and 242,000 gallons per year for new sources. In addition to the increased water usage, an additional 266 million gallons per year of wastewater would be produced for existing sources and 194,000 gallons per year for new sources. The annual costs of treating the additional wastewater are $1.4 million for existing sources and $1,055 for new sources. These costs are accounted for in the control costs estimates.

EPA estimated the additional solid waste that would result from the MACT floor level of control to be 100,450 tons per year for existing sources and 580 tons per year for new sources. Solid waste is generated from flyash and dust captured in PM and Hg controls as well as from spent carbon and spent sorbent that is injected into exhaust streams or used to filter gas streams. The costs of handling the additional solid waste generated are $4.2 million for existing sources and $25,000 for new sources. These costs are also accounted for in the control costs estimates.

A discussion of the methodology used to estimate impacts is presented in "Revised Methodology for Estimating Cost and Emissions Impacts for Industrial, Commercial, Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants—Major Source (2011)".

C. What are the energy impacts?

EPA expects an increase of approximately 1.442 billion kilowatt hours (kWh) in national annual energy usage as a result of this final rule. Of this amount, 1.436 billion kWh would be from existing sources and 6.2 million kWh are estimated from new sources. The increase results from the electricity required to operate control devices, such as wet scrubbers, electrostatic precipitators, and fabric filters which are expected to be installed to meet this final rule. Additionally, EPA expects work practice standards such as boilers tune-ups and combustion controls will improve the efficiency of boilers, resulting in an estimated fuel savings of 53 TBtu each year from existing sources and an additional 11 billion BTU each year from new sources. This fuel savings estimate includes only those fuel savings resulting from gas, liquid, and coal fuels and it is based on the assumption that the work practice standards will achieve 1 percent improvement in efficiency.

D. What are the cost impacts?

To estimate the national cost impacts of this final rule for existing sources, we developed average baseline emission factors for each fuel type/control device combination based on the emission data obtained and contained in the Boiler MACT emission database. If a unit reported emission data, we assigned its unit-specific emission data as its baseline emissions. If a unit did not report emission data but similar units at the facility with the same fuel and combustor design reported data, the average of all similar units at a given facility was assigned as its baseline emissions. If no unit-specific or similar units from the same facility had data available, a baseline average emission factor was assigned to the unit. Units that reported non-detect emission data for a pollutant that did not have a standardized numeric detection limit were assigned to the average of all non-detect emission data for that pollutant. For the remaining units that did not report emission data, we assigned the appropriate emission factors to each existing unit in the inventory database, based on the average emission factors for boilers with similar fuel, design, and control devices. We then compared each unit's baseline emission factors to the final MACT floor emission limit to determine if control devices were needed to meet the emission limits. The control analysis considered fabric filters and activated carbon injection to be the primary control devices for Hg control, ESP for units meeting Hg limits but requiring additional control to meet the PM limits, wet scrubbers, dry injection/fabric filters, or increased caustic rates to meet the HCl limits, depending on whether or not the facility was assumed to have a wastewater discharge permit, tune-ups, replacement burners, and combustion controls for CO and organic HAP control, and carbon injection for dioxin/furan control. We identified where one control device could achieve reductions in multiple pollutants, for example a fabric filter was expected to achieve both PM and Hg control in order to avoid overestimating the costs. We also included costs for testing and monitoring requirements contained in this final rule. The resulting total national cost impact of this final rule is 5.1 billion dollars in capital expenditures and 1.8 billion dollars per year in total annual costs. Considering estimated fuel savings resulting from work practice standards and combustion controls, the total annualized costs are reduced to 1.4 billion dollars. The total capital and annual costs include costs for control devices, work practices, testing and monitoring. Table 3 of this preamble shows the capital and annual cost impacts for each subcategory. Costs include testing and monitoring costs, but not recordkeeping and reporting costs.

TABLE 3—SUMMARY OF CAPITAL AND ANNUAL COSTS FOR NEW AND EXISTING SOURCES

Source	Subcategory	Estimated/projected number of affected units	Capital costs (10^6 $)	Testing and monitoring annualized costs (10^6 $/yr)	Annualized cost (10^6 $/yr) (considering fuel savings)
Existing Units	Solid units	1,014	2,183	108	846
	Liquid units	713	2,656	19.8	828
	Non-Continental Liquid units	27	86	0.7	21
	Gas 1 units	10,797	70	0.3	(325)
	Gas 1 Metallurgical Furnaces	694	4.5	0	(6)
	Gas 2 (other) units	118	79	6.3	37
	Limited Use	477	3.1	0	(25)
Energy Assessment	ALL				27
New Units	Solid units	0	0	0	0
	Liquid units	13	21	0.3	6.1
	Gas (NG/RG) units	34	0.2	0	(0.02)
	Gas (other) units	0	0	0	0

Using Department of Energy projections on fuel expenditures, the number of additional boilers that could be potentially constructed was estimated. The resulting total national cost impact of this final rule in the 3rd year is 21 million dollars in capital expenditures and 6.1 million dollars per year in total annual costs, when considering a 1 percent fuel savings.

Potential control device cost savings and increased recordkeeping and reporting costs associated with the emissions averaging provisions and reduced testing allowance in this final rule are not accounted for in either the capital or annualized cost estimates.

A discussion of the methodology used to estimate cost impacts is presented in "Revised Methodology for Estimating the Control Costs for Industrial, Commercial, and Institutional Boiler and Process Heater NESHAP (2011)" and "Revised Methodology for Estimating Cost and Emission Impacts for Industrial, Commercial, and Industrial Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants—Major Source (2011)" in the Docket.

E. What are the economic impacts?

Under this final rule, EPA's economic model suggests the average national market-level variables (prices, production-levels, consumption, international trade) will not change significantly (*e.g.,* are less than 0.01 percent). EPA performed a screening analysis for impacts on small entities by comparing compliance costs to sales/revenues (*e.g.,* sales and revenue tests). EPA's analysis found the tests were above 3 percent for 8 of the 50 small entities included in the screening analysis.

In addition to estimating this rule's social costs and benefits, EPA has estimated the employment impacts of the final rule. We expect that the rule's direct impact on employment will be small. We have not quantified the rule's indirect or induced impacts. For further explanation and discussion of our analysis, see Chapter 4 of the RIA.

F. What are the benefits of this final rule?

The benefit categories associated with the emission reduction anticipated for this rule can be broadly categorized as those benefits attributable to reduced exposure to hazardous air pollutants (HAPs) and those attributable to exposure to other pollutants. Because we were unable to monetize the benefits associated with reducing HAPs, all monetized benefits reflect improvements in ambient $PM_{2.5}$ and ozone concentrations. This results in an underestimate of the total monetized benefits. We estimated the total monetized benefits of this final regulatory action to be $22 billion to $54 billion (2008$, 3 percent discount rate) in the implementation year (2014). The monetized benefits at a 7 percent discount rate are $20 billion to $49 billion (2008$). Using alternate relationships between fine particulate matter ($PM_{2.5}$) and premature mortality supplied by experts, higher and lower benefits estimates are plausible, but most of the expert-based estimates fall between these two estimates.[8] A summary of the monetized benefits estimates at discount rates of 3 percent and 7 percent is provided in Table 4 of this preamble. A summary of the avoided health incidences is provided in Table 5 of this preamble.

TABLE 4—SUMMARY OF THE MONETIZED BENEFITS ESTIMATES FOR THE FINAL BOILER MACT

[Millions of 2008$] [1]

Pollutant	Emissions reductions (tons)	Total monetized benefits (at 3% discount rate)	Total monetized benefits (at 7% discount rate)
$PM_{2.5}$-related benefits			
Direct $PM_{2.5}$	29,007	$2,100 to $5,100	$1,900 to $4,600.
SO_2	439,901	$20,000 to $49,000	$18,000 to $45,000.
Ozone-related benefits			
VOCs	6,537	$3.6 to $15	$3.6 to $15.

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[8] Roman *et al*, 2008. Expert Judgment Assessment of the Mortality Impact of Changes in Ambient Fine Particulate Matter in the U.S. Environ. Sci. Technol., 42, 7, 2268–2274.

TABLE 4—SUMMARY OF THE MONETIZED BENEFITS ESTIMATES FOR THE FINAL BOILER MACT—Continued

[Millions of 2008$] [1]

Pollutant	Emissions reductions (tons)	Total monetized benefits (at 3% discount rate)	Total monetized benefits (at 7% discount rate)
Total		$22,000 to $54,000	$20,000 to $49,000.

[1] All estimates are for the implementation year (2014), and are rounded to two significant figures so numbers may not sum across rows. All fine particles are assumed to have equivalent health effects. Benefits from reducing hazardous air pollutants (HAP) are not included. These estimates do not include energy disbenefits valued at $22 million. These benefits reflect existing boilers and 47 new boilers anticipated to come online by 2014.

TABLE 5—SUMMARY OF THE AVOIDED HEALTH INCIDENCES FOR THE FINAL BOILER MACT [1]

	Avoided health incidences
Avoided Premature Mortality	2,500 to 6,500.
Avoided Morbidity	
Chronic Bronchitis	1,600.
Acute Myocardial Infarction	4,000.
Hospital Admissions, Respiratory	610.
Hospital Admissions, Cardiovascular	1,300.
Emergency Room Visits, Respiratory	2,400.
Acute Bronchitis	3,700.
Work Loss Days	310,000.
Asthma Exacerbation	41,000.
Minor Restricted Activity Days	1,900,000.
Lower Respiratory Symptoms	44,000.
Upper Respiratory Symptoms	34,000.
School Loss Days	810.

[1] All estimates are for the implementation year (2014), and are rounded to two significant figures. All fine particles are assumed to have equivalent health effects. Benefits from reducing HAP are not included. These benefits reflect existing boilers and 47 new boilers anticipated to come online by 2014.

These quantified benefits estimates represent the human health benefits associated with reducing exposure to $PM_{2.5}$ and ozone. The PM and ozone reductions are the result of emission limits on PM as well as emission limits on other pollutants, including HAP. To estimate the human health benefits, we used the environmental Benefits Mapping and Analysis Program (BenMAP) model to quantify the changes in $PM_{2.5}$- and ozone-related health impacts and monetized benefits based on changes in air quality. This approach is consistent with the recently proposed Transport Rule RIA.[9]

For this final rule, we have expanded and updated the analysis since the proposal in several important ways. Using the Comprehensive Air Quality Model with extensions (CAMx) model, we are able to provide boiler sector-specific air quality impacts attributable to the emission reductions anticipated from this final rule. We believe that this modeling provides estimates that are more appropriate for characterizing the health impacts and monetized benefits from boilers than the generic benefit-per-ton estimates used for the proposal analysis.

To generate the boiler sector-specific benefit-per-ton estimates, we used CAMx to convert emissions of direct $PM_{2.5}$ and $PM_{2.5}$ precursors into changes in ambient $PM_{2.5}$ levels and BenMAP to estimate the changes in human health associated with that change in air quality. Finally, the monetized $PM_{2.5}$ health benefits were divided by the emission reductions to create the boiler sector-specific benefit-per-ton estimates. These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because there is no clear scientific evidence that would support the development of differential effects estimates by particle type. Directly emitted $PM_{2.5}$ and SO_2 are the dominant $PM_{2.5}$ precursors affected by this final rule. Even though we assume that all fine particles have equivalent health effects, the benefit-per-ton estimates vary between precursors because each ton of precursor reduced has a different propensity to form $PM_{2.5}$. For example, SO_2 has a lower benefit-per-ton estimate than direct $PM_{2.5}$ because it does not directly transform into $PM_{2.5}$, and because sulfate particles formed from SO_2 emissions can transport many miles, including over areas with low populations. Direct $PM_{2.5}$ emissions convert directly into ambient $PM_{2.5}$, thus, to the extent that emissions occur in population areas, exposures to direct $PM_{2.5}$ will tend to be higher, and monetized health benefits will be higher than for SO_2 emissions.

In addition, we estimated the ozone benefits for this final rule. Volatile organic compounds (VOC) are the primary ozone precursor affected by this final rule. We used CAMx to convert emissions of VOC into changes in ambient ozone levels and BenMAP to estimate the changes in human health associated with that change in air quality.

Furthermore, CAMx modeling allows us to model the reduced Hg deposition that would occur as a result of the estimated reductions of Hg emissions. Although we are unable to model Hg methylation and human consumption of Hg-contaminated fish, the Hg deposition maps provide an improved qualitative characterization of the Hg benefits associated with this final rulemaking.

For context, it is important to note that the magnitude of the PM benefits is largely driven by the concentration response function for premature mortality. Experts have advised EPA to consider a variety of assumptions, including estimates based on both empirical (epidemiological) studies and

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[9] U.S. Environmental Protection Agency, 2010. RIA for the Proposed Federal Transport Rule. Prepared by Office of Air and Radiation. June. Available on the Internet at *http://www.epa.gov/ttn/ecas/regdata/RIAs/proposaltrria_final.pdf.*

judgments elicited from scientific experts, to characterize the uncertainty in the relationship between $PM_{2.5}$ concentrations and premature mortality. For this final rule, we cite two key empirical studies, one based on the American Cancer Society cohort study[10] and the extended Six Cities cohort study.[11] In the RIA for this final rule, which is available in the docket, we also include benefits estimates derived from expert judgments and other assumptions.

EPA strives to use the best available science to support our benefits analyses. We recognize that interpretation of the science regarding air pollution and health is dynamic and evolving. After reviewing the scientific literature and recent scientific advice, we have determined that the no-threshold model is the most appropriate model for assessing the mortality benefits associated with reducing $PM_{2.5}$ exposure. Consistent with this recent advice, we are replacing the previous threshold sensitivity analysis with a new "lowest measured level (LML)" assessment. While an LML assessment provides some insight into the level of uncertainty in the estimated PM mortality benefits, EPA does not view the LML as a threshold and continues to quantify PM-related mortality impacts using a full range of modeled air quality concentrations.

Most of the estimated PM-related benefits in this final rule would accrue to populations exposed to higher levels of $PM_{2.5}$. Using the Pope, *et al.*, (2002) study, 79 percent of the population is exposed at or above the LML of 7.5 microgram per cubic meter ($\mu g/m^3$). Using the Laden, *et al.*, (2006) study, 34 percent of the population is exposed above the LML of 10 $\mu g/m^3$. It is important to emphasize that we have high confidence in $PM_{2.5}$-related effects down to the lowest LML of the major cohort studies. This fact is important, because as we estimate PM-related mortality among populations exposed to levels of $PM_{2.5}$ that are successively lower, our confidence in the results diminishes. However, our analysis shows that the great majority of the impacts occur at higher exposures.

It should be emphasized that the monetized benefits estimates provided above do not include benefits from several important benefit categories, including reducing other air pollutants, ecosystem effects, and visibility impairment. The benefits from reducing other pollutants have not been monetized in this analysis, including reducing 167,000 tons of CO, 30,000 tons of hydrochloric acid, 820 tons of HF, 23 grams of dioxins/furans, 2,900 pounds of Hg, and 22,700 tons of other metals each year. Specifically, we were unable to estimate the benefits associated with HAPs that would be reduced as a result of this rule due to data, resource, and methodology limitations. Challenges in quantifying the HAP benefits include a lack of exposure-response functions, uncertainties in emissions inventories and background levels, the difficulty of extrapolating risk estimates to low doses, and the challenges of tracking health progress for diseases with long latency periods. Although we do not have sufficient information or modeling available to provide monetized estimates for this rulemaking, we include a qualitative assessment of the health effects of these air pollutants in the RIA for this final rule, which is available in the docket. In addition, we provide maps of reduced mercury deposition anticipated from these rules in the RIA for this final rule.

In addition, the monetized benefits estimates provided in Table 4 do not reflect the disbenefits associated with increased electricity usage from operation of the control devices. We estimate that the increases in emissions of CO_2 would have disbenefits valued at $22 million at a 3 percent discount rate (average). CO_2-related disbenefits were calculated using the social cost of carbon, which is discussed further in the RIA. However, these disbenefits do not change the rounded total monetized benefits. In the RIA, we also provide the monetized CO_2 disbenefits using discount rates of 5 percent (average), 2.5 percent (average), and 3 percent (95th percentile).

This analysis does not include the type of detailed uncertainty assessment found in the 2006 $PM_{2.5}$ NAAQS RIA or 2008 Ozone NAAQS RIA. However, the benefits analyses in these RIA provide an indication of the sensitivity of our results to various assumptions, including the use of alternative concentration-response functions and the fraction of the population exposed to low $PM_{2.5}$ levels.

For more information on the benefits analysis, please refer to the RIA for this final rule that is available in the docket.

G. What are the secondary air impacts?

For units adding controls to meet the proposed emission limits, we anticipate very minor secondary air impacts. The combustion of fuel needed to generate additional electricity would yield slight increases in emissions, including NO_X, CO, PM and SO_2 and an increase in CO_2 emissions. Since NO_X and SO_2 are covered by capped emissions trading programs, and methodological limitations prevent us from quantifying the change in CO and PM, we do not estimate an increase in secondary air impacts for this final rule from additional electricity demand. We do estimate greenhouse gas impacts, which result from increased electricity consumption, to be 954,000 tons per year from existing units and 4,100 tons per year from new units.

VII. Relationship of This Final Action to Section 112(c)(6) of the CAA

Section 112(c)(6) of the CAA requires EPA to identify categories of sources of seven specified pollutants to assure that sources accounting for not less than 90 percent of the aggregate emissions of each such pollutant are subject to standards under CAA Section 112(d)(2) or 112(d)(4). EPA has identified "Industrial Coal Combustion," "Industrial Oil Combustion," "Industrial Wood/Wood Residue Combustion," "Commercial Coal Combustion," "Commercial Oil Combustion," and "Commercial Wood/Wood Residue Combustion" as source categories that emit two of the seven CAA Section 112(c)(6) pollutants: POM and Hg. (The POM emitted is composed of 16 polyaromatic hydrocarbons and extractable organic matter.) In the **Federal Register** notice *Source Category Listing for Section 112(d)(2) Rulemaking Pursuant to Section 112(c)(6) Requirements,* 63 FR 17838, 17849, Table 2 (1998), EPA identified "Industrial Coal Combustion," "Industrial Oil Combustion," "Industrial Wood/Wood Residue Combustion," "Commercial Coal Combustion," "Commercial Oil Combustion," and "Commercial Wood/Wood Residue Combustion" as source categories "subject to regulation" for purposes of CAA Section 112(c)(6) with respect to the CAA Section 112(c)(6) pollutants that these units emit.

Specifically, as byproducts of combustion, the formation of POM is effectively reduced by the combustion and post-combustion practices required to comply with the CAA Section 112 standards. Any POM that do form during combustion are further controlled by the various post-

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[10] Pope *et al*, 2002."Lung Cancer, Cardiopulmonary Mortality, and Long-term Exposure to Fine Particulate Air Pollution." Journal of the American Medical Association 287:1132–1141.

[11] Laden *et al*, 2006. "Reduction in Fine Particulate Air Pollution and Mortality." *American Journal of Respiratory and Critical Care Medicine.* 173: 667–672.

combustion controls. The add-on PM control systems (either fabric filter or wet scrubber) and activated carbon injection in the fabric filter-based systems further reduce emissions of these organic pollutants, and also reduce Hg emissions, as is evidenced by performance data. Specifically, the emission tests obtained at currently operating units show that the proposed MACT regulations will reduce Hg emissions by about 77 percent. It is, therefore, reasonable to conclude that POM emissions will be substantially controlled. Thus, while this final rule does not identify specific numerical emission limits for POM, emissions of POM are, for the reasons noted below, nonetheless "subject to regulation" for purposes of Section 112(c)(6) of the CAA.

In lieu of establishing numerical emissions limits for pollutants such as POM, we regulate surrogate substances. While we have not identified specific numerical limits for POM, CO serves as an effective surrogate for this HAP, because CO, like POM, is formed as a byproduct of combustion, and both would increase with an increase in the level of incomplete combustion.

Consequently, we have concluded that the emissions limits for CO function as a surrogate for control of POM, such that it is not necessary to require numerical emissions limits for POM with respect to boilers and process heaters to satisfy CAA Section 112(c)(6).

To further address POM and Hg emissions, this final rule also includes an energy assessment provision that encourage modifications to the facility to reduce energy demand that lead to these emissions.

VIII. Statutory and Executive Order Reviews

A. Executive Orders 12866 and 13563: Regulatory Planning and Review

Under Executive Orders 12866 (58 FR 51735, October 4, 1993) and 13563 (76 FR 3821, January 21, 2011), this action is an "economically significant regulatory action" because it is likely to 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.

Accordingly, EPA submitted this action to the Office of Management and Budget (OMB) for review under Executive Orders 12866 and 13563 and any changes in response to OMB recommendations have been documented in the docket for this action. For more information on the costs and benefits for this rule see the following table.

SUMMARY OF THE MONETIZED BENEFITS, SOCIAL COSTS, AND NET BENEFITS FOR THE BOILER MACT IN 2014

[Millions of 2008$]

	3% Discount rate	7% Discount rate
	Selected	
Total Monetized Benefits [2]	$22,000 to $54,000	$20,000 to $49,000
Total Social Costs [3]	$1,500	$1,500
Net Benefits	$20,500 to $52,500	$18,500 to $47,500
Non-Monetized Benefits	112,000 tons of CO. 30,000 tons of HCl. 820 tons of HF. 2,800 pounds of Hg. 2,700 tons of other metals. 23 grams of dioxins/furans (TEQ). Health effects from SO_2 exposure. Ecosystem effects. Visibility impairment.	
	Alternative	
Total Monetized Benefits [2]	$18,000 to $43,000	$16,000 to $39,000
Total Social Costs [3]	$1,900	$1,900
Net Benefits	$16,100 to $41,100	$14,100 to $37,100
Non-Monetized Benefits	112,000 tons of CO. 22,000 tons of HCl. 620 tons of HF. 2,400 pounds of Hg. 2,600 tons of other metals. 23 grams of dioxins/furans (TEQ). Health effects from SO_2 exposure. Ecosystem effects. Visibility impairment.	

[1] All estimates are for the implementation year (2014), and are rounded to two significant figures. These results include units anticipated to come online and the lowest cost disposal assumption.

[2] The total monetized benefits reflect the human health benefits associated with reducing exposure to $PM_{2.5}$ through reductions of directly emitted $PM_{2.5}$ and $PM_{2.5}$ precursors such as SO_2, as well as reducing exposure to ozone through reductions of VOCs. It is important to note that the monetized benefits include many but not all health effects associated with $PM_{2.5}$ exposure. Benefits are shown as a range from Pope *et al.* (2002) to Laden *et al.* (2006). These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because there is no clear scientific evidence that would support the development of differential effects estimates by particle type. These estimates include energy disbenefits valued at $23 million for the selected option and $35 million for the alternative option. Ozone benefits are valued at $3.6 to $15 million for both options.

[3] The methodology used to estimate social costs for one year in the multimarket model using surplus changes results in the same social costs for both discount rates.

B. Paperwork Reduction Act

The information collection requirements in this final rule will be submitted for approval to the OMB under the *Paperwork Reduction Act,* 44 U.S.C. 3501 *et seq.* An ICR document has been prepared by EPA (ICR No. 2028.06). 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.

This final rule would require maintenance inspections of the control devices but would not require any notifications or reports beyond those required by the General Provisions aside from the notification of alternative fuel use for those units that are in the Gas 1 subcategory but burn liquid fuels for periodic testing, or during periods of gas curtailment or gas supply emergencies. The recordkeeping requirements require only the specific information needed to determine compliance.

When a malfunction occurs, sources must report them according to the applicable reporting requirements of this Subpart DDDDD. An affirmative defense to civil penalties for exceedances of emission limits that are caused by malfunctions is available to a source if it can demonstrate that certain criteria and requirements are satisfied. The criteria ensure that the affirmative defense is available only where the event that causes an exceedance of the emission limit meets the narrow definition of malfunction in 40 CFR 63.2 (sudden, infrequent, not reasonable preventable and not caused by poor maintenance and or careless operation) and where the source took necessary actions to minimize emissions. In addition, the source must meet certain notification and reporting requirements. For example, the source must prepare a written root cause analysis and submit a written report to the Administrator documenting that it has met the conditions and requirements for assertion of the affirmative defense.

To provide the public with an estimate of the relative magnitude of the burden associated with an assertion of the affirmative defense position adopted by a source, EPA provides an administrative adjustment to this ICR that shows what the notification, recordkeeping and reporting requirements associated with the assertion of the affirmative defense might entail. EPA's estimate for the required notification, reports and records, including the root cause analysis, totals $3,141 and is based on the time and effort required of a source to review relevant data, interview plant employees, and document the events surrounding a malfunction that has caused an exceedance of an emission limit. The estimate also includes time to produce and retain the record and reports for submission to EPA. EPA provides this illustrative estimate of this burden because these costs are only incurred if there has been a violation and a source chooses to take advantage of the affirmative defense.

The annual monitoring, reporting, and recordkeeping burden for this collection (averaged over the first 3 years after the effective date of the standards) is estimated to be $95.9 million. This includes 280,459 labor hours per year at a total labor cost of $26.5 million per year, and total non-labor capital costs of $69.3 million per year. This estimate includes initial and annual performance test, conducting an documenting an energy assessment, conducting fuel specifications for Gas 1 units, repeat testing under worst-case conditions for solid fuel units, conducting and documenting a tune-up, semiannual excess emission reports, maintenance inspections, developing a monitoring plan, notifications, and recordkeeping. Monitoring, testing, tune-up and energy assessment costs and cost were also included in the cost estimates presented in the control costs impacts estimates in section IV.D of this preamble. The total burden for the Federal government (averaged over the first 3 years after the effective date of the standard) is estimated to be 97,563 hours per year at a total labor cost of $5.2 million per year.

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 use 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 in 40 CFR 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.

C. Regulatory Flexibility Act, as Amended by the Small Business Regulatory Enforcement Fairness Act of 1996, 5 U.S.C. 601 et seq.

The RFA generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of today's rule on small entities, small entity is defined as: (1) A small business according to Small Business Administration (SBA) size standards by the North American Industry Classification System category of the owning entity. The range of small business size standards for the 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 which is independently owned and operated and is not dominant in its field.

Pursuant to section 603 of the RFA, EPA prepared an initial regulatory flexibility analysis (IRFA) for the proposed rule and convened a Small Business Advocacy Review Panel to obtain advice and recommendations of representatives of the regulated small entities. A detailed discussion of the Panel's advice and recommendations is found in the final Panel Report (Docket ID No. EPA–HQ–OAR–2002–0058–0797). A summary of the Panel's recommendations is also presented in the preamble to the proposed rule at 75 FR 32044–32045 (June 4, 2010). In the proposed rule, EPA included provisions consistent with four of the Panel's recommendations.

As required by section 604 of the RFA, we also prepared a final regulatory flexibility analysis (FRFA) for today's final rule. The FRFA addresses the issues raised by public comments on the IRFA, which was part of the proposal of this rule. The FRFA, which is included as a section in the RIA, is available for review in the docket and is summarized below.

Section II.A of this preamble describes the reasons that EPA is finalizing this action. The rule is intended to reduce emissions of HAP as required under section 112 of the CAA. Many significant issues were raised during the public comment period, and EPA's responses to those comments are presented in section V of this preamble or in the response to comments document contained in the docket. Significant changes to the rule that resulted from the public comments are described in section IV of this preamble.

The primary comments on the IRFA were provided by SBA, with the remainder of the comments generally supporting SBA's comments. Those comments included the following: EPA should have adopted a health-based compliance alternative (HBCA) which provides alternative emission limits for threshold chemicals; EPA should have adopted additional subcategories, including the following: Subcategories based on fuel type (including coal rank, bagasse, biomass by type, and oil by type), unit design type (*e.g.,* process heater, fluidized bed, stoker, fuel cell, suspension burner), duty cycle, geographic location, boiler size, burner type (with and without low-NO$_X$ burners), and hours of use (limited use); EPA should have minimized facility monitoring and reporting requirements; EPA should not have proposed the energy audit requirement; EPA's proposed emissions standards are too stringent; and, EPA should provide more flexibility for emissions averaging.

In response to the comments on the IRFA and other public comments, EPA made the following changes to the final rule. EPA adopted additional subcategories, including a limited-use subcategory for units that operate less than 10 percent of the operating hours in a year, a non-continental liquid unit subcategory for units with the unique challenges faced by remote island locations, and a combination suspension/grate boiler subcategory. EPA also consolidated the subcategories for units combusting various types of solid fuels, which will simplify compliance and will allow units to combust varying percentages of different solid fuels without triggering subcategory changes. EPA also decreased monitoring and testing costs by eliminating the CO CEMS requirement for units greater than 100 mmBtu/hr and changing the dioxin testing requirement to a one-time test. The final rule also includes work practice standards for additional subcategories, including limited-use units, new small units, and units combusting gaseous fuels that are demonstrated to have similar contaminant levels to natural gas. Finally, EPA is finalizing emission limits that are less stringent than the proposed limits for most of the subcategory/pollutant combinations. The emission limit changes are largely due to the changes in subcategories, data corrections, and incorporation of new data into the floor calculations. Additional details on the changes discussed in this paragraph are included in sections IV and V of this preamble.

While EPA did make significant changes based on public comment, EPA did not finalize a HBCA or HBELs and is maintaining, but clarifying, the energy assessment requirement. The discussion of the HBCA decision is included in section V of this preamble. Some changes to the energy assessment requirement that will reduce costs for small entities include a the following provisions: The energy assessment for facilities with affected boilers and process heaters using less than 0.3 trillion Btu per year heat input will be one day in length maximum. The boiler system and energy use system accounting for at least 50 percent of the energy output will be evaluated to identify energy savings opportunities, within the limit of performing a one-day energy assessment; and the energy assessment for facilities with affected boilers and process heaters using 0.3 to 1.0 trillion Btu per year will be 3 days in length maximum. The boiler system and any energy use system accounting for at least 33 percent of the energy output will be evaluated to identify energy savings opportunities, within the limit of performing a 3-day energy assessment. In addition, energy assessments that have been conducted after January 1, 2008 are considered adequate as long as they meet or are amended to meet the requirements of the energy assessment.

While EPA did not make major adjustments to the emissions averaging provisions, the change to a solid fuel subcategory will enable all solid fuel-fired units at a facility to use the emissions averaging provision for Hg, PM, and HCl.

The rule applies to a many different types of small entities. The table below describes the small entities identified in the Combustion Facility Survey.

CLASSES OF SMALL ENTITIES

NAICS	NAICS description	Total number of facilities	Total number of small entities
111	Crop Production	1	0
113	Forestry and Logging	1	0
115	Support Activities for Agriculture and Forestry	1	0
211	Oil and Gas Extraction	24	3
212	Mining (Except Oil and Gas)	14	1
221	Utilities	183	23
311	Food Manufacturing	110	7
312	Beverage and Tobacco Product Manufacturing	5	0
313	Textile Mills	14	1
314	Textile Product Mills	1	0
316	Leather and Allied Product Manufacturing	3	1
321	Wood Product Manufacturing	183	18
322	Paper Manufacturing	186	14

CLASSES OF SMALL ENTITIES—Continued

NAICS	NAICS description	Total number of facilities	Total number of small entities
323	Printing and Related Support Activities	33	5
324	Petroleum and Coal Products Manufacturing	84	8
325	Chemical Manufacturing	220	17
326	Plastics and Rubber Products Manufacturing	89	11
327	Nonmetallic Mineral Product Manufacturing	41	2
331	Primary Metal Manufacturing	57	6
332	Fabricated Metal Product Manufacturing	46	8
333	Machinery Manufacturing	13	0
334	Computer and Electronic Product Manufacturing	2	0
335	Electrical Equipment, Appliance, and Component Manufacturing	12	0
336	Transportation Equipment Manufacturing	100	7
337	Furniture and Related Product Manufacturing	45	8
339	Miscellaneous Manufacturing	15	1
423	Durable Goods Merchant Wholesalers	1	1
424	Nondurable Goods Merchant Wholesalers	1	0
441	Motor Vehicle and Parts Dealers	1	0
481	Air Transportation	7	0
482	Rail Transportation	1	0
486	Pipeline Transportation	60	0
488	Support Activities for Transportation	3	0
493	Warehousing and Storage	5	1
531	Real Estate	1	0
541	Professional, Scientific, and Technical Services	8	0
561	Administrative and Support Services	1	0
562	Waste Management and Remediation Services	7	2
611	Educational Services	29	2
622	Hospitals	4	0
623	Nursing and Residential Care Facilities	1	0
811	Repair and Maintenance	1	0
921	Executive, Legislative, and Other General Government Support	2	0
928	National Security and International Affairs	23	0

We compared the estimated costs to the sales for these entities. The results are found in the following table.

SALES TESTS USING SMALL COMPANIES IDENTIFIED IN THE COMBUSTION SURVEY

Sample statistic	Proposal	Selected option	Alternative option
Mean	4.9%	4.0%	3.8%
Median	0.4%	0.2%	0.4%
Maximum	72.9%	59.8%	31.4%
Minimum	<0.01%	<0.01%	<0.01%
Ultimate parent company observations	50	50	50
Ultimate parent companies with sale tests exceeding 3%	14	8	13

For more detail please see the RIA.

The information collection activities in this ICR include initial and annual stack tests, fuel analyses, operating parameter monitoring, continuous O2 monitoring for all units greater than 10 mmBtu/hr, continuous emission monitoring for PM at units greater than 250 mmBtu/hr, certified energy audits, annual or biennial tune-ups (depending on the size of the combustion equipment), preparation of a site-specific monitoring plan and a site-specific fuel monitoring plan, one-time and periodic reports, and the maintenance of records. Based on the distribution of major source facilities with affected boilers or process heaters reported in the 2008 survey entitled "Information Collection Effort for Facilities with Combustion Units (ICR No. 2286.01)," there are 1,639 existing facilities with affected boilers or process heaters. Of these, 94 percent are located in the private sector and the remaining 6 percent are located in the public sector. A table included in the FRFA summarizes the types and number of each type of small entities expected to be affected by the major source rule.

The Agency expects that persons with knowledge of .pdf software, spreadsheet and relational database programs will be necessary in order to prepare the report or record. Based on experience with previous emission stack testing, we expect most facilities to contract out preparation of the reports associated with emission stack testing, including creation of the Electronic Reporting Tool submittal which will minimize the need for in depth knowledge of databases or spreadsheet software at the source. We also expect affected sources will need to work with web-based applicability tools and flowcharts to determine the requirements applicable to them, knowledge of the heat input capacity and fuel use of the combustion units at each facility will be necessary in order to develop the reports and determine initial applicability to the rule. Affected facilities will also need skills associated with vendor selection in order to identify service providers that can help them complete their compliance requirements, as necessary.

As required by section 212 of SBREFA, EPA also is preparing a Small Entity Compliance Guide to help small entities comply with this rule. Small entities will be able to obtain a copy of the Small Entity Compliance guide at the following Web site: *http://www.epa.gov/ttn/atw/boiler/boilerpg.html.* The guide should be available by May 20, 2011.

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 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 proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

We have determined that this 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 entitled "Unfunded Mandates Reform Act Analysis for the Proposed Industrial Boilers and Process Heaters NESHAP" under section 202 of the UMRA which is summarized below.

1. Statutory Authority

As discussed in section I of this preamble, the statutory authority for this 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. This NESHAP applies to all ICI 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 this 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.

2. Social Costs and Benefits

The regulatory impact analysis prepared for this final rule, including the Agency's assessment of costs and benefits, is detailed in the "Regulatory Impact Analysis for the Proposed Industrial Boilers and Process Heaters MACT" in the docket. Based on estimated compliance costs associated with this final rule and the predicted change in prices and production in the affected industries, the estimated social costs of this final rule are $1.5 billion (2008 dollars).

It is estimated that 3 years after implementation of this final rule, HAP would be reduced by thousands of tons, including reductions in hydrochloric acid, hydrogen fluoride, metallic HAP including Hg, and several other organic HAP from boilers and process heaters. Studies have determined a relationship between exposure to these HAP and the onset of cancer, however, the Agency is unable to provide a monetized estimate of the HAP benefits at this time. In addition, there are significant reductions in $PM_{2.5}$ and in SO_2 that would occur, including 28 thousand tons of $PM_{2.5}$ and 443 thousand tons of SO_2. These reductions occur within 3 years after the implementation of the proposed regulation and are expected to continue throughout the life of the affected sources. The major health effect associated with reducing $PM_{2.5}$ and $PM_{2.5}$ precursors (such as SO_2) is a reduction in premature mortality. Other health effects associated with $PM_{2.5}$ emission reductions include avoiding cases of chronic bronchitis, heart attacks, 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 $PM_{2.5}$ and SO_2 emissions reductions. For SO_2 and $PM_{2.5}$, 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 visibility effects). Our estimates of the monetized benefits in 2014 associated with the implementation of the proposed alternative is range from $22 billion (2008 dollars) to $54 billion (2008 dollars) when using a 3 percent discount rate (or from $20 billion (2008 dollars) to $49 billion (2008 dollars) when using a 7 percent discount rate). This estimate, at a 3 percent discount rate, is about $20.5 billion (2008 dollars) to $52.5 billion (2008 dollars) higher than the estimated social costs shown earlier in this section. The general approach used to value benefits is discussed in more detail earlier in this preamble. For more detailed information on the benefits estimated for the rulemaking, refer to the RIA in the docket.

3. Future and Disproportionate Costs

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

We do not believe that there will be any disproportionate budgetary effects of this final rule on any particular areas of the country, State or local governments, types of communities (e.g., urban, rural), or particular industry segments. See the results of the "Economic Impact Analysis of the Proposed Industrial Boilers and Process Heaters NESHAP," the results of which are discussed previously in this preamble.

4. Effects on the National Economy

The Unfunded Mandates Act requires that we estimate the effect of this 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 this 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 this 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 a small impact on prices and output, and little impact on communities that may be affected by this 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 small.

5. Consultation With Government Officials

The Unfunded Mandates Act requires that we describe the extent of the Agency'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 proposal. We have consulted with State and local air pollution control officials. We have also held meetings on this final rule with many of the stakeholders from numerous individual companies, institutions, environmental groups, consultants and vendors, labor unions, and other interested parties. We have added materials to the Air Docket to document these meetings.

In addition, we have determined that this final rule contains no regulatory requirements that might significantly or uniquely affect small governments. While some small governments may have some sources affected by this final rule, the impacts are not expected to be significant. Therefore, this final rule is not subject to the requirements of section 203 of the UMRA.

E. Executive Order 13132: Federalism

Executive Order 13132 (64 FR 43255, August 10, 1999), 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" is 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.

This 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. Thus, Executive Order 13132 does not apply to this 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 this proposed rule from State and local officials.

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

Subject to the Executive Order 13175 (65 FR 67249, November 9, 2000) EPA may not issue a regulation that has tribal implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by tribal governments, or EPA consults with tribal officials early in the process of developing the proposed regulation and develops a tribal summary impact statement. Executive Order 13175 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."

EPA has concluded that this action may have tribal implications. However, it will neither impose substantial direct compliance costs on tribal governments, nor preempt Tribal law. This rule would impose requirements on owners and operators of major industrial boilers. We are only aware of a few installations of industrial, commercial, or institutional boilers owned or operated by Indian tribal governments. We conducted outreach to tribal environmental staff on this rule through the Tribal Air Newsletter, discussions at the National Tribal Forum and the monthly conference call with the National Tribal Air Association, we also hosted a webinar on the proposed rule in which tribal environmental staff participated.

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 rule that: (1) Is determined to be "economically significant" as defined under Executive Orders 12866 and 13563, and (2) concerns an environmental health or safety risk that EPA has reason to believe may have a disproportionate effect on children. If the regulatory action meets both criteria, the Agency must evaluate the environmental health or safety effects of this planned rule on children, and explain why this planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by the Agency.

This final rule is not subject to Executive Order 13045 because the Agency does not believe the environmental health risks or safety risks addressed by this action present a disproportionate risk to children. The reason for this determination is that this final rule is based solely on technology performance.

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 proposed rulemaking, and notices of proposed rulemaking: (1)(i) that is a significant regulatory action under Executive Orders 12866, 13563, 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.” This final rule is not a “significant regulatory 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.

We estimate a 0.05 percent price increase for the energy sector and a −0.02 percent percentage change in production. We estimate a 0.09 percent increase in energy imports. For more information on the estimated energy effects, please refer to the economic impact analysis for this final rule. The analysis is available in the public docket.

Therefore, we conclude that this 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 EPA to use voluntary consensus standards in its regulatory 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) that are developed or adopted by voluntary consensus standards bodies. NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

This rulemaking involves technical standards. EPA cites the following standards in the final rule: EPA Methods 1, 2, 2F, 2G, 3A, 3B, 4, 5, 5D, 17, 19, 23, 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 proposed 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 American Society of Mechanical Engineers (ASME) PTC 19–10–1981–Part 10, “Flue and Exhaust Gas Analyses,” is cited in the proposed rule for its manual method for measuring the oxygen, CO_2, and CO 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 Method 3A for identifying CO and oxygen concentrations for this 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 Hg only) for the purpose of this final rule. This standard can be used in the final rule to determine the Hg concentration in stack gases for boilers with rated heat input capacities of greater than 250 MMBtu/hr.

In addition to the voluntary consensus standards EPA used in the proposed rule, the search for emissions measurement procedures identified 15 other voluntary consensus standards. EPA determined that 13 of these 15 standards identified for measuring emissions of the HAP or surrogates subject to emission standards in the proposed rule were impractical alternatives to EPA test methods for the purposes of this final rule. Therefore, EPA does not intend to adopt these standards for this purpose. The reasons for this determination for the 13 methods are discussed below.

The voluntary consensus standard ASTM D3154–00, “Standard Method for Average Velocity in a Duct (Pitot Tube Method),” is impractical as an alternative to EPA Methods 1, 2, 3B, and 4 for the purposes of the proposed rulemaking since the standard appears to lack in quality control and quality assurance requirements. Specifically, ASTM D3154–00 does not include the following: (1) Proof that openings of standard pitot tube have not plugged during the test; (2) if differential pressure gauges other than inclined manometers (*e.g.,* magnehelic gauges) are used, their calibration must be checked after each test series; and (3) the frequency and validity range for calibration of the temperature sensors.

The voluntary consensus standard ASTM D3464–96 (2001), “Standard Test Method Average Velocity in a Duct Using a Thermal Anemometer,” is impractical as an alternative to EPA Method 2 for the purposes of the proposed rule primarily because applicability specifications are not clearly defined, *e.g.,* range of gas composition, temperature limits. Also, the lack of supporting quality assurance data for the calibration procedures and specifications, and certain variability issues that are not adequately addressed by the standard limit EPA’s ability to make a definitive comparison of the method in these areas.

The voluntary consensus standard ISO 10780:1994, “Stationary Source Emissions—Measurement of Velocity and Volume Flowrate of Gas Streams in Ducts,” is impractical as an alternative to EPA Method 2 in the proposed rule. The standard recommends the use of an L-shaped pitot, which historically has not been recommended by EPA. EPA specifies the S-type design which has large openings that are less likely to plug up with dust.

The voluntary consensus standard, CAN/CSA Z223.2–M86 (1999), “Method for the Continuous Measurement of Oxygen, Carbon Dioxide, Carbon Monoxide, Sulphur Dioxide, and Oxides of Nitrogen in Enclosed Combustion Flue Gas Streams,” is unacceptable as a substitute for EPA Method 3A since it does not include quantitative specifications for measurement system performance, most notably the calibration procedures and instrument performance characteristics. The instrument performance characteristics that are provided are nonmandatory and also do not provide the same level of quality assurance as the EPA methods. For example, the zero and span/calibration drift is only checked weekly, whereas the EPA methods require drift checks after each run.

Two very similar voluntary consensus standards, ASTM D5835–95 (2001), “Standard Practice for Sampling Stationary Source Emissions for Automated Determination of Gas Concentration,” and ISO 10396:1993, “Stationary Source Emissions: Sampling for the Automated Determination of Gas Concentrations,” are impractical alternatives to EPA Method 3A for the purposes of this final rule because they lack in detail and quality assurance/quality control requirements. Specifically, these two standards do not include the following: (1) Sensitivity of the method; (2) acceptable levels of analyzer calibration error; (3) acceptable levels of sampling system bias; (4) zero drift and calibration drift limits, time span, and required testing frequency; (5) a method to test the interference response of the analyzer; (6) procedures to determine the minimum sampling time per run and minimum measurement time; and (7) specifications for data recorders, in terms of resolution (all types) and recording intervals (digital and analog recorders, only).

The voluntary consensus standard ISO 12039:2001, "Stationary Source Emissions—Determination of Carbon Monoxide, Carbon Dioxide, and Oxygen—Automated Methods," is not acceptable as an alternative to EPA Method 3A. This ISO standard is similar to EPA Method 3A, but is missing some key features. In terms of sampling, the hardware required by ISO 12039:2001 does not include a 3-way calibration valve assembly or equivalent to block the sample gas flow while calibration gases are introduced. In its calibration procedures, ISO 12039:2001 only specifies a two-point calibration while EPA Method 3A specifies a three-point calibration. Also, ISO 12039:2001 does not specify performance criteria for calibration error, calibration drift, or sampling system bias tests as in the EPA method, although checks of these quality control features are required by the ISO standard.

The voluntary consensus standard ASME PTC–38–80 R85 (1985), "Determination of the Concentration of Particulate Matter in Gas Streams," is not acceptable as an alternative for EPA Method 5 because ASTM PTC–38–80 is not specific about equipment requirements, and instead presents the options available and the pro's and con's of each option. The key specific differences between ASME PTC–38–80 and the EPA methods are that the ASME standard: (1) Allows in-stack filter placement as compared to the out-of-stack filter placement in EPA Methods 5 and 17; (2) allows many different types of nozzles, pitots, and filtering equipment; (3) does not specify a filter weighing protocol or a minimum allowable filter weight fluctuation as in the EPA methods; and (4) allows filter paper to be only 99 percent efficient, as compared to the 99.95 percent efficiency required by the EPA methods.

The voluntary consensus standard ASTM D3685/D3685M–98, "Test Methods for Sampling and Determination of Particulate Matter in Stack Gases," is similar to EPA Methods 5 and 17, but is lacking in the following areas that are needed to produce quality, representative particulate data: (1) Requirement that the filter holder temperature should be between 120° C and 134° C, and not just "above the acid dew-point;" (2) detailed specifications for measuring and monitoring the filter holder temperature during sampling; (3) procedures similar to EPA Methods 1, 2, 3, and 4, that are required by EPA Method 5; (4) technical guidance for performing the Method 5 sampling procedures, *e.g.,* maintaining and monitoring sampling train operating temperatures, specific leak check guidelines and procedures, and use of reagent blanks for determining and subtracting background contamination; and (5) detailed equipment and/or operational requirements, *e.g.,* component exchange leak checks, use of glass cyclones for heavy particulate loading and/or water droplets, operating under a negative stack pressure, exchanging particulate loaded filters, sampling preparation and implementation guidance, sample recovery guidance, data reduction guidance, and particulate sample calculations input.

The voluntary consensus standard ISO 9096:1992, "Determination of Concentration and Mass Flow Rate of Particulate Matter in Gas Carrying Ducts—Manual Gravimetric Method," is not acceptable as an alternative for EPA Method 5. Although sections of ISO 9096 incorporate EPA Methods 1, 2, and 5 to some degree, this ISO standard is not equivalent to EPA Method 5 for collection of particulate matter. The standard ISO 9096 does not provide applicable technical guidance for performing many of the integral procedures specified in Methods 1, 2, and 5. Major performance and operational details are lacking or nonexistent, and detailed quality assurance/quality control guidance for the sampling operations required to produce quality, representative particulate data (*e.g.,* guidance for maintaining and monitoring train operating temperatures, specific leak check guidelines and procedures, and sample preparation and recovery procedures) are not provided by the standard, as in EPA Method 5. Also, details of equipment and/or operational requirements, such as those specified in EPA Method 5, are not included in the ISO standard, *e.g.,* stack gas moisture measurements, data reduction guidance, and particulate sample calculations.

The voluntary consensus standard CAN/CSA Z223.1–M1977, "Method for the Determination of Particulate Mass Flows in Enclosed Gas Streams," is not acceptable as an alternative for EPA Method 5. Detailed technical procedures and quality control measures that are required in EPA Methods 1, 2, 3, and 4 are not included in CAN/CSA Z223.1. Second, CAN/CSA Z223.1 does not include the EPA Method 5 filter weighing requirement to repeat weighing every 6 hours until a constant weight is achieved. Third, EPA Method 5 requires the filter weight to be reported to the nearest 0.1 milligram (mg), while CAN/CSA Z223.1 requires only to the nearest 0.5 mg. Also, CAN/CSA Z223.1 allows the use of a standard pitot for velocity measurement when plugging of the tube opening is not expected to be a problem. Whereas, EPA Method 5 requires an S-shaped pitot.

The voluntary consensus standard EN 1911–1,2,3 (1998), "Stationary Source Emissions-Manual Method of Determination of HCl-Part 1: Sampling of Gases Ratified European Text-Part 2: Gaseous Compounds Absorption Ratified European Text-Part 3: Adsorption Solutions Analysis and Calculation Ratified European Text," is impractical as an alternative to EPA Methods 26 and 26A. Part 3 of this standard cannot be considered equivalent to EPA Method 26 or 26A because the sample absorbing solution (water) would be expected to capture both HCl and chlorine gas, if present, without the ability to distinguish between the two. The EPA Methods 26 and 26A use an acidified absorbing solution to first separate HCl and chlorine gas so that they can be selectively absorbed, analyzed, and reported separately. In addition, in EN 1911 the absorption efficiency for chlorine gas would be expected to vary as the pH of the water changed during sampling.

The voluntary consensus standard EN 13211 (1998), is not acceptable as an alternative to the Hg portion of EPA Method 29 primarily because it is not validated for use with impingers, as in the EPA method, although the method describes procedures for the use of impingers. This European standard is validated for the use of fritted bubblers only and requires the use of a side (split) stream arrangement for isokinetic sampling because of the low sampling rate of the bubblers (up to 3 liters per minute, maximum). Also, only two bubblers (or impingers) are required by EN 13211, whereas EPA Method 29 require the use of six impingers. In addition, EN 13211 does not include many of the quality control procedures of EPA Method 29, especially for the use and calibration of temperature sensors and controllers, sampling train assembly and disassembly, and filter weighing.

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 proposed 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 to subpart DDDDD, 40 CFR part 63, list the EPA testing methods included in the proposed rule. Under § 63.7(f) and § 63.8(f) of subpart A 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. Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629, February 16, 1994) establishes Federal executive policy on environmental justice (EJ). Its main provision directs Federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations, low-income, and Tribal populations in the United States.

This final action establishes national emission standards for new and existing industrial, commercial, institutional boilers and process heaters that combust non-waste materials (*i.e.* natural gas, process gas, fuel oil, biomass, and coal) and that are located at a major source. EPA estimates that there are approximately 13,840 units located at 1,639 facilities covered by this final rule.

This final rule will reduce emissions of all the listed HAP that come from boilers and process heaters. This includes metals (Hg, arsenic, beryllium, cadmium, chromium, lead, Mn, nickel, and selenium), organics (POM, acetaldehyde, acrolein, benzene, dioxin/furan, ethylene dichloride, formaldehyde, and polychlorinated biphenyls), hydrochloric acid, and hydrofluoric acid. Adverse health effects from these pollutants include cancer, irritation of the lungs, skin, and mucus membranes; effects on the central nervous system, damage to the kidneys, and other acute health disorders. This final rule will also result in substantial reductions of criteria pollutants such as CO, NO_X, PM, and SO_2. SO_2 and nitrogen dioxide are precursors for the formation of $PM_{2.5}$ and ozone. Reducing these emissions will reduce ozone and $PM_{2.5}$ formation and associated health effects, such as adult premature mortality, chronic and acute bronchitis, asthma, and other respiratory and cardiovascular diseases. (Please refer to the RIA contained in the docket for this rulemaking.)

Based on the fact that this final rule does not allow emission increases, EPA has determined that this final rule will not have disproportionately high and adverse human health or environmental effects on minority, low-income, or Tribal populations. To address Executive Order 12898, EPA has conducted analyses to determine the aggregate demographic makeup of the communities near affected sources. EPA's demographic analysis of populations within the three-mile radius showed that major source boilers are located in areas where minorities are overrepresented when compared to the national average. For these same areas, there is also an overrepresentation of population below the poverty line as compared to the national average. The results of the demographic analysis are presented in "Review of Environmental Justice Impacts", April 2010, a copy of which is available in the docket. However, to the extent that any minority, low income, or Tribal subpopulation is disproportionately impacted by the current emissions as a result of the proximity of their homes to these sources, that subpopulation also stands to see increased environmental and health benefit from the emissions reductions called for by this rule.

EPA defines "Environmental Justice" to include meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and polices. To promote meaningful involvement, EPA has developed a communication and outreach strategy to ensure that interested communities have access to this final rule and are aware of its content. EPA also ensured that interested communities had an opportunity to comment during the comment period. During the comment period that followed the June 2010 proposal, EPA publicized the rulemaking via EJ newsletters, Tribal newsletters, EJ listservs, and the internet, including the Office of Policy's (OP) Rulemaking Gateway Web site (*http://yosemite.epa.gov/opei/RuleGate.nsf/*). EPA will also provide general rulemaking fact sheets (*e.g.,* why is this important for my community) for EJ community groups and conduct conference calls with interested communities. In addition, State and federal permitting requirements will provide State and local governments and members of affected communities the opportunity to provide comments on the permit conditions associated with permitting the sources affected by this rulemaking.

K. 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. EPA will submit a report containing this final rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the 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. 804(2). This rule will be effective May 20, 2011.

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 21, 2011.

Lisa P. Jackson,

Administrator.

For the reasons stated in the preamble, title 40, chapter I, part 63 of the Code of the 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.*

■ 2. Section 63.14 is amended by:
■ a. Revising paragraphs (b)(27), (b)(35), (b)(39) through (44), (b)(47) through (52), (b)(57), (b)(61), (b)(64), and (i)(1).
■ b. Removing and reserving paragraphs (b)(45), (b)(46), (b)(55), (b)(56), (b)(58) through (60), and (b)(62).
■ c. Adding paragraphs (b)(66) through (68).
■ d. Adding paragraphs (p) and (q).

§ 63.14 Incorporations by reference.

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(b) * * *

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(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, IBR approved for § 63.9307(c)(2).

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(35) ASTM D6784–02 (Reapproved 2008) Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method), approved April 1, 2008, IBR approved for table 1 to subpart DDDDD of this part, table 2 to subpart DDDDD of this part, table 5 to subpart DDDDD of this part, table 12 to subpart DDDDD of this part, and table 4 to subpart JJJJJJ of this part.

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(39) ASTM D388–05 Standard Classification of Coals by Rank, approved September 15, 2005, IBR approved for § 63.7575 and § 63.11237.

(40) ASTM D396–10 Standard Specification for Fuel Oils, approved October 1, 2010, IBR approved for § 63.7575.

(41) ASTM D1835–05 Standard Specification for Liquefied Petroleum (LP) Gases, approved April 1, 2005, IBR approved for § 63.7575 and § 63.11237.

(42) ASTM D2013/D2013M–09 Standard Practice for Preparing Coal Samples for Analysis, approved November 1, 2009, IBR approved for table 6 to subpart DDDDD of this part and table 5 to subpart JJJJJJ of this part.

(43) ASTM D2234/D2234M–10 Standard Practice for Collection of a Gross Sample of Coal, approved January 1, 2010, IBR approved for table 6 to subpart DDDDD of this part and table 5 to subpart JJJJJJ of this part.

(44) ASTM D3173–03 (Reapproved 2008) Standard Test Method for Moisture in the Analysis Sample of Coal and Coke, approved February 1, 2008, IBR approved for table 6 to subpart DDDDD of this part and table 5 to subpart JJJJJJ of this part.

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(47) ASTM D5198–09 Standard Practice for Nitric Acid Digestion of Solid Waste, approved February 1, 2009, IBR approved for table 6 to subpart DDDDD of this part and table 5 to subpart JJJJJJ of this part.

(48) ASTM D5865–10a Standard Test Method for Gross Calorific Value of Coal and Coke, approved May 1, 2010, IBR approved for table 6 to subpart DDDDD of this part and table 5 to subpart JJJJJJ of this part.

(49) ASTM D6323–98 (Reapproved 2003) Standard Guide for Laboratory Subsampling of Media Related to Waste Management Activities, approved August 10, 2003, IBR approved for table 6 to subpart DDDDD of this part and table 5 to subpart JJJJJJ of this part.

(50) ASTM E711–87 (Reapproved 2004) Standard Test Method for Gross Calorific Value of Refuse-Derived Fuel by the Bomb Calorimeter, approved August 28, 1987, IBR approved for table 6 to subpart DDDDD of this part and table 5 to subpart JJJJJJ of this part.

(51) ASTM E776–87 (Reapproved 2009) Standard Test Method for Forms of Chlorine in Refuse-Derived Fuel, approved July 1, 2009, IBR approved for table 6 to subpart DDDDD of this part.

(52) ASTM E871–82 (Reapproved 2006) Standard Test Method for Moisture Analysis of Particulate Wood Fuels, approved November 1, 2006, IBR approved for table 6 to subpart DDDDD of this part and table 5 to subpart JJJJJJ of this part.

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(57) ASTM D6721–01 (Reapproved 2006) Standard Test Method for Determination of Chlorine in Coal by Oxidative Hydrolysis Microcoulometry, approved April 1, 2006, IBR approved for table 6 to subpart DDDDD of this part.

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(61) ASTM D6722–01 (Reapproved 2006) Standard Test Method for Total Mercury in Coal and Coal Combustion Residues by the Direct Combustion Analysis, approved April 1, 2006, IBR approved for table 6 to subpart DDDDD of this part and table 5 to subpart JJJJJJ of this part.

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(64) ASTM D6522–00 (Reapproved 2005), 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, approved October 1, 2005, IBR approved for table 4 to subpart ZZZZ of this part, table 5 to subpart DDDDD of this part, and table 4 to subpart JJJJJJ of this part.

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(66) ASTM D4084–07 Standard Test Method for Analysis of Hydrogen Sulfide in Gaseous Fuels (Lead Acetate Reaction Rate Method), approved June 1, 2007, IBR approved for table 6 to subpart DDDDD of this part.

(67) ASTM D5954–98 (Reapproved 2006), Standard Test Method for Mercury Sampling and Measurement in Natural Gas by Atomic Absorption Spectroscopy, approved December 1, 2006, IBR approved for table 6 to subpart DDDDD of this part.

(68) ASTM D6350–98 (Reapproved 2003) Standard Test Method for Mercury Sampling and Analysis in Natural Gas by Atomic Fluorescence Spectroscopy, approved May 10, 2003, IBR approved for table 6 to subpart DDDDD of this part.

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(i) * * *

(1) ANSI/ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses [Part 10, Instruments and Apparatus],” IBR approved for §§ 63.309(k)(1)(iii), 63.865(b), 63.3166(a)(3), 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), 63.11148(e)(3)(iii), 63.11155(e)(3), 63.11162(f)(3)(iii) and (f)(4), 63.11163(g)(1)(iii) and (g)(2), 63.11410(j)(1)(iii), 63.11551(a)(2)(i)(C), table 5 to subpart DDDDD of this part, table 1 to subpart ZZZZZ of this part, and table 4 to subpart JJJJJJ of this part.

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(p) The following material is available from the U.S. Environmental Protection Agency, 1200 Pennsylvania Avenue, NW., Washington, DC 20460, (202) 272–0167, *http://www.epa.gov.*

(1) National Emission Standards for Hazardous Air Pollutants (NESHAP) for Integrated Iron and Steel Plants—Background Information for Proposed Standards, Final Report, EPA–453/R–01–005, January 2001, IBR approved for § 63.7491(g).

(2) Office Of Air Quality Planning And Standards (OAQPS), Fabric Filter Bag Leak Detection Guidance, EPA–454/R–98–015, September 1997, IBR approved for § 63.7525(j)(2) and § 63.11224(f)(2).

(3) SW–846–3020A, Acid Digestion of Aqueous Samples And Extracts For Total Metals For Analysis By GFAA Spectroscopy, Revision 1, July 1992, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD of this part and table 5 to subpart JJJJJJ of this part.

(4) SW–846–3050B, Acid Digestion of Sediments, Sludges, And Soils, Revision 2, December 1996, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD of this part and table 5 to subpart JJJJJJ of this part.

(5) SW–846–7470A, Mercury In Liquid Waste (Manual Cold-Vapor Technique), Revision 1, September 1994, in EPA Publication No. SW–846,

Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD of this part and table 5 to subpart JJJJJ of this part.

(6) SW–846–7471B, Mercury In Solid Or Semisolid Waste (Manual Cold-Vapor Technique), Revision 2, February 2007, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD of this part and table 5 to subpart JJJJJ of this part.

(7) SW–846–9250, Chloride (Colorimetric, Automated Ferricyanide AAI), Revision 0, September 1986, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD of this part.

(q) The following material is available for purchase from the International Standards Organization (ISO), 1, ch. de la Voie-Creuse, Case postale 56, CH–1211 Geneva 20, Switzerland, +41 22 749 01 11, *http://www.iso.org/iso/home.htm*.

(1) ISO 6978–1:2003(E), Natural Gas—Determination of Mercury—Part 1: Sampling of Mercury by Chemisorption on Iodine, First edition, October 15, 2003, IBR approved for table 6 to subpart DDDDD of this part.

(2) ISO 6978–2:2003(E), Natural gas—Determination of Mercury—Part 2: Sampling of Mercury by Amalgamation on Gold/Platinum Alloy, First edition, October 15, 2003, IBR approved for table 6 to subpart DDDDD of this part.

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

Subpart DDDDD—National Emission Standards for Hazardous Air Pollutants for Major Sources: 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 Limitations and Work Practice Standards

63.7499 What are the subcategories of boilers and process heaters?
63.7500 What emission limitations, work practice standards, and operating limits must I meet?
63.7501 How can I assert an affirmative defense if I exceed an emission limitations during a malfunction?

General Compliance Requirements

63.7505 What are my general requirements for complying with 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?
63.7515 When must I conduct subsequent performance tests, fuel analyses, or tune-ups?
63.7520 What stack tests and procedures must I use?
63.7521 What fuel analyses, fuel specification, and procedures must I use?
63.7522 Can I use emissions 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 limitations, fuel specifications and work practice standards?
63.7533 Can I use emission credits earned from implementation of energy conservation measures to comply with this subpart?

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 limitations, fuel specifications and work practice standards?
63.7541 How do I demonstrate continuous compliance under the emissions averaging provision?

Notification, 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 for New or Reconstructed Boilers and Process Heaters
Table 2 to Subpart DDDDD of Part 63—Emission Limits for Existing Boilers and Process Heaters (Units with heat input capacity of 10 million Btu per hour or greater)
Table 3 to Subpart DDDDD of Part 63—Work Practice Standards
Table 4 to Subpart DDDDD of Part 63—Operating Limits for Boilers and Process Heaters
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
Table 11 to Subpart DDDDD of Part 63—Toxic Equivalency Factors for Dioxins/Furans
Table 12 to Subpart DDDDD of Part 63—Alternative Emission Limits for New or Reconstructed Boilers and Process Heaters That Commenced Construction or Reconstruction After June 4, 2010, and Before May 20, 2011

What This Subpart Covers

§ 63.7480 What is the purpose of this subpart?

This subpart establishes national emission limitations and work practice standards for hazardous air pollutants (HAP) emitted from industrial, commercial, and institutional boilers and process heaters located at major sources of HAP. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations 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, except as specified in § 63.7491. For purposes of this subpart, a major source of HAP is as defined in § 63.2, except that for oil and natural gas production facilities, a major source of HAP is as defined in § 63.761 (subpart HH of this part, National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities).

§ 63.7490 What is the affected source of this subpart?

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

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

(b) A boiler or process heater is new if you commence construction of the boiler or process heater after June 4, 2010, and you meet the applicability criteria at the time you commence construction.

(c) A boiler or process heater is reconstructed if you meet the reconstruction criteria as defined in § 63.2, you commence reconstruction after June 4, 2010, 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 (m) of this section are not subject to this subpart.

(a) An electric utility steam generating unit.

(b) A recovery boiler or furnace covered by subpart MM of this part.

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

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

(e) A refining kettle covered by subpart X of this part.

(f) An ethylene cracking furnace covered by subpart YY of this part.

(g) Blast furnace stoves as described in EPA–453/R–01–005 (incorporated by reference, see § 63.14).

(h) Any boiler or process heater that is part of the affected source subject to another subpart of this part (i.e., another National Emission Standards for Hazardous Air Pollutants in 40 CFR part 63).

(i) Any boiler or process heater that is used as a control device to comply with another subpart of this part, provided that at least 50 percent of the heat input to the boiler is provided by the gas stream that is regulated under another subpart.

(j) Temporary boilers as defined in this subpart.

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

(l) Any boiler specifically listed as an affected source in any standard(s) established under section 129 of the Clean Air Act.

(m) A boiler required to have a permit under section 3005 of the Solid Waste Disposal Act or covered by subpart EEE of this part (e.g., hazardous waste boilers).

§ 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 May 20, 2011 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 March 21, 2014.

(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 source must be in compliance with this subpart upon startup.

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

(e) If you own or operate an industrial, commercial, or institutional boiler or process heater and would be subject to this subpart except for the exemption in § 63.7491(l) for commercial and industrial solid waste incineration units covered by part 60, subpart CCCC or subpart DDDD, and you cease combusting solid waste, you must be in compliance with this subpart on the effective date of the switch from waste to fuel.

Emission Limitations and Work Practice Standards

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

The subcategories of boilers and process heaters, as defined in § 63.7575 are:

(a) Pulverized coal/solid fossil fuel units.

(b) Stokers designed to burn coal/solid fossil fuel.

(c) Fluidized bed units designed to burn coal/solid fossil fuel.

(d) Stokers designed to burn biomass/bio-based solid.

(e) Fluidized bed units designed to burn biomass/bio-based solid.

(f) Suspension burners/Dutch Ovens designed to burn biomass/bio-based solid.

(g) Fuel Cells designed to burn biomass/bio-based solid.

(h) Hybrid suspension/grate burners designed to burn biomass/bio-based solid.

(i) Units designed to burn solid fuel.

(j) Units designed to burn liquid fuel.

(k) Units designed to burn liquid fuel in non-continental States or territories.

(l) Units designed to burn natural gas, refinery gas or other gas 1 fuels.

(m) Units designed to burn gas 2 (other) gases.

(n) Metal process furnaces.

(o) Limited-use boilers and process heaters.

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

(a) You must meet the requirements in paragraphs (a)(1) through (3) of this section, except as provided in paragraphs (b) and (c) of this section. You must meet these requirements at all times.

(1) You must meet each emission limit and work practice standard in Tables 1 through 3, and 12 to this subpart that applies to your boiler or process heater, for each boiler or process heater at your source, except as provided under § 63.7522. If your affected source is a new or reconstructed affected source that commenced construction or reconstruction after June 4, 2010, and before May 20, 2011, you may comply with the emission limits in Table 1 or 12 to this subpart until March 21, 2014. On and after March 21, 2014, you must comply with the emission limits in Table 1 to this subpart.

(2) You must meet each operating limit in Table 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 Table 4 to this subpart, or you wish to establish and monitor an alternative operating limit and alternative monitoring parameters, you must apply to the EPA Administrator for approval of alternative monitoring under § 63.8(f).

(3) At all times, you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

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

(c) Limited-use boilers and process heaters must complete a biennial tune-up as specified in § 63.7540. They are not subject to the emission limits in Tables 1 and 2 to this subpart, the annual tune-up requirement in Table 3 to this subpart, or the operating limits in Table 4 to this subpart. Major sources that have limited-use boilers and process heaters must complete an energy assessment as specified in Table 3 to this subpart if the source has other existing boilers subject to this subpart that are not limited-use boilers.

§ 63.7501 How can I assert an affirmative defense if I exceed an emission limitations during a malfunction?

In response to an action to enforce the emission limitations and operating limits set forth in § 63.7500 you may assert an affirmative defense to a claim for civil penalties for exceeding such standards that are caused by malfunction, as defined at § 63.2. Appropriate penalties may be assessed, however, if you fail to meet your burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

(a) To establish the affirmative defense in any action to enforce such a limit, you must timely meet the notification requirements in paragraph (b) of this section, and must prove by a preponderance of evidence that:

(1) The excess emissions:

(i) Were caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner, and

(ii) Could not have been prevented through careful planning, proper design or better operation and maintenance practices; and

(iii) Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and

(iv) Were not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

(2) Repairs were made as expeditiously as possible when the applicable emission limitations were being exceeded. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and

(3) The frequency, amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions; and

(4) If the excess emissions resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and

(5) All possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment and human health; and

(6) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and

(7) All of the actions in response to the excess emissions were documented by properly signed, contemporaneous operating logs; and

(8) At all times, the facility was operated in a manner consistent with good practices for minimizing emissions; and

(9) A written root cause analysis has been prepared, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the excess emissions resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of excess emissions that were the result of the malfunction.

(b) *Notification.* The owner or operator of the facility experiencing an exceedance of its emission limitat(s) during a malfunction shall notify the Administrator by telephone or facsimile (fax) transmission as soon as possible, but no later than 2 business days after the initial occurrence of the malfunction, if it wishes to avail itself of an affirmative defense to civil penalties for that malfunction. The owner or operator seeking to assert an affirmative defense shall also submit a written report to the Administrator within 45 days of the initial ocurrence of the exceedance of the standard in § 63.7500 to demonstrate, with all necessary supporting documentation, that it has met the requirements set forth in paragraph (a) of this section. The owner or operator may seek an extension of this deadline for up to 30 additional days by submitting a written request to the Administrator before the expiration of the 45 day period. Until a request for an extension has been approved by the Administrator, the owner or operator is subject to the requirement to submit such report within 45 days of the initial occurrence of the exceedance.

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 and operating limits in this subpart. These limits apply to you at all times.

(b) [Reserved]

(c) You must demonstrate compliance with all applicable emission limits using performance testing, fuel analysis, or continuous monitoring systems (CMS), including a continuous emission monitoring system (CEMS) or continuous opacity monitoring system (COMS), where applicable. You may demonstrate compliance with the applicable emission limit for hydrogen chloride or mercury using fuel analysis if the emission rate calculated according to § 63.7530(c) is less than the applicable emission limit. Otherwise, you must demonstrate compliance for hydrogen chloride or mercury using performance testing, if subject to an applicable emission limit listed in Table 1, 2, or 12 to this subpart.

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

(1) For each CMS required in this section (including CEMS, COMS, or continuous parameter monitoring system), you must develop, and submit to the delegated authority for approval upon request, a site-specific monitoring plan that addresses paragraphs (d)(1)(i) through (iii) of this section. You must submit this site-specific monitoring plan, if requested, at least 60 days before your initial performance evaluation of your CMS. This requirement to develop and submit a site specific monitoring plan does not apply to affected sources with existing monitoring plans that apply to CEMS and COMS prepared under appendix B to part 60 of this chapter and that meet the requirements of § 63.7525.

(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)(ii), (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) (as applicable in Table 10 to this subpart), (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.

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 applicable emission limits in Tables 1 or 2 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. For affected sources that burn a single type of fuel, you are exempted from the compliance requirements of 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. For purposes of this subpart, units that use a supplemental fuel only for startup, unit shutdown, and transient flame stability purposes still qualify as affected sources that burn a single type of fuel, and the supplemental fuel is not subject to the fuel analysis requirements under § 63.7521 and Table 6 to this subpart.

(b) For affected sources that elect to demonstrate compliance with the applicable emission limits in Tables 1 or 2 of this subpart for hydrogen chloride or mercury 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) If your boiler or process heater is subject to a carbon monoxide limit, your initial compliance demonstration for carbon monoxide is to conduct a performance test for carbon monoxide according to Table 5 to this subpart. Your initial compliance demonstration for carbon monoxide also includes conducting a performance evaluation of your continuous oxygen monitor according to § 63.7525(a).

(d) If your boiler or process heater subject to a PM limit has a heat input capacity greater than 250 MMBtu per hour and combusts coal, biomass, or residual oil, your initial compliance demonstration for PM is to conduct a performance evaluation of your continuous emission monitoring system for PM according to § 63.7525(b). Boilers and process heaters that use a continuous emission monitoring system for PM are exempt from the performance testing and operating limit requirements specified in paragraph (a) of this section.

(e) For existing affected sources, you must demonstrate initial compliance, as specified in paragraphs (a) through (d) of this section, 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.

(f) If your new or reconstructed affected source commenced construction or reconstruction after June 4, 2010, you must demonstrate initial compliance with the emission limits no later than November 16, 2011 or within 180 days after startup of the source, whichever is later. If you are demonstrating compliance with an emission limit in Table 12 to this subpart that is less stringent than (that is, higher than) the applicable emission limit in Table 1 to this subpart, you must demonstrate compliance with the applicable emission limit in Table 1 no later than September 17, 2014.

(g) For affected sources that ceased burning solid waste consistent with § 63.7495(e) and for which your initial compliance date has passed, you must demonstrate compliance within 60 days of the effective date of the waste-to-fuel switch. If you have not conducted your compliance demonstration for this subpart within the previous 12 months, you must complete all compliance demonstrations for this subpart before you commence or recommence combustion of solid waste.

§ 63.7515 When must I conduct subsequent performance tests, fuel analyses, or tune-ups?

(a) You must conduct all applicable performance tests according to § 63.7520 on an annual basis, except those for dioxin/furan emissions, unless you follow the requirements listed in paragraphs (b) through (e) of this section. Annual performance tests must be completed no more than 13 months after the previous performance test, unless you follow the requirements listed in paragraphs (b) through (e) of this section. Annual performance testing for dioxin/furan emissions is not required after the initial compliance demonstration.

(b) You can conduct performance tests less often for a given pollutant if your performance tests for the pollutant for at least 2 consecutive years show that your emissions are at or below 75 percent of the emission limit, and if there are no changes in the operation of the affected source or air pollution control equipment that could increase emissions. In this case, you 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 37 months after the previous performance test. If you elect to demonstrate compliance using emission averaging under § 63.7522, you must continue to conduct performance tests annually.

(c) If your boiler or process heater continues to meet the emission limit for the pollutant, you may choose to conduct performance tests for the pollutant every third year if your emissions are at or below 75 percent of the emission limit, and if there are no changes in the operation of the affected source or air pollution control equipment that could increase emissions, but each such performance test must be conducted no more than 37 months after the previous performance test. If you elect to demonstrate compliance using emission averaging under § 63.7522, you must continue to conduct performance tests annually. The requirement to test at maximum chloride input level is waived unless the stack test is conducted for HCl. The requirement to test at maximum Hg input level is waived unless the stack test is conducted for Hg.

(d) If a performance test shows emissions exceeded 75 percent of the emission limit for a pollutant, you must conduct annual performance tests for that pollutant until all performance tests over a consecutive 2-year period show compliance.

(e) If you are required to meet an applicable tune-up work practice standard, you must conduct an annual or biennial performance tune-up according to § 63.7540(a)(10) and (a)(11), respectively. Each annual tune-up specified in § 63.7540(a)(10) must be no more than 13 months after the previous tune-up. Each biennial tune-up specified in § 63.7540(a)(11) must be conducted no more than 25 months after the previous tune-up.

(f) If you demonstrate compliance with the mercury or hydrogen chloride based on fuel analysis, you must conduct a monthly fuel analysis according to § 63.7521 for each type of fuel burned that is subject to an emission limit in Table 1, 2, or 12 of this subpart. 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. If 12 consecutive monthly fuel analyses demonstrate compliance, you may request decreased fuel analysis frequency by applying to the EPA Administrator for approval of alternative monitoring under § 63.8(f).

(g) You must report the results of performance tests and the associated initial fuel analyses within 90 days after the completion of the performance tests. This report must 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 must include all applicable information required in § 63.7550.

§ 63.7520 What stack 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 stack test plan according to the requirements in § 63.7(c). You shall conduct all performance tests under such conditions as the Administrator specifies to you based on representative performance of the affected source for the period being tested. Upon request, you shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests.

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

(c) 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 representative operating load conditions while burning the type of fuel or mixture of fuels that has the highest content of chlorine and mercury, and you must demonstrate initial compliance and establish your operating limits based on these performance tests. These requirements could result in the need to conduct more than one performance test. Following each performance test and until the next performance test, you must comply with the operating limit for operating load conditions specified in Table 4 to this subpart.

(d) 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 comply with the minimum applicable sampling times or volumes specified in Tables 1, 2, and 12 to this subpart.

(e) 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 at 40 CFR part 60, appendix A–7 of this chapter to convert the measured particulate matter concentrations, the measured hydrogen chloride 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, fuel specification, and procedures must I use?

(a) For solid, liquid, and gas 2 (other) fuels, you must conduct fuel analyses for chloride and mercury according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable. You are not required to conduct fuel analyses for fuels used for only startup, unit shutdown, and transient flame stability purposes. You are required to conduct fuel analyses only for fuels and units that are subject to emission limits for mercury and hydrogen chloride in Tables 1, 2, or 12 to this subpart. Gaseous and liquid fuels are exempt from requirements in paragraphs (c) and (d) of this section and Table 6 of this subpart.

(b) You must develop and submit a site-specific fuel monitoring 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 conduct an initial compliance demonstration.

(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 from Table 6, with the expected minimum detection levels, to be used for the measurement of 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 you are proposing to use. Methods in Table 6 shall be used until the requested alternative is approved.

(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. You must collect all the material (fines and coarse) in the full cross-section. You must transfer the sample to a clean plastic bag.

(ii) Each composite sample will consist of a minimum of three samples collected at approximately equal 1-hour intervals during the testing period.

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

(i) For each composite sample, you must select a minimum of five sampling locations uniformly spaced over the surface of the pile.

(ii) At each sampling site, you must dig into the pile to a depth of 18 inches. You must 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) You must transfer all samples to a clean plastic bag for further processing.

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

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

(2) You must break sample pieces larger than 3 inches into smaller sizes.

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

(4) You must separate one of the quarter samples as the first subset.

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

(6) You must grind the sample in a mill.

(7) You must 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) You must determine the concentration of pollutants in the fuel (mercury and/or chlorine) 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.

(f) To demonstrate that a gaseous fuel other than natural gas or refinery gas qualifies as an other gas 1 fuel, as defined in § 63.7575, you must conduct a fuel specification analyses for hydrogen sulfide and mercury according to the procedures in paragraphs (g) through (i) of this section and Table 6 to this subpart, as applicable. You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for gaseous fuels other than natural gas or refinery gas that are complying with the limits for units designed to burn gas 2 (other) fuels.

(g) You must develop and submit a site-specific fuel analysis plan for other gas 1 fuels to the EPA Administrator for review and approval according to the following procedures and requirements in paragraphs (g)(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 conduct an initial compliance demonstration.

(2) You must include the information contained in paragraphs (g)(2)(i) through (vi) of this section in your fuel analysis plan.

(i) The identification of all gaseous fuel types other than natural gas or refinery gas 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 specification analysis.

(iii) For each fuel type, a detailed description of the sample location and specific procedures to be used for collecting and preparing the samples if your procedures are different from the sampling methods contained in Table 6. 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. If multiple boilers or process heaters are fueled by a common fuel stream it is permissible to conduct a single gas specification at the common point of gas distribution.

(iv) For each fuel type, the analytical methods from Table 6, with the expected minimum detection levels, to be used for the measurement of hydrogen sulfide and 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 you are proposing to use. Methods in Table 6 shall be used until the requested alternative is approved.

(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.

(h) You must obtain a single fuel sample for each other gas 1 fuel type according to the sampling procedures listed in Table 6 for fuel specification of gaseous fuels.

(i) You must determine the concentration in the fuel of mercury, in units of microgram per cubic meter, and of hydrogen sulfide, in units of parts per million, by volume, dry basis, of each sample for each gas 1 fuel type according to the procedures in Table 6 to this subpart.

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

(a) As an alternative to meeting the requirements of § 63.7500 for particulate matter, hydrogen chloride, or mercury on a boiler or process heater-specific basis, if you have more than one existing boiler or process heater in any subcategory located at your facility, you may demonstrate compliance by emissions averaging, if your averaged emissions are not more than 90 percent of the applicable emission limit, according to the procedures in this section. You may not include new boilers or process heaters in an emissions average.

(b) For a group of two or more existing boilers or process heaters in the same subcategory that each vent to a separate stack, you may average particulate matter, hydrogen chloride, or mercury emissions among existing units to demonstrate compliance with the limits in Table 2 to this subpart if you satisfy the requirements in paragraphs (c), (d), (e), (f), and (g) of this section.

(c) For each existing boiler or process heater in the averaging group, the emission rate achieved during the initial compliance test for the HAP being averaged must not exceed the emission level that was being achieved on May 20, 2011 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 May 20, 2011.

(d) The averaged emissions rate from the existing boilers and process heaters participating in the emissions averaging option must be in compliance with the limits in Table 2 to this subpart at all times following the compliance date specified in § 63.7495.

(e) You must demonstrate initial compliance according to paragraph (e)(1) or (2) of this section using the maximum rated heat input capacity or maximum steam generation capacity of each unit and the results of the initial performance tests or fuel analysis.

(1) You must use Equation 1 of this section to demonstrate that the particulate matter, hydrogen chloride, or mercury emissions from all existing units participating in the emissions averaging option for that pollutant do not exceed the emission limits in Table 2 to this subpart.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} \left(Er \times Hm\right) \div \sum_{i=1}^{n} Hm \qquad \text{(Eq.1)}$$

Where:

AveWeightedEmissions = Average weighted emissions for particulate matter, hydrogen chloride, or mercury, in units of pounds per million Btu of heat input.

Er = Emission rate (as determined during the initial compliance demonstration) of particulate matter, hydrogen chloride, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for particulate matter, hydrogen chloride, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for hydrogen chloride or mercury using the applicable equation in § 63.7530(c).

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

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

1.1 = Required discount factor.

(2) If you are not capable of determining the maximum rated heat input capacity of one or more boilers that generate steam, you may use Equation 2 of this section as an alternative to using Equation 1 of this section to demonstrate that the particulate matter, hydrogen chloride, or mercury emissions from all existing units participating in the emissions averaging option do not exceed the emission limits for that pollutant in Table 2 to this subpart.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n}\left(Er \times Sm \times Cfi\right) \div \sum_{i=1}^{n}\left(Sm \times Cfi\right) \qquad \text{(Eq. 2)}$$

Where:

AveWeightedEmissions = Average weighted emission level for PM, hydrogen chloride, or mercury, in units of pounds per million Btu of heat input.

Er = Emission rate (as determined during the most recent compliance demonstration) of particulate matter, hydrogen chloride, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for particulate matter, hydrogen chloride, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for hydrogen chloride or mercury using the applicable equation in § 63.7530(c).

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

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

1.1 = Required discount factor.

(f) After the initial compliance demonstration described in paragraph (e) of this section, you must demonstrate compliance on a monthly basis determined at the end of every month (12 times per year) according to paragraphs (f)(1) through (3) of this section. The first monthly 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 average weighted emission rate for that month using the actual heat input for each existing unit participating in the emissions averaging option.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n}\left(Er \times Hb\right) \div \sum_{i=1}^{n} Hb \qquad \text{(Eq. 3)}$$

Where:

AveWeightedEmissions = Average weighted emission level for particulate matter, hydrogen chloride, or mercury, in units of pounds per million Btu of heat input, for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration) of particulate matter, hydrogen chloride, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for particulate matter, hydrogen chloride, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for hydrogen chloride or mercury using the applicable equation in § 63.7530(c).

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

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

1.1 = Required discount factor.

(2) If you are not capable of monitoring heat input, you may use Equation 4 of this section as an alternative to using Equation 3 of this section to calculate the average weighted emission rate using the actual steam generation from the boilers participating in the emissions averaging option.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n}\left(Er \times Sa \times Cfi\right) \div \sum_{i=1}^{n}\left(Sa \times Cfi\right) \qquad \text{(Eq. 4)}$$

Where:

AveWeightedEmissions = average weighted emission level for PM, hydrogen chloride, or mercury, in units of pounds per million Btu of heat input for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration of particulate matter, hydrogen chloride, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for particulate matter, hydrogen chloride, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for hydrogen chloride or mercury using the applicable equation in § 63.7530(c).

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

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

1.1 = Required discount factor.

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

$$Eavg = \sum_{i=1}^{n} ERi \div 12 \qquad \text{(Eq. 5)}$$

Where:

Eavg = 12-month rolling average emission rate, (pounds per million Btu heat input)
ERi = Monthly weighted average, for calendar month "i" (pounds per million Btu heat input), as calculated by paragraph (f)(1) or (2) of this section.

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

(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 boilers and process heaters in the averaging group, including for each either the applicable HAP emission level or the control technology installed as of May 20, 2011 and the date on which you are requesting emission averaging to commence;

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

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

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

(v) The operating parameters to be monitored for each control system or device consistent with § 63.7500 and Table 4, 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 delegated 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 load conditions. Following each compliance demonstration and until the next compliance demonstration, you must comply with the operating limit for operating load conditions specified in Table 4 to this subpart.

(3) The delegated 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 delegated 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 unit in the same subcategory.

(h) For a group of two or more existing affected units, each of which vents through a single common stack, you may average particulate matter, hydrogen chloride, or mercury emissions to demonstrate compliance with the limits for that pollutant in Table 2 to this subpart if you satisfy the requirements in paragraph (i) or (j) of this section.

(i) For a group of two or more existing units in the same subcategory, each of which vents through a common emissions control system to a common stack, that does not receive emissions from units in other subcategories or categories, you may treat such averaging group as a single existing unit for purposes of this subpart and comply with the requirements of this subpart as if the group were a single unit.

(j) For all other groups of units subject to the common stack requirements of paragraph (h) of this section, including situations where the exhaust of affected units are each individually controlled and then sent to a common stack, the owner or operator may elect to:

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

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

Where:

En = HAP emission limit, pounds per million British thermal units (lb/MMBtu), parts per million (ppm), or nanograms per dry standard cubic meter (ng/dscm).
ELi = Appropriate emission limit from Table 2 to this subpart for unit i, in units of lb/MMBtu, ppm or ng/dscm.
Hi = Heat input from unit i, MMBtu.

(2) Conduct performance tests according to procedures specified in § 63.7520 in the common stack. If affected units and non-affected units vent to the common stack, the non-affected units must be shut down or vented to a different stack during the performance test unless the facility determines to demonstrate compliance with the non-affected units venting to the stack; and

(3) Meet the applicable operating limit specified in § 63.7540 and Table 8 to this subpart for each emissions control system (except that, if each unit venting to the common stack has an applicable opacity operating limit, then a single continuous opacity monitoring system may be located in the common stack instead of in each duct to the common stack).

(k) The common stack of a group of two or more existing boilers or process heaters in the same subcategory subject to paragraph (h) of this section may be treated as a separate stack for purposes of paragraph (b) of this section and included in an emissions averaging group subject to paragraph (b) of this section.

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

(a) If your boiler or process heater is subject to a carbon monoxide emission limit in Table 1, 2, or 12 to this subpart, you must install, operate, and maintain a continuous oxygen monitor according to the procedures in paragraphs (a)(1) through (6) of this section by the compliance date specified in § 63.7495. The oxygen level shall be monitored at the outlet of the boiler or process heater.

(1) Each CEMS for oxygen (O_2 CEMS) must be installed, operated, and maintained according to the applicable procedures under Performance Specification 3 at 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 O_2 CEMS according

to the requirements in § 63.8(e) and according to Performance Specification 3 at 40 CFR part 60, appendix B.

(3) Each O_2 CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(4) The O_2 CEMS data must be reduced as specified in § 63.8(g)(2).

(5) You must calculate and record 12-hour block average concentrations for each operating day.

(6) For purposes of calculating data averages, you must use all the data collected during all periods in assessing compliance, excluding data collected during periods when the monitoring system malfunctions or is out of control, during associated repairs, and during required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments). Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions. Any period for which the monitoring system malfunctions or is out of control and data are not available for a required calculation constitutes a deviation from the monitoring requirements. Periods when data are unavailable because of required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments) do not constitute monitoring deviations.

(b) If your boiler or process heater has a heat input capacity of greater than 250 MMBtu per hour and combusts coal, biomass, or residual oil, you must install, certify, maintain, and operate a CEMS measuring PM emissions discharged to the atmosphere and record the output of the system as specified in paragraphs (b)(1) through (5) of this section.

(1) Each CEMS shall be installed, certified, operated, and maintained according to the requirements in § 63.7540(a)(9).

(2) For a new unit, the initial performance evaluation shall be completed no later than November 16, 2011 or 180 days after the date of initial startup, whichever is later. For an existing unit, the initial performance evaluation shall be completed no later than September 17, 2014.

(3) Compliance with the applicable emissions limit shall be determined based on the 30-day rolling average of the hourly arithmetic average emissions concentrations using the continuous monitoring system outlet data. The 30-day rolling arithmetic average emission concentration shall be calculated using EPA Reference Method 19 at 40 CFR part 60, appendixA–7.

(4) Collect CEMS hourly averages for all operating hours on a 30-day rolling average basis. Collect at least four CMS data values representing the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CMS calibration, quality assurance, or maintenance activities are being performed.

(5) The 1-hour arithmetic averages required shall be expressed in lb/MMBtu and shall be used to calculate the boiler operating day daily arithmetic average emissions.

(c) If you have an applicable opacity operating limit in this rule, and are not otherwise required to install and operate a PM CEMS or a bag leak detection system, you must install, operate, certify and maintain each COMS according to the procedures in paragraphs (c)(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 Performance Specification 1 at appendix B to part 60 of this chapter.

(2) You must conduct a performance evaluation of each COMS according to the requirements in § 63.8(e) and according to Performance Specification 1 at appendix B to part 60 of this chapter.

(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). You must 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. Any 6-minute period for which the monitoring system is out of control and data are not available for a required calculation constitutes a deviation from the monitoring requirements.

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

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

(1) The continuous parameter monitoring system 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 15-minute period for which the monitoring system is out-of-control and data are not available for a required calculation constitutes a deviation from the monitoring requirements.

(4) You must determine the 4-hour block average of all recorded readings, except as provided in paragraph (d)(3) of this section.

(5) You must record the results of each inspection, calibration, and validation check.

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

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

(2) You must use a flow sensor with a measurement sensitivity of no greater than 2 percent of the expected flow rate.

(3) You must minimize the effects of swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.

(4) You must conduct a flow monitoring system performance evaluation in accordance with your monitoring plan at the time of each performance test but no less frequently than annually. (f) If you have an operating limit that requires the use of a pressure monitoring system, you must meet the requirements in paragraphs (d) and (f)(1) through (6) of this section.

(1) Install the pressure sensor(s) in a position that provides a representative measurement of the pressure (*e.g.*, PM scrubber pressure drop).

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

(3) Use a pressure sensor with a minimum tolerance of 1.27 centimeters of water or a minimum tolerance of 1 percent of the pressure monitoring system operating range, whichever is less.

(4) Perform checks at least once each process operating day to ensure pressure measurements are not obstructed (*e.g.*, check for pressure tap pluggage daily).

(5) Conduct a performance evaluation of the pressure monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(6) If at any time the measured pressure exceeds the manufacturer's specified maximum operating pressure range, conduct a performance evaluation of the pressure monitoring system in accordance with your monitoring plan and confirm that the pressure monitoring system continues to meet the performance requirements in you monitoring plan. Alternatively, install and verify the operation of a new pressure sensor.

(g) If you have an operating limit that requires a pH monitoring system, you must meet the requirements in paragraphs (d) and (g)(1) through (4) of this section.

(1) Install 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) Conduct a performance evaluation of the pH monitoring system in accordance with your monitoring plan at least once each process operating day.

(4) Conduct a performance evaluation (including a two-point calibration with one of the two buffer solutions having a pH within 1 of the pH of the operating limit) of the pH monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than quarterly.

(h) If you have an operating limit that requires a secondary electric power monitoring system for an electrostatic precipitator (ESP) operated with a wet scrubber, you must meet the requirements in paragraphs (h)(1) and (2) of this section.

(1) Install sensors to measure (secondary) voltage and current to the precipitator collection plates.

(2) Conduct a performance evaluation of the electric power monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(i) If you have an operating limit that requires the use of a monitoring system to measure sorbent injection rate (e.g., weigh belt, weigh hopper, or hopper flow measurement device), you must meet the requirements in paragraphs (d) and (i)(1) through (2) of this section.

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

(2) Conduct a performance evaluation of the sorbent injection rate monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(j) If you are not required to use a PM CEMS and 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 the bag leak detection system as specified in paragraphs (j)(1) through (7) of this section.

(1) You must install a bag leak detection sensor(s) in a position(s) that will be representative of the relative or absolute particulate matter loadings for each exhaust stack, roof vent, or compartment (*e.g.,* for a positive pressure fabric filter) of the fabric filter.

(2) Conduct a performance evaluation of the bag leak detection system in accordance with your monitoring plan and consistent with the guidance provided in EPA–454/R–98–015 (incorporated by reference, *see* § 63.14).

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

(4) Use a bag leak detection system equipped with a device to record continuously the output signal from the sensor.

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

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

(k) For each unit that meets the definition of limited-use boiler or process heater, you must monitor and record the operating hours per year for that unit.

§ 63.7530 How do I demonstrate initial compliance with the emission limitations, fuel specifications and work practice standards?

(a) You must demonstrate initial compliance with each emission limit that applies to you by conducting initial performance tests and fuel analyses and establishing operating limits, as applicable, according to § 63.7520, paragraphs (b) and (c) of this section, and Tables 5 and 7 to this subpart. If applicable, you must also install, and operate, maintain all applicable CMS (including CEMS, COMS, and continuous parameter monitoring systems) according to § 63.7525.

(b) If you demonstrate compliance through performance testing, you must establish each site-specific operating limit in Table 4 to this subpart that applies to you according to the requirements in § 63.7520, Table 7 to this subpart, and paragraph (b)(3) 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 (b)(1) and (2) of this section, as applicable. As specified in § 63.7510(a), if your affected source burns a single type of fuel (excluding supplemental fuels used for unit startup, shutdown, or transient flame stabilization), you are not required to perform the initial fuel analysis for each type of fuel burned in your boiler or process heater. However, if you switch fuel(s) and cannot show that the new fuel(s) do (does) not increase the chlorine or mercury input into the unit through the results of fuel analysis, then you must repeat the performance test to demonstrate compliance while burning the new fuel(s).

(1) You must establish the maximum chlorine fuel input (Clinput) during the initial fuel analysis according to the procedures in paragraphs (b)(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 fuel analysis for hydrogen chloride, you must determine the fraction of the total heat input for each fuel type burned (Qi) based on the fuel mixture that has the highest content of chlorine, and the average chlorine concentration of each fuel type burned (Ci).

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

$$Clinput = \sum_{i=1}^{n} \left(Ci \times Qi \right) \quad \text{(Eq. 7)}$$

Where:

Clinput = Maximum amount of chlorine entering the boiler or process heater through fuels burned in units of pounds per million Btu.

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

Qi = 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 Qi.

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

(2) You must establish the maximum mercury fuel input level (Mercuryinput) during the initial fuel analysis using the procedures in paragraphs (b)(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 mercury.

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

(iii) You must establish a maximum mercury input level using Equation 8 of this section.

$$Mercuryinput = \sum_{i=1}^{n} \left(HGi \times Qi \right) \quad \text{(Eq. 8)}$$

Where:

Mercuryinput = Maximum amount of mercury entering the boiler or process heater through fuels burned in units of pounds per million Btu.

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

Qi = 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 Qi.

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

(3) You must establish parameter operating limits according to paragraphs (b)(3)(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, hydrogen chloride, 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 hydrogen chloride 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 operated with a wet scrubber, you must establish the minimum voltage and secondary amperage (or total power input), as defined in § 63.7575, as your operating limits during the three-run performance test. (These operating limits do not apply to electrostatic precipitators that are operated as dry controls without a wet scrubber.)

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

(iv) For activated carbon injection, you must establish the minimum activated carbon injection rate, as defined in § 63.7575, as your operating limit during the three-run performance test.

(v) The operating limit for boilers or process heaters with fabric filters that 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.

(c) 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 (c)(1) through (4) 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 9 of this section.

$$P90 = mean + \left(SD \times t \right) \quad \text{(Eq. 9)}$$

Where:

P90 = 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 hydrogen chloride, the hydrogen chloride emission rate that you calculate for your boiler or process heater using Equation 10 of this section must not exceed the applicable emission limit for hydrogen chloride.

$$HCl = \sum_{i=1}^{n} \left(Ci90 \times Qi \times 1.028 \right) \qquad \text{(Eq. 10)}$$

Where:

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

Ci90 = 90th percentile confidence level concentration of chlorine in fuel type, i, in units of pounds per million Btu as calculated according to Equation 9 of this section.

Qi = 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 Qi.

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 hydrogen chloride to chlorine.

(4) 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 not exceed the applicable emission limit for mercury.

$$Mercury = \sum_{i=1}^{n} \left(Hgi90 \times Qi \right) \qquad \text{(Eq. 11)}$$

Where:

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

Hgi90 = 90th percentile confidence level concentration of mercury in fuel, i, in units of pounds per million Btu as calculated according to Equation 9 of this section.

Qi = 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 Qi.

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

(d) If you own or operate an existing unit with a heat input capacity of less than 10 million Btu per hour, you must submit a signed statement in the Notification of Compliance Status report that indicates that you conducted a tune-up of the unit.

(e) You must include with the Notification of Compliance Status a signed certification that the energy assessment was completed according to Table 3 to this subpart and is an accurate depiction of your facility.

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

(g) If you elect to demonstrate that a gaseous fuel meets the specifications of an other gas 1 fuel as defined in § 63.7575, you must conduct an initial fuel specification analyses according to § 63.7521(f) through (i). If the mercury and hydrogen sulfide constituents in the gaseous fuels will never exceed the specifications included in the definition, you will include a signed certification with the Notification of Compliance Status that the initial fuel specification test meets the gas specifications outlined in the definition of other gas 1 fuels. If your gas constituents could vary above the specifications, you will conduct monthly testing according to the procedures in § 63.7521(f) through (i) and § 63.7540(c) and maintain records of the results of the testing as outlined in § 63.7555(g).

(h) If you own or operate a unit subject emission limits in Tables 1, 2, or 12 of this subpart, you must minimize the unit's startup and shutdown periods following the manufacturer's recommended procedures, if available. If manufacturer's recommended procedures are not available, you must follow recommended procedures for a unit of similar design for which manufacturer's recommended procedures are available. You must submit a signed statement in the Notification of Compliance Status report that indicates that you conducted startups and shutdowns according to the manufacturer's recommended procedures or procedures specified for a unit of similar design if manufacturer's recommended procedures are not available.

§ 63.7533 Can I use emission credits earned from implementation of energy conservation measures to comply with this subpart?

(a) If you elect to comply with the alternative equivalent steam output-based emission limits, instead of the heat input-based limits, listed in Tables 1 and 2 of this subpart and you want to take credit for implementing energy conservation measures identified in an energy assessment, you may demonstrate compliance using emission reduction credits according to the procedures in this section. Owners or operators using this compliance approach must establish an emissions benchmark, calculate and document the emission credits, develop an Implementation Plan, comply with the general reporting requirements, and apply the emission credit according to the procedures in paragraphs (b) through (f) of this section.

(b) For each existing affected boiler for which you intend to apply emissions credits, establish a benchmark from which emission reduction credits may be generated by determining the actual annual fuel heat input to the affected boiler before initiation of an energy conservation activity to reduce energy demand (*i.e.,* fuel usage) according to paragraphs (b)(1) through (4) of this section. The benchmark shall be expressed in trillion Btu per year heat input.

(1) The benchmark from which emission credits may be generated shall be determined by using the most representative, accurate, and reliable process available for the source. The benchmark shall be established for a one-year period before the date that an energy demand reduction occurs, unless it can be demonstrated that a different time period is more representative of historical operations.

(2) Determine the starting point from which to measure progress. Inventory all fuel purchased and generated on-site (off-gases, residues) in physical units (MMBtu, million cubic feet, etc.).

(3) Document all uses of energy from the affected boiler. Use the most recent data available.

(4) Collect non-energy related facility and operational data to normalize, if necessary, the benchmark to current operations, such as building size, operating hours, etc. Use actual, not estimated, use data, if possible and data that are current and timely.

(c) Emissions credits can be generated if the energy conservation measures were implemented after January 14, 2011 and if sufficient information is available to determine the appropriate value of credits.

(1) The following emission points cannot be used to generate emissions averaging credits:

(i) Energy conservation measures implemented on or before January 14, 2011, unless the level of energy demand reduction is increased after January 14, 2011, in which case credit will be allowed only for change in demand reduction achieved after January 14, 2011.

(ii) Emission credits on shut-down boilers. Boilers that are shut down cannot be used to generate credits.

(2) For all points included in calculating emissions credits, the owner or operator shall:

(i) Calculate annual credits for all energy demand points. Use Equation 12 to calculate credits. Energy conservation measures that meet the criteria of paragraph (c)(1) of this section shall not be included, except as specified in paragraph (c)(1)(i) of this section.

(3) Credits are generated by the difference between the benchmark that is established for each affected boiler, and the actual energy demand reductions from energy conservation measures implemented after January 14, 2011. Credits shall be calculated using Equation 12 of this section as follows:

(i) The overall equation for calculating credits is:

$$Credits = \sum_{i=1}^{n} EIS_{iactual} \div EI_{baseline} \qquad \text{(Eq. 12)}$$

Where:

Credits = Energy Input Savings for all energy conservation measures implemented for an affected boiler, million Btu per year.
$EIS_{iactual}$ = Energy Input Savings for each energy conservation measure implemented for an affected boiler, million Btu per year.
$EI_{baseline}$ = Energy Input for the affected boiler, million Btu.
n = Number of energy conservation measures included in the emissions credit for the affected boiler.

(d) The owner or operator shall develop and submit for approval an Implementation Plan containing all of the information required in this paragraph for all boilers to be included in an emissions credit approach. The Implementation Plan shall identify all existing affected boilers to be included in applying the emissions credits. The Implementation Plan shall include a description of the energy conservation measures implemented and the energy savings generated from each measure and an explanation of the criteria used for determining that savings. You must submit the implementation plan for emission credits to the applicable delegated authority for review and approval no later than 180 days before the date on which the facility intends to demonstrate compliance using the emission credit approach.

(e) The emissions rate from each existing boiler participating in the emissions credit option must be in compliance with the limits in Table 2 to this subpart at all times following the compliance date specified in § 63.7495.

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

(1) You must use Equation 13 of this section to demonstrate that the emissions from the affected boiler participating in the emissions credit compliance approach do not exceed the emission limits in Table 2 to this subpart.

$$E_{adj} = E_m \times (1 - EC) \qquad \text{(Eq. 13)}$$

Where:

E_{adj} = Emission level adjusted applying the emission credits earned, lb per million Btu steam output for the affected boiler.
E_m = Emissions measured during the performance test, lb per million Btu steam output for the affected boiler.
EC = Emission credits from equation 12 for the affected boiler.

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) You must operate the monitoring system and collect data at all required intervals at all times that the affected source is operating, except for periods of monitoring system malfunctions or out of control periods (*see* § 63.8(c)(7) of this part), and required monitoring system quality assurance or control activities, including, as applicable, calibration checks and required zero and span adjustments. A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. You are required to effect monitoring system repairs in response to monitoring system malfunctions or out-of-control periods and to return the monitoring system to operation as expeditiously as practicable.

(c) You may not use data recorded during monitoring system malfunctions or out-of-control periods, repairs associated with monitoring system malfunctions or out-of-control periods, or required monitoring system quality assurance or control activities in data averages and calculations used to report emissions 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.

(d) Except for periods of monitoring system malfunctions or out-of-control periods, repairs associated with monitoring system malfunctions or out-of-control periods, and required monitoring system quality assurance or quality control activities including, as applicable, calibration checks and required zero and span adjustments, failure to collect required data is a deviation of the monitoring requirements.

§ 63.7540 How do I demonstrate continuous compliance with the emission limitations, fuel specifications and work practice standards?

(a) You must demonstrate continuous compliance with each emission limit, operating limit, and work practice standard in Tables 1 through 3 to this subpart that applies to you according to the methods specified in Table 8 to this subpart and paragraphs (a)(1) through (11) of this section.

(1) Following the date on which the initial compliance demonstration is completed or is required to be completed under §§ 63.7 and 63.7510, whichever date comes first, operation above the established maximum or below the established minimum operating limits shall constitute a deviation of established operating limits listed in Table 4 of this subpart except during performance tests conducted to determine compliance with the emission limits or to establish new operating limits. Operating limits must

be confirmed or reestablished during performance tests.

(2) As specified in § 63.7550(c), 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 hydrogen chloride and mercury than the applicable emission limit for each pollutant (if you demonstrate compliance through fuel analysis), or result in lower fuel input of chlorine and mercury than the maximum values calculated during the last performance test (if you demonstrate compliance through performance testing).

(3) If you demonstrate compliance with an applicable hydrogen chloride emission limit through fuel analysis and you plan to burn a new type of fuel, you must recalculate the hydrogen chloride 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 hydrogen chloride emission rate from your boiler or process heater under these new conditions using Equation 10 of § 63.7530. The recalculated hydrogen chloride emission rate must be less than the applicable emission limit.

(4) If you demonstrate compliance with an applicable hydrogen chloride 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 chlorine input using Equation 7 of § 63.7530. If the results of recalculating the maximum chlorine input using Equation 7 of § 63.7530 are greater 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 hydrogen chloride 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(b).

(5) 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)(5)(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.

(6) 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 8 of § 63.7530. If the results of recalculating the maximum mercury input using Equation 8 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(b).

(7) 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 as soon as practical, 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.

(8) [Reserved].

(9) The owner or operator of an affected source using a CEMS measuring PM emissions to meet requirements of this subpart shall install, certify, operate, and maintain the PM CEMS as specified in paragraphs (a)(9)(i) through (a)(9)(iv) of this section.

(i) The owner or operator shall conduct a performance evaluation of the PM CEMS according to the applicable requirements of § 60.13, and Performance Specification 11 at 40 CFR part 60, appendix B of this chapter.

(ii) During each PM correlation testing run of the CEMS required by Performance Specification 11 at 40 CFR part 60, appendix B of this chapter, PM and oxygen (or carbon dioxide) data shall be collected concurrently (or within a 30-to 60-minute period) by both the CEMS and conducting performance tests using Method 5 or 5B at 40 CFR part 60, appendix A–3 or Method 17 at 40 CFR part 60, appendix A–6 of this chapter.

(iii) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 2 at 40 CFR part 60, appendix F of this chapter. Relative Response Audits must be performed annually and Response Correlation Audits must be performed every 3 years.

(iv) After December 31, 2011, within 60 days after the date of completing each CEMS relative accuracy test audit or performance test conducted to demonstrate compliance with this subpart, you must submit the relative accuracy test audit data and performance test data to EPA by successfully submitting the data electronically into EPA's Central Data Exchange by using the Electronic Reporting Tool (see *http://www.epa.gov/ttn/chief/ert/ert tool.html/*).

(10) If your boiler or process heater is in either the natural gas, refinery gas, other gas 1, or Metal Process Furnace subcategories and has a heat input capacity of 10 million Btu per hour or greater, you must conduct a tune-up of the boiler or process heater annually to demonstrate continuous compliance as specified in paragraphs (a)(10)(i) through (a)(10)(vi) of this section. This requirement does not apply to limited-use boilers and process heaters, as defined in § 63.7575.

(i) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (you may delay the burner inspection until the next scheduled unit shutdown, but you must inspect each burner at least once every 36 months);

(ii) Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available;

(iii) Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly;

(iv) Optimize total emissions of carbon monoxide. This optimization should be consistent with the manufacturer's specifications, if available;

(v) Measure the concentrations in the effluent stream of carbon monoxide in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made); and

(vi) Maintain on-site and submit, if requested by the Administrator, an annual report containing the information in paragraphs (a)(10)(vi)(A) through (C) of this section,

(A) The concentrations of carbon monoxide in the effluent stream in parts per million by volume, and oxygen in volume percent, measured before and after the adjustments of the boiler;

(B) A description of any corrective actions taken as a part of the combustion adjustment; and

(C) The type and amount of fuel used over the 12 months prior to the annual adjustment, but only if the unit was physically and legally capable of using more than one type of fuel during that period. Units sharing a fuel meter may estimate the fuel use by each unit.

(11) If your boiler or process heater has a heat input capacity of less than 10 million Btu per hour, or meets the definition of limited-use boiler or process heater in § 63.7575, you must conduct a biennial tune-up of the boiler or process heater as specified in paragraphs (a)(10)(i) through (a)(10)(vi) of this section to demonstrate continuous compliance.

(12) If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within one week of startup.

(b) You must report each instance in which you did not meet each emission limit and operating limit in Tables 1 through 4 to this subpart that apply to you. These instances are deviations from the emission limits in this subpart. These deviations must be reported according to the requirements in § 63.7550.

(c) If you elected to demonstrate that the unit meets the specifications for hydrogen sulfide and mercury for the other gas 1 subcategory and you cannot submit a signed certification under § 63.7545(g) because the constituents could exceed the specifications, you must conduct monthly fuel specification testing of the gaseous fuels, according to the procedures in § 63.7521(f) through (i).

§ 63.7541 How do I demonstrate continuous compliance under the emissions 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 (5) of this section.

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

(2) You must maintain the applicable opacity limit according to paragraphs (a)(2)(i) and (ii) of this section.

(i) For each existing unit participating in the emissions averaging option that is equipped with a dry control system and not vented to a common stack, maintain opacity at or below the applicable limit.

(ii) For each group of units participating in the emissions averaging option where each unit in the group is equipped with a dry control system and vented to a common stack that does not receive emissions from non-affected units, maintain opacity at or below the applicable limit at the common stack.

(3) For each existing unit 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.

(4) For each existing unit 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.

(5) For each existing unit participating in the emissions averaging option venting to a common stack configuration containing affected units from other subcategories, maintain the appropriate operating limit for each unit as specified in Table 4 to this subpart that applies.

(b) Any instance where the owner or operator fails to comply with the continuous monitoring requirements in paragraphs (a)(1) through (5) of this section is a deviation.

Notification, Reports, and Records

§ 63.7545 What notifications must I submit and when?

(a) You must submit to the delegated authority 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 May 20, 2011, you must submit an Initial Notification not later than 120 days after May 20, 2011.

(c) As specified in § 63.9(b)(4) and (b)(5), if you startup your new or reconstructed affected source on or after May 20, 2011, 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 60 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 the initial compliance demonstration for each affected source, 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 all performance test and/or other initial compliance demonstrations for the affected source according to § 63.10(d)(2). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (8), as applicable.

(1) A description of the affected unit(s) including identification of which subcategory the unit is in, the design heat input capacity of the unit, a description of the add-on controls used on the unit, description of the fuel(s) burned, including whether the fuel(s) were determined by you or EPA through a petition process to be a non-waste under § 241.3, whether the fuel(s) were processed from discarded non-hazardous secondary materials within the meaning of § 241.3, and justification for the selection of fuel(s) burned during the compliance demonstration.

(2) Summary of the results of all performance tests and fuel analyses, and calculations conducted to demonstrate initial compliance including all established operating limits.

(3) A summary of the maximum carbon monoxide emission levels recorded during the performance test to show that you have met any applicable emission standard in Table 1, 2, or 12 to this subpart.

(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 and identification of whether you plan to demonstrate compliance by using emission credits through energy conservation:

(i) If you plan to demonstrate compliance by emission averaging, report the emission level that was being achieved or the control technology employed on May 20, 2011.

(6) A signed certification that you have met all applicable emission limits and work practice standards.

(7) If you had a deviation from any emission limit, work practice standard, or operating limit, 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.

(8) In addition to the information required in § 63.9(h)(2), your notification of compliance status must include the following certification(s) of compliance, as applicable, and signed by a responsible official:

(i) "This facility complies with the requirements in § 63.7540(a)(10) to conduct an annual or biennial tune-up, as applicable, of each unit."

(ii) "This facility has had an energy assessment performed according to § 63.7530(e)."

(iii) Except for units that qualify for a statutory exemption as provided in section 129(g)(1) of the Clean Air Act, include the following: "No secondary materials that are solid waste were combusted in any affected unit."

(f) If you operate a unit designed to burn natural gas, refinery gas, or other gas 1 fuels that is subject to this subpart, and you intend to use a fuel other than natural gas, refinery gas, or other gas 1 fuel to fire the affected unit during a period of natural gas curtailment or supply interruption, as defined in § 63.7575, you must submit a notification of alternative fuel use within 48 hours of the declaration of each period of natural gas curtailment or supply interruption, as defined in § 63.7575. The notification must include the information specified in paragraphs (f)(1) through (5) of 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.

(g) If you intend to commence or recommence combustion of solid waste, you must provide 30 days prior notice of the date upon which you will commence or recommence combustion of solid waste. The notification must identify:

(1) The name of the owner or operator of the affected source, the location of the source, the boiler(s) or process heater(s) that will commence burning solid waste, and the date of the notice.

(2) The currently applicable subcategory under this subpart.

(3) The date on which you became subject to the currently applicable emission limits.

(4) The date upon which you will commence combusting solid waste.

(h) If you intend to switch fuels, and this fuel switch may result in the applicability of a different subcategory, you must provide 30 days prior notice of the date upon which you will switch fuels. The notification must identify:

(1) The name of the owner or operator of the affected source, the location of the source, the boiler(s) that will switch fuels, and the date of the notice.

(2) The currently applicable subcategory under this subpart.

(3) The date on which you became subject to the currently applicable standards.

(4) The date upon which you will commence the fuel switch.

§ 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. For units that are subject only to a requirement to conduct an annual or biennial tune-up according to § 63.7540(a)(10) or (a)(11), respectively, and not subject to emission limits or operating limits, you may submit only an annual or biennial compliance report, as applicable, as specified in paragraphs (b)(1) through (5) of this section, instead of a semi-annual compliance report.

(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 (or 1 or 2 year, as applicable, if submitting an annual or biennial compliance report) 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. The first annual or biennial compliance report must be postmarked no later than January 31.

(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. Annual and biennial compliance reports must cover the applicable one or two year periods from January 1 to 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. Annual and biennial compliance reports must be postmarked no later than January 31.

(5) For each affected source that is subject to permitting regulations pursuant to part 70 or part 71 of this chapter, and if the delegated authority has established dates for submitting semiannual reports pursuant to § 70.6(a)(3)(iii)(A) or § 71.6(a)(3)(iii)(A), you may submit the first and subsequent compliance reports according to the dates the delegated 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 (13) 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 (or annual or biennial) reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by EPA or your basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure.

(5) A summary of the results of the annual performance tests for affected sources subject to an emission limit, a summary of any fuel analyses associated with performance tests, and documentation of any operating limits that were reestablished during this test, if applicable. If you are conducting performance tests once every 3 years consistent with § 63.7515(b) or (c), the date of the last 2 performance tests, a comparison of the emission level you achieved in the last 2 performance tests to the 75 percent emission limit threshold required in § 63.7515(b) or (c), and a statement as to whether there have been any operational changes since the last performance test that could increase emissions.

(6) A signed statement indicating that you burned no new types of fuel in an affected source subject to an emission limit. Or, if you did burn a new type of fuel and are subject to a hydrogen chloride emission limit, 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 hydrogen chloride emission rate using Equation 10 of § 63.7530 that demonstrates that your source is still meeting the emission limit for hydrogen chloride emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel and are subject to a mercury emission limit, you must submit the calculation of mercury input, using Equation 8 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 in an affected source subject to an emission limit and you cannot demonstrate compliance with the maximum chlorine input operating limit using Equation 7 of § 63.7530 or the maximum mercury input operating limit using Equation 8 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) A summary of any monthly fuel analyses conducted to demonstrate compliance according to §§ 63.7521 and 63.7530 for affected sources subject to emission limits, and any fuel specification analyses conducted according to § 63.7521(f) and § 63.7530(g).

(9) If there are no deviations from any emission limits or operating limits in this subpart that apply to you, a statement that there were no deviations from the emission limits or operating limits during the reporting period.

(10) If there were no deviations from the monitoring requirements including no periods during which the CMSs, including CEMS, COMS, and continuous parameter monitoring systems, were out of control as specified in § 63.8(c)(7), a statement that there were no deviations and no periods during which the CMS were out of control during the reporting period.

(11) If a malfunction occurred during the reporting period, the report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by you during a malfunction of a boiler, process heater, or associated air pollution control device or CMS to minimize emissions in accordance with § 63.7500(a)(3), including actions taken to correct the malfunction.

(12) Include the date of the most recent tune-up for each unit subject to only the requirement to conduct an annual or biennial tune-up according to § 63.7540(a)(10) or (a)(11), respectively. Include the date of the most recent burner inspection if it was not done annually or biennially and was delayed until the next scheduled unit shutdown.

(13) If you plan to demonstrate compliance by emission averaging, certify the emission level achieved or the control technology employed is no less stringent that the level or control technology contained in the notification of compliance status in § 63.7545(e)(5)(i).

(d) For each deviation from an emission limit or operating limit in this subpart that occurs at an affected source where you are not using a CMS to comply with that emission limit or operating limit, the compliance report must additionally contain the information required in paragraphs (d)(1) through (4) of this section.

(1) The total operating time of each affected source during the reporting period.

(2) A description of the deviation and which emission limit or operating limit 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 limits.

(e) For each deviation from an emission limit, operating limit, and monitoring requirement in this subpart occurring at an affected source where you are using a CMS to comply with that emission limit or operating limit, you must include the information required in paragraphs (e)(1) through (12) of this section. This includes any deviations from your site-specific monitoring plan as required in § 63.7505(d).

(1) The date and time that each deviation 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.

(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) An analysis of the total duration of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of CMS's 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.

(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 part 70 or part 71 of this chapter must report all deviations as defined in this subpart in the semiannual monitoring report required by § 70.6(a)(3)(iii)(A) or § 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 § 70.6(a)(3)(iii)(A) or § 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 delegated authority.

(g) [Reserved]

(h) As of January 1, 2012 and within 60 days after the date of completing each performance test, as defined in § 63.2, conducted to demonstrate compliance with this subpart, you must submit relative accuracy test audit (*i.e.*, reference method) data and performance test (*i.e.*, compliance test) data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/ert tool.html/*) or other compatible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

§ 63.7555 What records must I keep?

(a) You must keep records according to paragraphs (a)(1) and (2) 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) Records of performance tests, fuel analyses, or other compliance demonstrations and performance evaluations as required in § 63.10(b)(2)(viii).

(b) For each CEMS, COMS, and continuous monitoring system you must keep records according to paragraphs (b)(1) through (5) of this section.

(1) Records described in § 63.10(b)(2)(vii) 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.

(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, pH, and operating load, to show continuous compliance with each emission limit and operating limit that applies to you.

(d) For each boiler or process heater subject to an emission limit in Table 1, 2 or 12 to this subpart, you must also keep the applicable records in paragraphs (d)(1) through (8) 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) If you combust non-hazardous secondary materials that have been determined not to be solid waste pursuant to § 41.3(b)(1), you must keep a record which documents how the secondary material meets each of the legitimacy criteria. If you combust a fuel that has been processed from a discarded non-hazardous secondary material pursuant to § 241.3(b)(4), you must keep records as to how the operations that produced the fuel satisfies the definition of processing in § 241.2. If the fuel received a non-waste determination pursuant to the petition process submitted under § 241.3(c), you must keep a record that documents how the fuel satisfies the requirements of the petition process.

(3) You must keep records of monthly hours of operation by each boiler or process heater that meets the definition of limited-use boiler or process heater.

(4) A copy of all calculations and supporting documentation of maximum chlorine fuel input, using Equation 7 of § 63.7530, that were done to demonstrate continuous compliance with the hydrogen chloride 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 hydrogen chloride emission rates, using Equation 10 of § 63.7530, that were done to demonstrate compliance with the hydrogen chloride emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum chlorine fuel input or hydrogen chloride 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 hydrogen chloride emission rate, for each boiler and process heater.

(5) A copy of all calculations and supporting documentation of maximum mercury fuel input, using Equation 8 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.

(6) If, consistent with § 63.7515(b) and (c), you choose to stack test less frequently than annually, you must keep annual records that document that your emissions in the previous stack test(s) were less than 75 percent of the applicable emission limit, and document that there was no change in source operations including fuel composition and operation of air pollution control equipment that would cause emissions of the relevant pollutant to increase within the past year.

(7) Records of the occurrence and duration of each malfunction of the boiler or process heater, or of the associated air pollution control and monitoring equipment.

(8) Records of actions taken during periods of malfunction to minimize emissions in accordance with the

general duty to minimize emissions in § 63.7500(a)(3), including corrective actions to restore the malfunctioning boiler or process heater, air pollution control, or monitoring equipment to its normal or usual manner of operation.

(e) If you elect to average emissions consistent with § 63.7522, you must additionally keep a copy of the emission averaging implementation plan required in § 63.7522(g), all calculations required under § 63.7522, including monthly records of heat input or steam generation, as applicable, and monitoring records consistent with § 63.7541.

(f) If you elect to use emission credits from energy conservation measures to demonstrate compliance according to § 63.7533, you must keep a copy of the Implementation Plan required in § 63.7533(d) and copies of all data and calculations used to establish credits according to § 63.7533(b), (c), and (f).

(g) If you elected to demonstrate that the unit meets the specifications for hydrogen sulfide and mercury for the other gas 1 subcategory and you cannot submit a signed certification under § 63.7545(g) because the constituents could exceed the specifications, you must maintain monthly records of the calculations and results of the fuel specifications for mercury and hydrogen sulfide in Table 6.

(h) If you operate a unit designed to burn natural gas, refinery gas, or other gas 1 fuel that is subject to this subpart, and you use an alternative fuel other than natural gas, refinery gas, or other gas 1 fuel, you must keep records of the total hours per calendar year that alternative fuel is burned.

§ 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, or they must be accessible from on site (for example, through a computer network), 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 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 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, 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, and alternative analytical methods requested under § 63.7521(b)(2).

(4) Approval of major change to monitoring under § 63.8(f) and as defined in § 63.90, and approval of alternative operating parameters under § 63.7500(a)(2) and § 63.7522(g)(2).

(5) Approval of major change to recordkeeping and reporting under § 63.10(e) and as defined in § 63.90.

§ 63.7575 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act, in § 63.2 (the General Provisions), and in this section as follows:

Affirmative defense means, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.

Annual heat input means the heat input for the 12 months preceding the compliance demonstration.

Bag leak detection system means a group of instruments that are 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.

Benchmarking means a process of comparison against standard or average.

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

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 annual gas volume 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. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled. A device combusting solid waste, as defined in § 241.3, is not a boiler unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Waste heat boilers are excluded from this definition.

Boiler system means the boiler and associated components, such as, the feed water system, the combustion air system, the fuel system (including burners), blowdown system, combustion control system, and energy consuming systems.

Calendar year means the period between January 1 and December 31, inclusive, for a given year.

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

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 steam and/or hot water.

Common stack means the exhaust of emissions from two or more affected units through a single flue. Affected units with a common stack may each have separate air pollution control systems located before the common stack, or may have a single air pollution control system located after the exhausts come together in a single flue.

Cost-effective energy conservation measure means a measure that is implemented to improve the energy efficiency of the boiler or facility that has a payback (return of investment) period of 2 years or less.

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; or

(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.

(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.

Dioxins/furans means tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans.

Distillate oil means fuel oils, including recycled oils, that comply with the specifications for fuel oil numbers 1 and 2, as defined by ASTM D396 (incorporated by reference, see § 63.14).

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. A dry scrubber is a dry control system.

Dutch oven means a unit having a refractory-walled cell connected to a conventional boiler setting. Fuel materials are introduced through an opening in the roof of the Dutch oven and burn in a pile on its floor.

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 (ESP) 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. An electrostatic precipitator is usually a dry control system.

Emission credit means emission reductions above those required by this subpart. Emission credits generated may be used to comply with the emissions limits. Credits may come from pollution prevention projects that result in reduced fuel use by affected units. Shutdowns cannot be used to generate credits.

Energy assessment means the following only as this term is used in Table 3 to this subpart.

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

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

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

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

Energy use system includes, but is not limited to, process heating; compressed air systems; machine drive (motors, pumps, fans); process cooling; facility heating, ventilation, and air-conditioning systems; hot heater systems; building envelop; and lighting.

Equivalent means the following only as this term is used in Table 6 to this subpart:

(1) An equivalent sample collection procedure means a published voluntary consensus standard or practice (VCS) or EPA method that includes collection of a minimum of three composite fuel samples, with each composite consisting of a minimum of three increments collected at approximately equal intervals over the test period.

(2) An equivalent sample compositing procedure means a published VCS or EPA method to systematically mix and obtain a representative subsample (part) of the composite sample.

(3) An equivalent sample preparation procedure means a published VCS or EPA method that: Clearly states that the standard, practice or method is appropriate for the pollutant and the fuel matrix; or is cited as an appropriate sample preparation standard, practice or method for the pollutant in the chosen VCS or EPA determinative or analytical method.

(4) An equivalent procedure for determining heat content means a published VCS or EPA method to obtain gross calorific (or higher heating) value.

(5) An equivalent procedure for determining fuel moisture content means a published VCS or EPA method to obtain moisture content. If the sample analysis plan calls for determining metals (especially the mercury, selenium, or arsenic) using an aliquot of the dried sample, then the drying

temperature must be modified to prevent vaporizing these metals. On the other hand, if metals analysis is done on an "as received" basis, a separate aliquot can be dried to determine moisture content and the metals concentration mathematically adjusted to a dry basis.

(6) An equivalent pollutant (mercury, hydrogen chloride, hydrogen sulfide) determinative or analytical procedure means a published VCS or EPA method that clearly states that the standard, practice, or method is appropriate for the pollutant and the fuel matrix and has a published detection limit equal or lower than the methods listed in Table 6 to this subpart for the same purpose.

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. A fabric filter is a dry control system.

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.

Fluidized bed boiler means a boiler utilizing a fluidized bed combustion process.

Fluidized bed combustion means a process where a fuel is burned in a bed of granulated particles, which are maintained in a mobile suspension by the forward flow of air and combustion products.

Fuel cell means a boiler type in which the fuel is dropped onto suspended fixed grates and is fired in a pile. The refractory-lined fuel cell uses combustion air preheating and positioning of secondary and tertiary air injection ports to improve boiler efficiency.

Fuel type means each category of fuels that share a common name or classification. Examples include, but are not limited to, bituminous coal, sub-bituminous coal, lignite, anthracite, biomass, residual oil. Individual fuel types received from different suppliers are not considered new fuel types.

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.

Hourly average means the arithmetic average of at least four CMS data values representing the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CMS calibration, quality assurance, or maintenance activities are being performed.

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 degrees Fahrenheit (99 degrees Celsius). *Hot water heater* also means a tankless unit that provides on demand hot water.

Hybrid suspension grate boiler means a boiler designed with air distributors to spread the fuel material over the entire width and depth of the boiler combustion zone. The drying and much of the combustion of the fuel takes place in suspension, and the combustion is completed on the grate or floor of the boiler.

Industrial boiler means a boiler used in manufacturing, processing, mining, and refining or any other industry to provide steam and/or hot water.

Limited-use boiler or process heater means any boiler or process heater that burns any amount of solid, liquid, or gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and has a federally enforceable limit of no more than 876 hours per year of operation.

Liquid fuel subcategory includes any boiler or process heater of any design that burns more than 10 percent liquid fuel and less than 10 percent solid fuel, based on the total annual heat input to the unit.

Liquid fuel includes, but is not limited to, distillate oil, residual oil, on-spec used oil, and biodiesel.

Load fraction means the actual heat input of the boiler or process heater divided by the average operating load determined according to Table 7 to this subpart.

Metal process furnaces include natural gas-fired annealing furnaces, preheat furnaces, reheat furnaces, aging furnaces, heat treat furnaces, and homogenizing furnaces.

Million Btu (MMBtu) means one million British thermal units.

Minimum activated carbon injection rate means load fraction (percent) multiplied by the lowest hourly average activated carbon injection rate measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits.

Minimum pressure drop means the lowest hourly 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 the lowest hourly average sorbent liquid pH measured at the inlet to 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 liquid flow rate means the lowest hourly average liquid flow rate (*e.g.,* to the PM scrubber or to the acid gas scrubber) measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum scrubber pressure drop means the lowest hourly average scrubber pressure drop measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum sorbent injection rate means load fraction (percent) multiplied by the lowest hourly average sorbent injection rate for each sorbent measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits.

Minimum total secondary electric power means the lowest hourly average total secondary electric power determined from the values of secondary voltage and secondary current 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 in ASTM D1835 (incorporated by reference, *see* § 63.14); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 34 and 43 mega joules (MJ) per dry standard cubic

meter (910 and 1,150 Btu per dry standard cubic foot); or

(4) Propane or propane derived synthetic natural gas. Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure C_3H_8.

Opacity means the degree to which emissions reduce the transmission of light and obscure the view of an object in the background.

Operating day means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the boiler or process heater unit. It is not necessary for fuel to be combusted for the entire 24-hour period.

Other gas 1 fuel means a gaseous fuel that is not natural gas or refinery gas and does not exceed the maximum concentration of 40 micrograms/cubic meters of mercury and 4 parts per million, by volume, of hydrogen sulfide.

Particulate matter (PM) means any finely divided solid or liquid material, other than uncombined water, as measured by the test methods specified under this subpart, or an approved 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. The act of entering into a contractual agreement with a supplier of natural gas established for curtailment purposes does not constitute a reason that is under the control of a facility for the purposes of this definition. 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, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not come into direct contact with process materials. A device combusting solid waste, as defined in § 241.3, is not a process heater unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Process heaters do not include units used for comfort heat or space heat, food preparation for on-site consumption, or autoclaves.

Pulverized coal boiler means a boiler in which pulverized coal or other solid fossil fuel is introduced into an air stream that carries the coal to the combustion chamber of the boiler where it is fired in suspension.

Qualified energy assessor means:

(1) someone who has demonstrated capabilities to evaluate a set of the typical energy savings opportunities available in opportunity areas for steam generation and major energy using systems, including, but not limited to:

(i) Boiler combustion management.

(ii) Boiler thermal energy recovery, including

(A) Conventional feed water economizer,

(B) Conventional combustion air preheater, and

(C) Condensing economizer.

(iii) Boiler blowdown thermal energy recovery.

(iv) Primary energy resource selection, including

(A) Fuel (primary energy source) switching, and

(B) Applied steam energy versus direct-fired energy versus electricity.

(v) Insulation issues.

(vi) Steam trap and steam leak management.

(vi) Condensate recovery.

(viii) Steam end-use management.

(2) Capabilities and knowledge includes, but is not limited to:

(i) Background, experience, and recognized abilities to perform the assessment activities, data analysis, and report preparation.

(ii) Familiarity with operating and maintenance practices for steam or process heating systems.

(iii) Additional potential steam system improvement opportunities including improving steam turbine operations and reducing steam demand.

(iv) Additional process heating system opportunities including effective utilization of waste heat and use of proper process heating methods.

(v) Boiler-steam turbine cogeneration systems.

(vi) Industry specific steam end-use systems.

Refinery gas means any gas that is generated at a petroleum refinery and is combusted. Refinery gas includes natural gas when the natural gas is combined and combusted in any proportion with a gas generated at a refinery. Refinery gas includes gases generated from other facilities when that gas is combined and combusted in any proportion with gas generated at a refinery.

Residual oil means crude oil, and all fuel oil numbers 4, 5 and 6, as defined in ASTM D396–10 (incorporated by reference, see § 63.14(b)).

Responsible official means responsible official as defined in § 70.2.

Solid fossil fuel includes, and is not limited to, coal, coke, petroleum coke, and tire derived fuel.

Solid fuel means any solid fossil fuel or biomass or bio-based solid fuel.

Steam output means (1) for a boiler that produces steam for process or heating only (no power generation), the energy content in terms of MMBtu of the boiler steam output, and (2) for a boiler that cogenerates process steam and electricity (also known as combined heat and power (CHP)), the total energy output, which is the sum of the energy content of the steam exiting the turbine and sent to process in MMBtu and the energy of the electricity generated converted to MMBtu at a rate of 10,000 Btu per kilowatt-hour generated (10 MMBtu per megawatt-hour).

Stoker means a unit consisting of a mechanically operated fuel feeding mechanism, a stationary or moving grate to support the burning of fuel and admit under-grate air to the fuel, an overfire air system to complete combustion, and an ash discharge system. This definition of stoker includes air swept stokers. There are two general types of stokers: Underfeed and overfeed. Overfeed stokers include mass feed and spreader stokers.

Suspension boiler means a unit designed to feed the fuel by means of fuel distributors. The distributors inject air at the point where the fuel is introduced into the boiler in order to spread the fuel material over the boiler width. The drying (and much of the combustion) occurs while the material is suspended in air. The combustion of the fuel material is completed on a grate or floor below. Suspension boilers almost universally are designed to have high heat release rates to dry quickly the wet fuel as it is blown into the boilers.

Temporary boiler means any gaseous or liquid fuel boiler that is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A boiler is not a temporary boiler if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

(2) The boiler or a replacement remains at a location for more than 12 consecutive months. Any temporary boiler that replaces a temporary boiler at a location and performs the same or similar function will be included in calculating the consecutive time period.

(3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility

for at least 2 years, and operates at that facility for at least 3 months each year.

(4) The equipment is moved from one location to another in an attempt to circumvent the residence time requirements of this definition.

Tune-up means adjustments made to a boiler in accordance with procedures supplied by the manufacturer (or an approved specialist) to optimize the combustion efficiency.

Unit designed to burn biomass/bio-based solid subcategory includes any boiler or process heater that burns at least 10 percent biomass or bio-based solids on an annual heat input basis in combination with solid fossil fuels, liquid fuels, or gaseous fuels.

Unit designed to burn coal/solid fossil fuel subcategory includes any boiler or process heater that burns any coal or other solid fossil fuel alone or at least 10 percent coal or other solid fossil fuel on an annual heat input basis in combination with liquid fuels, gaseous fuels, or less than 10 percent biomass and bio-based solids on an annual heat input basis.

Unit designed to burn gas 1 subcategory includes any boiler or process heater that burns only natural gas, refinery gas, and/or other gas 1 fuels; with the exception of liquid fuels burned for periodic testing not to exceed a combined total of 48 hours during any calendar year, or during periods of gas curtailment and gas supply emergencies.

Unit designed to burn gas 2 (other) subcategory includes any boiler or process heater that is not in the unit designed to burn gas 1 subcategory and burns any gaseous fuels either alone or in combination with less than 10 percent coal/solid fossil fuel, less than 10 percent biomass/bio-based solid fuel, and less than 10 percent liquid fuels on an annual heat input basis.

Unit designed to burn liquid subcategory includes any boiler or process heater that burns any liquid fuel, but less than 10 percent coal/solid fossil fuel and less than 10 percent biomass/bio-based solid fuel on an annual heat input basis, either alone or in combination with gaseous fuels. Gaseous fuel boilers and process heaters that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year or during periods of maintenance, operator training, or testing of liquid fuel, not to exceed a combined total of 48 hours during any calendar year are not included in this definition. Gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply emergencies of any duration are also not included in this definition.

Unit designed to burn liquid fuel that is a non-continental unit means an industrial, commercial, or institutional boiler or process heater designed to burn liquid fuel located in the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Unit designed to burn solid fuel subcategory means any boiler or process heater that burns any solid fuel alone or at least 10 percent solid fuel on an annual heat input basis in combination with liquid fuels or gaseous fuels.

Voluntary Consensus Standards or VCS mean technical standards (*e.g.,* materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. EPA/Office of Air Quality Planning and Standards, by precedent, has only used VCS that are written in English. Examples of VCS bodies are: American Society of Testing and Materials (ASTM 100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428–B2959, (800) 262–1373, *http://www.astm.org*), American Society of Mechanical Engineers (ASME ASME, Three Park Avenue, New York, NY 10016–5990, (800) 843–2763, *http://www.asme.org*), International Standards Organization (ISO 1, ch. de la Voie-Creuse, Case postale 56, CH–1211 Geneva 20, Switzerland, +41 22 749 01 11, *http://www.iso.org/iso/home.htm*), Standards Australia (AS Level 10, The Exchange Centre, 20 Bridge Street, Sydney, GPO Box 476, Sydney NSW 2001, + 61 2 9237 6171 *http://www.stadards.org.au*), British Standards Institution (BSI, 389 Chiswick High Road, London, W4 4AL, United Kingdom, +44 (0)20 8996 9001, *http://www.bsigroup.com*), Canadian Standards Association (CSA 5060 Spectrum Way, Suite 100, Mississauga, Ontario L4W 5N6, Canada, 800–463–6727, *http://www.csa.ca*), European Committee for Standardization (CEN CENELEC Management Centre Avenue Marnix 17 B–1000 Brussels, Belgium +32 2 550 08 11, *http://www.cen.eu/cen*), and German Engineering Standards (VDI VDI Guidelines Department, P.O. Box 10 11 39 40002, Duesseldorf, Germany, +49 211 6214–230, *http://www.vdi.eu*). The types of standards that are not considered VCS are standards developed by: The United States, *e.g.,* California (CARB) and Texas (TCEQ); industry groups, such as American Petroleum Institute (API), Gas Processors Association (GPA), and Gas Research Institute (GRI); and other branches of the U.S. government, *e.g.,* Department of Defense (DOD) and Department of Transportation (DOT). This does not preclude EPA from using standards developed by groups that are not VCS bodies within their rule. When this occurs, EPA has done searches and reviews for VCS equivalent to these non-EPA methods.

Waste heat boiler means a device that recovers normally unused energy and converts it to usable heat. Waste heat boilers are also referred to as heat recovery steam generators.

Waste heat process heater means an enclosed device that recovers normally unused energy and converts it to usable heat. Waste heat process heaters are also referred to as recuperative process heaters.

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 or to absorb and neutralize acid gases, such as hydrogen chloride. A wet scrubber creates an aqueous stream or slurry as a byproduct of the emissions control process.

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 Clean Air Act.

Tables to Subpart DDDDD of Part 63

As stated in § 63.7500, you must comply with the following applicable emission limits:

TABLE 1 TO SUBPART DDDDD OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS[a]

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Or the emissions must not exceed the following output-based limits (lb per MMBtu of steam output) . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel.	a. Particulate Matter	0.0011 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr).	0.0011; (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr).	Collect a minimum of 3 dscm per run.
	b. Hydrogen Chloride	0.0022 lb per MMBtu of heat input.	0.0021	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 60 liters per run.
	c. Mercury	3.5E–06 lb per MMBtu of heat input.	3.4E–06	For M29, collect a minimum of 1 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b] collect a minimum of 2 dscm.
2. Units designed to burn pulverized coal/solid fossil fuel.	a. Carbon monoxide (CO)	12 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.01	1 hr minimum sampling time, use a span value of 30 ppmv.
	b. Dioxins/Furans	0.003 ng/dscm (TEQ) corrected to 7 percent oxygen.	2.8E–12 (TEQ)	Collect a minimum of 4 dscm per run.
3. Stokers designed to burn coal/solid fossil fuel.	a. CO	6 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.005	1 hr minimum sampling time, use a span value of 20 ppmv.
	b. Dioxins/Furans	0.003 ng/dscm (TEQ) corrected to 7 percent oxygen.	2.8E–12 (TEQ)	Collect a minimum of 4 dscm per run.
4. Fluidized bed units designed to burn coal/solid fossil fuel.	a. CO	18 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.02	1 hr minimum sampling time, use a span value of 40 ppmv.
	b. Dioxins/Furans	0.002 ng/dscm (TEQ) corrected to 7 percent oxygen.	1.8E–12 (TEQ)	Collect a minimum of 4 dscm per run.
5. Stokers designed to burn biomass/bio-based solids.	a. CO	160 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.13	1 hr minimum sampling time, use a span value of 400 ppmv.
	b. Dioxins/Furans	0.005 ng/dscm (TEQ) corrected to 7 percent oxygen.	4.4E–12 (TEQ)	Collect a minimum of 4 dscm per run.
6. Fluidized bed units designed to burn biomass/bio-based solids.	a. CO	260 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.18	1 hr minimum sampling time, use a span value of 500 ppmv.
	b. Dioxins/Furans	0.02 ng/dscm (TEQ) corrected to 7 percent oxygen.	1.8E–11 (TEQ)	Collect a minimum of 4 dscm per run.
7. Suspension burners/Dutch Ovens designed to burn biomass/bio-based solids.	a. CO	470 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.45	1 hr minimum sampling time, use a span value of 1000 ppmv.
	b. Dioxins/Furans	0.2 ng/dscm (TEQ) corrected to 7 percent oxygen.	1.8E–10 (TEQ)	Collect a minimum of 4 dscm per run.
8. Fuel cells designed to burn biomass/bio-based solids.	a. CO	470 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.23	1 hr minimum sampling time, use a span value of 1000 ppmv.
	b. Dioxins/Furans	0.003 ng/dscm (TEQ) corrected to 7 percent oxygen.	2.86E–12 (TEQ)	Collect a minimum of 4 dscm per run.
9. Hybrid suspension/grate units designed to burn biomass/bio-based solids.	a. CO	1,500 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.84	1 hr minimum sampling time, use a span value of 3000 ppmv.

TABLE 1 TO SUBPART DDDDD OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS [a]—Continued

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Or the emissions must not exceed the following output-based limits (lb per MMBtu of steam output) . . .	Using this specified sampling volume or test run duration . . .
	b. Dioxins/Furans	0.2 ng/dscm (TEQ) corrected to 7 percent oxygen.	1.8E–10 (TEQ)	Collect a minimum of 4 dscm per run.
10. Units designed to burn liquid fuel.	a. Particulate Matter	0.0013 lb per MMBtu of heat input (30-day rolling average for residual oil-fired units 250 MMBtu/hr or greater, 3-run average for other units).	0.001; (30-day rolling average for residual oil-fired units 250 MMBtu/hr or greater, 3-run average for other units).	Collect a minimum of 3 dscm per run.
	b. Hydrogen Chloride	0.00033 lb per MMBtu of heat input.	0.0003	For M26A: Collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.
	c. Mercury	2.1E–07 lb per MMBtu of heat input.	0.2E–06	Collect enough volume to meet an in-stack detection limit data quality objective of 0.10 ug/dscm.
	d. CO	3 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.0026	1 hr minimum sampling time, use a span value of 3 ppmv.
	e. Dioxins/Furans	0.002 ng/dscm (TEQ) corrected to 7 percent oxygen.	4.6E–12 (TEQ)	Collect a minimum of 4 dscm per run.
11. Units designed to burn liquid fuel located in non-continental States and territories.	a. Particulate Matter	0.0013 lb per MMBtu of heat input (30-day rolling average for residual oil-fired units 250 MMBtu/hr or greater, 3-run average for other units).	0.001; (30-day rolling average for residual oil-fired units 250 MMBtu/hr or greater, 3-run average for other units).	Collect a minimum of 3 dscm per run.
	b. Hydrogen Chloride	0.00033 lb per MMBtu of heat input.	0.0003	For M26A: Collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.
	c. Mercury	7.8E–07 lb per MMBtu of heat input.	8.0E–07	For M29, collect a minimum of 3 dscm per run; for M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 3 dscm.
	d. CO	51 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.043	1 hr minimum sampling time, use a span value of 100 ppmv.
	e. Dioxins/Furans	0.002 ng/dscm (TEQ) corrected to 7 percent oxygen.	4.6E–12(TEQ)	Collect a minimum of 3 dscm per run.
12. Units designed to burn gas 2 (other) gases.	a. Particulate Matter	0.0067 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr).	.004; (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr).	Collect a minimum of 1 dscm per run.
	b. Hydrogen Chloride	0.0017 lb per MMBtu of heat input.	.003	For M26A, Collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.

TABLE 1 TO SUBPART DDDDD OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS [a]—Continued

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Or the emissions must not exceed the following output-based limits (lb per MMBtu of steam output) . . .	Using this specified sampling volume or test run duration . . .
	c. Mercury	7.9E–06 lb per MMBtu of heat input.	2.0E–07	For M29, collect a minimum of 1 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 2 dscm.
	d. CO	3 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.002	1 hr minimum sampling time, use a span value of 10 ppmv.
	e. Dioxins/Furans	0.08 ng/dscm (TEQ) corrected to 7 percent oxygen.	4.1E–12 (TEQ)	Collect a minimum of 4 dscm per run

[a] If your affected source is a new or reconstructed affected source that commenced construction or reconstruction after June 4, 2010, and before May 20, 2011, you may comply with the emission limits in Table 12 to this subpart until March 21, 2014. On and after March 21, 2014, you must comply with the emission limits in Table 1 to this subpart.

[b] Incorporated by reference, see § 63.14.

As stated in § 63.7500, you must comply with the following applicable emission limits:

TABLE 2 TO SUBPART DDDDD OF PART 63—EMISSION LIMITS FOR EXISTING BOILERS AND PROCESS HEATERS

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	The emissions must not exceed the following output-based limits (lb per MMBtu of steam output) . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel.	a. Particulate Matter	0.039 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr).	0.038; (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr).	Collect a minimum of 1 dscm per run.
	b. Hydrogen Chloride	0.035 lb per MMBtu of heat input.	0.04	For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.
	c. Mercury	4.6E–06 lb per MMBtu of heat input.	4.5E–06	For M29, collect a minimum of 1 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [a] collect a minimum of 2 dscm.
2. Pulverized coal units designed to burn pulverized coal/solid fossil fuel.	a. CO	160 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.14	1 hr minimum sampling time, use a span value of 300 ppmv.
	b. Dioxins/Furans	0.004 ng/dscm (TEQ) corrected to 7 percent oxygen.	3.7E–12 (TEQ)	Collect a minimum of 4 dscm per run.
3. Stokers designed to burn coal/solid fossil fuel.	a. CO	270 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.25	1 hr minimum sampling time, use a span value of 500 ppmv.
	b. Dioxins/Furans	0.003 ng/dscm (TEQ) corrected to 7 percent oxygen.	2.8E–12 (TEQ)	Collect a minimum of 4 dscm per run.

TABLE 2 TO SUBPART DDDDD OF PART 63—EMISSION LIMITS FOR EXISTING BOILERS AND PROCESS HEATERS—Continued

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	The emissions must not exceed the following output-based limits (lb per MMBtu of steam output) . . .	Using this specified sampling volume or test run duration . . .
4. Fluidized bed units designed to burn coal/solid fossil fuel.	a. CO	82 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.08	1 hr minimum sampling time, use a span value of 200 ppmv
	b. Dioxins/Furans	0.002 ng/dscm (TEQ) corrected to 7 percent oxygen.	1.8E–12 (TEQ)	Collect a minimum of 4 dscm per run.
5. Stokers designed to burn biomass/bio-based solid.	a. CO	490 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.35	1 hr minimum sampling time, use a span value of 1000 ppmv.
	b. Dioxins/Furans	0.005 ng/dscm (TEQ) corrected to 7 percent oxygen.	4.4E–12 (TEQ)	Collect a minimum of 4 dscm per run.
6. Fluidized bed units designed to burn biomass/bio-based solid.	a. CO	430 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.28	1 hr minimum sampling time, use a span value of 850 ppmv.
	b. Dioxins/Furans	0.02 ng/dscm (TEQ) corrected to 7 percent oxygen.	1.8E–11(TEQ)	Collect a minimum of 4 dscm per run.
7. Suspension burners/Dutch Ovens designed to burn biomass/bio-based solid.	a. CO	470 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.45	1 hr minimum sampling time, use a span value of 1000 ppmv.
	b. Dioxins/Furans	0.2 ng/dscm (TEQ) corrected to 7 percent oxygen.	1.8E–10 (TEQ)	Collect a minimum of 4 dscm per run.
8. Fuel cells designed to burn biomass/bio-based solid.	a. CO	690 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.34	1 hr minimum sampling time, use a span value of 1300 ppmv.
	b. Dioxins/Furans	4 ng/dscm (TEQ) corrected to 7 percent oxygen.	3.5E–09 (TEQ)	Collect a minimum of 4 dscm per run.
9. Hybrid suspension/grate units designed to burn biomass/bio-based solid.	a. CO	3,500 ppm by volume on a dry basis corrected to 3 percent oxygen.	2.0	1 hr minimum sampling time, use a span value of 7000 ppmv.
	b. Dioxins/Furans	0.2 ng/dscm (TEQ) corrected to 7 percent oxygen.	1.8E–10 (TEQ)	Collect a minimum of 4 dscm per run.
10. Units designed to burn liquid fuel.	a. Particulate Matter	0.0075 lb per MMBtu of heat input (30-day rolling average for residual oil-fired units 250 MMBtu/hr or greater, 3-run average for other units).	0.0073; (30-day rolling average for residual oil-fired units 250 MMBtu/hr or greater, 3-run average for other units).	Collect a minimum of 1 dscm per run.
	b. Hydrogen Chloride	0.00033 lb per MMBtu of heat input.	0.0003	For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 200 liters per run.
	c. Mercury	3.5E–06 lb per MMBtu of heat input.	3.3E–06	For M29, collect a minimum of 1 dscm per run; for M30A or M30B collect a minimum sample as specified in the method, for ASTM D6784 [a] collect a minimum of 2 dscm.
	d. CO	10 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.0083	1 hr minimum sampling time, use a span value of 20 ppmv.
	e. Dioxins/Furans	4 ng/dscm (TEQ) corrected to 7 percent oxygen.	9.2E–09 (TEQ)	Collect a minimum of 1 dscm per run.

TABLE 2 TO SUBPART DDDDD OF PART 63—EMISSION LIMITS FOR EXISTING BOILERS AND PROCESS HEATERS—Continued

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	The emissions must not exceed the following output-based limits (lb per MMBtu of steam output) . . .	Using this specified sampling volume or test run duration . . .
11. Units designed to burn liquid fuel located in non-continental States and territories.	a. Particulate Matter	0.0075 lb per MMBtu of heat input (30-day rolling average for residual oil-fired units 250 MMBtu/hr or greater, 3-run average for other units).	0.0073; (30-day rolling average for residual oil-fired units 250 MMBtu/hr or greater, 3-run average for other units).	Collect a minimum of 1 dscm per run.
	b. Hydrogen Chloride	0.00033 lb per MMBtu of heat input.	0.0003	For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 200 liters per run.
	c. Mercury	7.8E–07 lb per MMBtu of heat input.	8.0E–07	For M29, collect a minimum of 1 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [a] collect a minimum of 2 dscm.
	d. CO	160 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.13	1 hr minimum sampling time, use a span value of 300 ppmv.
	e. Dioxins/Furans	4 ng/dscm (TEQ) corrected to 7 percent oxygen.	9.2E–09 (TEQ)	Collect a minimum of 1 dscm per run.
12. Units designed to burn gas 2 (other) gases.	a. Particulate Matter	0.043 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr).	0.026; (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr).	Collect a minimum of 1 dscm per run.
	b. Hydrogen Chloride	0.0017 lb per MMBtu of heat input.	0.001	For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.
	c. Mercury	1.3E–05 lb per MMBtu of heat input.	7.8E–06	For M29, collect a minimum of 1 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [a] collect a minimum of 2 dscm.
	d. CO	9 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.005	1 hr minimum sampling time, use a span value of 20 ppmv.
	e. Dioxins/Furans	0.08 ng/dscm (TEQ) corrected to 7 percent oxygen.	3.9E–11 (TEQ)	Collect a minimum of 4 dscm per run.

[a] Incorporated by reference, see § 63.14.

As stated in § 63.7500, you must comply with the following applicable work practice standards:

TABLE 3 TO SUBPART DDDDD OF PART 63—WORK PRACTICE STANDARDS

If your unit is . . .	You must meet the following . . .
1. A new or existing boiler or process heater with heat input capacity of less than 10 million Btu per hour or a limited use boiler or process heater.	Conduct a tune-up of the boiler or process heater biennially as specified in § 63.7540.

TABLE 3 TO SUBPART DDDDD OF PART 63—WORK PRACTICE STANDARDS—Continued

If your unit is . . .	You must meet the following . . .
2. A new or existing boiler or process heater in either the Gas 1 or Metal Process Furnace subcategory with heat input capacity of 10 million Btu per hour or greater.	Conduct a tune-up of the boiler or process heater annually as specified in § 63.7540.
3. An existing boiler or process heater located at a major source facility	Must have a one-time energy assessment performed on the major source facility by qualified energy assessor. An energy assessment completed on or after January 1, 2008, that meets or is amended to meet the energy assessment requirements in this table, satisfies the energy assessment requirement. The energy assessment must include: a. A visual inspection of the boiler or process heater system. b. An evaluation of operating characteristics of the facility, specifications of energy using systems, operating and maintenance procedures, and unusual operating constraints, c. An inventory of major energy consuming systems, d. A review of available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage, e. A review of the facility's energy management practices and provide recommendations for improvements consistent with the definition of energy management practices, f. A list of major energy conservation measures, g. A list of the energy savings potential of the energy conservation measures identified, and h. A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments.
4. An existing or new unit subject to emission limits in Tables 1, 2, or 12 of this subpart..	Minimize the unit's startup and shutdown periods following the manufacturer's recommended procedures. If manufacturer's recommended procedures are not available, you must follow recommended procedures for a unit of similar design for which manufacturer's recommended procedures are available.

As stated in § 63.7500, you must comply with the applicable operating limits:

TABLE 4 TO SUBPART DDDDD OF PART 63—OPERATING LIMITS FOR BOILERS AND PROCESS HEATERS

If you demonstrate compliance using . . .	You must meet these operating limits . . .
1. Wet PM scrubber control	Maintain the 12-hour block average pressure drop and the 12-hour block average liquid flow rate at or above the lowest 1-hour average pressure drop and the lowest 1-hour average liquid flow rate, respectively, measured during the most recent performance test demonstrating compliance with the PM emission limitation according to § 63.7530(b) and Table 7 to this subpart.
2. Wet acid gas (HCl) scrubber control	Maintain the 12-hour block average effluent pH at or above the lowest 1-hour average pH and the 12-hour block average liquid flow rate at or above the lowest 1-hour average liquid flow rate measured during the most recent performance test demonstrating compliance with the HCl emission limitation according to § 63.7530(b) and Table 7 to this subpart.
3. Fabric filter control on units not required to install and operate a PM CEMS.	a. Maintain opacity to less than or equal to 10 percent opacity (daily block average); or b. 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.
4. Electrostatic precipitator control on units not required to install and operate a PM CEMS.	a. This option is for boilers and process heaters that operate dry control systems (*i.e.,* an ESP without a wet scrubber). Existing and new boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (daily block average); or b. This option is only for boilers and process heaters not subject to PM CEMS or continuous compliance with an opacity limit (i.e., COMS). Maintain the minimum total secondary electric power input of the electrostatic precipitator at or above the operating limits established during the performance test according to § 63.7530(b) and Table 7 to this subpart.
5. Dry scrubber or carbon injection control	Maintain the minimum sorbent or carbon injection rate as defined in § 63.7575 of this subpart.

TABLE 4 TO SUBPART DDDDD OF PART 63—OPERATING LIMITS FOR BOILERS AND PROCESS HEATERS—Continued

If you demonstrate compliance using . . .	You must meet these operating limits . . .
6. Any other add-on air pollution control type on units not required to install and operate a PM CEMS.	This option is for boilers and process heaters that operate dry control systems. Existing and new boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (daily block average).
7. Fuel analysis	Maintain the fuel type or fuel mixture such that the applicable emission rates calculated according to § 63.7530(c)(1), (2) and/or (3) is less than the applicable emission limits.
8. Performance testing	For boilers and process heaters that demonstrate compliance with a performance test, maintain the operating load of each unit such that is does not exceed 110 percent of the average operating load recorded during the most recent performance test.
9. Continuous Oxygen Monitoring System	For boilers and process heaters subject to a carbon monoxide emission limit that demonstrate compliance with an O_2 CEMS as specified in § 63.7525(a), maintain the oxygen level of the stack gas such that it is not below the lowest hourly average oxygen concentration measured during the most recent CO performance test.

As stated in § 63.7520, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources:

TABLE 5 TO SUBPART DDDDD OF PART 63—PERFORMANCE TESTING REQUIREMENTS

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 at 40 CFR part 60, appendix A–1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas..	Method 2, 2F, or 2G at 40 CFR part 60, appendix A–1 or A–2 to part 60 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas.	Method 3A or 3B at 40 CFR part 60, appendix A–2 to part 60 of this chapter, or ANSI/ASME PTC 19.10–1981.[a]
	d. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A–3 of this chapter.
	e. Measure the particulate matter emission concentration.	Method 5 or 17 (positive pressure fabric filters must use Method 5D) at 40 CFR part 60, appendix A–3 or A–6 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology at 40 CFR part 60, appendix A–7 of this chapter.
2. Hydrogen chloride	a. Select sampling ports location and the number of traverse points.	Method 1 at 40 CFR part 60, appendix A–1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G at 40 CFR part 60, appendix A–2 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas.	Method 3A or 3B at 40 CFR part 60, appendix A–2 of this chapter, or ANSI/ASME PTC 19.10–1981.[a]
	d. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A–3 of this chapter.
	e. Measure the hydrogen chloride emission concentration.	Method 26 or 26A (M26 or M26A) at 40 CFR part 60, appendix A–8 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology at 40 CFR part 60, appendix A–7 of this chapter.
3. Mercury	a. Select sampling ports location and the number of traverse points.	Method 1 at 40 CFR part 60, appendix A–1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G at 40 CFR part 60, appendix A–1 or A–2 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas.	Method 3A or 3B at 40 CFR part 60, appendix A–1 of this chapter, or ANSI/ASME PTC 19.10–1981.[a]
	d. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A–3 of this chapter.
	e. Measure the mercury emission concentration	Method 29, 30A, or 30B (M29, M30A, or M30B) at 40 CFR part 60, appendix A–8 of this chapter or Method 101A at 40 CFR part 60, appendix B of this chapter, or ASTM Method D6784.[a]
	f. Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology at 40 CFR part 60, appendix A–7 of this chapter.
4. CO	a. Select the sampling ports location and the number of traverse points.	Method 1 at 40 CFR part 60, appendix A–1 of this chapter.

TABLE 5 TO SUBPART DDDDD OF PART 63—PERFORMANCE TESTING REQUIREMENTS—Continued

To conduct a performance test for the following pollutant...	You must...	Using...
	b. Determine oxygen concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A–3 of this chapter, or ASTM D6522–00 (Reapproved 2005), or ANSI/ASME PTC 19.10–1981.[a]
	c. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A–3 of this chapter.
	d. Measure the CO emission concentration	Method 10 at 40 CFR part 60, appendix A–4 of this chapter. Use a span value of 2 times the concentration of the applicable emission limit.
5. Dioxins/Furans	a. Select the sampling ports location and the number of traverse points.	Method 1 at 40 CFR part 60, appendix A–1 of this chapter.
	b. Determine oxygen concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A–3 of this chapter, or ASTM D6522–00 (Reapproved 2005),[a] or ANSI/ASME PTC 19.10–1981.[a]
	c. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A–3 of this chapter.
	d. Measure the dioxins/furans emission concentration	Method 23 at 40 CFR part 60, appendix A–7 of this chapter.
	e. Multiply the measured dioxins/furans emission concentration by the appropriate toxic equivalency factor.	Table 11 of this subpart.

[a] Incorporated by reference, see § 63.14.

As stated in § 63.7521, you must comply with the following requirements for fuel analysis testing for existing, new or reconstructed affected sources. However, equivalent methods (as defined in § 63.7575) may be used in lieu of the prescribed methods at the discretion of the source owner or operator:

TABLE 6 TO SUBPART DDDDD OF PART 63—FUEL ANALYSIS REQUIREMENTS

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/D2234M[a] (for coal) or ASTM D6323[a] (for biomass), or equivalent.
	b. Composite fuel samples	Procedure in § 63.7521(d) or equivalent.
	c. Prepare composited fuel samples	EPA SW–846–3050B[a] (for solid samples), EPA SW–846–3020A[a] (for liquid samples), ASTM D2013/D2013M[a] (for coal), ASTM D5198[a] (for biomass), or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865[a] (for coal) or ASTM E711[a] (for biomass), or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173[a] or ASTM E871,[a] or equivalent.
	f. Measure mercury concentration in fuel sample.	ASTM D6722[a] (for coal), EPA SW–846–7471B[a] (for solid samples), or EPA SW–846–7470A[a] (for liquid samples), or equivalent.
	g. Convert concentration into units of pounds of pollutant per MMBtu of heat content.	
2. Hydrogen Chloride	a. Collect fuel samples	Procedure in § 63.7521(c) or ASTM D2234/D2234M[a] (for coal) or ASTM D6323[a] (for biomass), or equivalent.
	b. Composite fuel samples	Procedure in § 63.7521(d) or equivalent.
	c. Prepare composited fuel samples	EPA SW–846–3050B[a] (for solid samples), EPA SW–846–3020A[a] (for liquid samples), ASTM D2013/D2013M[a] (for coal), or ASTM D5198[a] (for biomass), or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865[a] (for coal) or ASTM E711[a] (for biomass), or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173[a] or ASTM E871,[a] or equivalent.
	f. Measure chlorine concentration in fuel sample.	EPA SW–846–9250,[a] ASTM D6721[a] (for coal), or ASTM E776[a] (for biomass), or equivalent.
	g. Convert concentrations into units of pounds of pollutant per MMBtu of heat content.	
3. Mercury Fuel Specification for other gas 1 fuels.	a. Measure mercury concentration in the fuel sample.	ASTM D5954,[a] ASTM D6350,[a] ISO 6978–1:2003(E),[a] or ISO 6978–2:2003(E)[a], or equivalent.
	b. Convert concentration to unit of micrograms/cubic meter.	

TABLE 6 TO SUBPART DDDDD OF PART 63—FUEL ANALYSIS REQUIREMENTS—Continued

To conduct a fuel analysis for the following pollutant . . .	You must . . .	Using . . .
4. Hydrogen Sulfide Fuel Specification for other gas 1 fuels.	a. Measure total hydrogen sulfide b. Convert to ppm	ASTM D4084a or equivalent.

[a] Incorporated by reference, see § 63.14.

As stated in § 63.7520, you must comply with the following requirements for establishing operating limits:

TABLE 7 TO SUBPART DDDDD OF PART 63—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 or mercury.	a. Wet scrubber operating parameters.	i. Establish a site-specific minimum pressure drop and minimum flow rate operating limit according to § 63.7530(b).	(1) Data from the pressure drop and liquid flow rate monitors and the particulate matter or mercury performance test.	(a) You must collect pressure drop and liquid flow rate data every 15 minutes during the entire period of the performance tests; (b) Determine the lowest hourly average pressure drop and liquid flow rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.
	b. Electrostatic precipitator operating parameters (option only for units that operate wet scrubbers).	i. Establish a site-specific minimum total secondary electric power input according to § 63.7530(b).	(1) Data from the voltage and secondary amperage monitors during the particulate matter or mercury performance test.	(a) You must collect secondary voltage and secondary amperage for each ESP cell and calculate total secondary electric power input data every 15 minutes during the entire period of the performance tests; (b) Determine the average total secondary electric power input by computing the hourly averages using all of the 15-minute readings taken during each performance test.
2. Hydrogen Chloride	a. Wet scrubber operating parameters.	i. Establish site-specific minimum pressure drop, effluent pH, and flow rate operating limits according to § 63.7530(b).	(1) Data from the pressure drop, pH, and liquid flow-rate monitors and the hydrogen chloride performance test.	(a) You must collect pH and liquid flow-rate data every 15 minutes during the entire period of the performance tests; (b) Determine the hourly average pH and liquid flow rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.

TABLE 7 TO SUBPART DDDDD OF PART 63—ESTABLISHING OPERATING LIMITS—Continued

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
	b. Dry scrubber operating parameters.	i. Establish a site-specific minimum sorbent injection rate operating limit according to § 63.7530(b). If different acid gas sorbents are used during the hydrogen chloride performance test, the average value for each sorbent becomes the site-specific operating limit for that sorbent.	(1) Data from the sorbent injection rate monitors and hydrogen chloride or mercury performance test.	(a) You must collect sorbent injection rate data every 15 minutes during the entire period of the performance tests; (b) Determine the hourly average sorbent injection rate by computing the hourly averages using all of the 15-minute readings taken during each performance test. (c) Determine the lowest hourly average of the three test run averages established during the performance test as your operating limit. When your unit operates at lower loads, multiply your sorbent injection rate by the load fraction (e.g., for 50 percent load, multiply the injection rate operating limit by 0.5) to determine the required injection rate.
3. Mercury and dioxins/furans.	a. Activated carbon injection.	i. Establish a site-specific minimum activated carbon injection rate operating limit according to § 63.7530(b).	(1) Data from the activated carbon rate monitors and mercury and dioxins/furans performance tests.	(a) You must collect activated carbon injection rate data every 15 minutes during the entire period of the performance tests; (b) Determine the hourly average activated carbon injection rate by computing the hourly averages using all of the 15-minute readings taken during each performance test. (c) Determine the lowest hourly average established during the performance test as your operating limit. When your unit operates at lower loads, multiply your activated carbon injection rate by the load fraction (e.g., actual heat input divided by heat input during performance test, for 50 percent load, multiply the injection rate operating limit by 0.5) to determine the required injection rate.
4. Carbon monoxide	a. Oxygen	i. Establish a unit-specific limit for minimum oxygen level according to § 63.7520.	(1) Data from the oxygen monitor specified in § 63.7525(a).	(a) You must collect oxygen data every 15 minutes during the entire period of the performance tests;

TABLE 7 TO SUBPART DDDDD OF PART 63—ESTABLISHING OPERATING LIMITS—Continued

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
				(b) Determine the hourly average oxygen concentration by computing the hourly averages using all of the 15-minute readings taken during each performance test. (c) Determine the lowest hourly average established during the performance test as your minimum operating limit.
5. Any pollutant for which compliance is demonstrated by a performance test.	a. Boiler or process heater operating load.	i. Establish a unit specific limit for maximum operating load according to § 63.7520(c).	(1) Data from the operating load monitors or from steam generation monitors.	(a) You must collect operating load or steam generation data every 15 minutes during the entire period of the performance test. (b) Determine the average operating load by computing the hourly averages using all of the 15-minute readings taken during each performance test. (c) Determine the average of the three test run averages during the performance test, and multiply this by 1.1 (110 percent) as your operating limit.

As stated in § 63.7540, you must show continuous compliance with the emission limitations for affected sources according to the following:

TABLE 8 TO SUBPART DDDDD OF PART 63—DEMONSTRATING CONTINUOUS COMPLIANCE

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(c) and § 63.7535; and b. Reducing the opacity monitoring data to 6-minute averages; and c. Maintaining opacity to less than or equal to 10 percent (daily block average).
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 b. Reducing the data to 12-hour block averages; and c. Maintaining the 12-hour average pressure drop and liquid flow-rate at or above the operating limits established during the performance test according to § 63.7530(b).
4. Wet Scrubber pH	a. Collecting the pH monitoring system data according to §§ 63.7525 and 63.7535; and b. Reducing the data to 12-hour block averages; and c. Maintaining the 12-hour average pH at or above the operating limit established during the performance test according to § 63.7530(b).
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 b. Reducing the data to 12-hour block averages; and c. Maintaining the 12-hour average sorbent or carbon injection rate at or above the minimum sorbent or carbon injection rate as defined in § 63.7575.
6. Electrostatic Precipitator Total Secondary Electric Power Input.	a. Collecting the total secondary electric power input monitoring system data for the electrostatic precipitator according to §§ 63.7525 and 63.7535; and b. Reducing the data to 12-hour block averages; and c. Maintaining the 12-hour average total secondary electric power input at or above the operating limits established during the performance test according to § 63.7530(b).
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(b) or (c) as applicable; and b. Keeping monthly records of fuel use according to § 63.7540(a).

TABLE 8 TO SUBPART DDDDD OF PART 63—DEMONSTRATING CONTINUOUS COMPLIANCE—Continued

If you must meet the following operating limits or work practice standards . . .	You must demonstrate continuous compliance by . . .
8. Oxygen content	a. Continuously monitor the oxygen content in the combustion exhaust according to § 63.7525(a). b. Reducing the data to 12-hour block averages; and c. Maintain the 12-hour block average oxygen content in the exhaust at or above the lowest hourly average oxygen level measured during the most recent carbon monoxide performance test.
9. Boiler or process heater operating load	a. Collecting operating load data or steam generation data every 15 minutes. b. Reducing the data to 12-hour block averages; and c. Maintaining the 12-hour average operating load at or below the operating limit established during the performance test according to § 63.7520(c).

As stated in § 63.7550, you must comply with the following requirements for reports:

TABLE 9 TO SUBPART DDDDD OF PART 63—REPORTING REQUIREMENTS

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 (12); and 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 3 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 c. If you have a deviation from any emission limitation (emission limit and operating limit) where you are not using a CMS to comply with that emission limit or operating limit, or a deviation from a work practice standard during the reporting period, the report must contain the information in § 63.7550(d); and 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), or otherwise not operating, the report must contain the information in § 63.7550(e).	Semiannually, annually, or biennially according to the requirements in § 63.7550(b).

As stated in § 63.7565, you must comply with the applicable General Provisions according to the following:

TABLE 10 TO SUBPART DDDDD OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART DDDDD

Citation	Subject	Applies to subpart DDDDD
§ 63.1	Applicability	Yes.
§ 63.2	Definitions	Yes. Additional terms defined in § 63.7575
§ 63.3	Units and Abbreviations	Yes.
§ 63.4	Prohibited Activities and Circumvention	Yes.
§ 63.5	Preconstruction Review and Notification Requirements	Yes.
§ 63.6(a), (b)(1)–(b)(5), (b)(7), (c)	Compliance with Standards and Maintenance Requirements	Yes.
§ 63.6(e)(1)(i)	General duty to minimize emissions.	No. See § 63.7500(a)(3) for the general duty requirement.
§ 63.6(e)(1)(ii)	Requirement to correct malfunctions as soon as practicable.	No.
§ 63.6(e)(3)	Startup, shutdown, and malfunction plan requirements.	No.
§ 63.6(f)(1)	Startup, shutdown, and malfunction exemptions for compliance with non-opacity emission standards..	No.
§ 63.6(f)(2) and (3)	Compliance with non-opacity emission standards.	Yes.
§ 63.6(g)	Use of alternative standards	Yes.
§ 63.6(h)(1)	Startup, shutdown, and malfunction exemptions to opacity standards.	No. See § 63.7500(a).
§ 63.6(h)(2) to (h)(9)	Determining compliance with opacity emission standards	Yes.

TABLE 10 TO SUBPART DDDDD OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART DDDDD—Continued

Citation	Subject	Applies to subpart DDDDD
§ 63.6(i)	Extension of compliance.	Yes.
§ 63.6(j)	Presidential exemption.	Yes.
§ 63.7(a), (b), (c), and (d)	Performance Testing Requirements	Yes.
§ 63.7(e)(1)	Conditions for conducting performance tests.	No. Subpart DDDDD specifies conditions for conducting performance tests at § 63.7520(a).
§ 63.7(e)(2)–(e)(9), (f), (g), and (h)	Performance Testing Requirements	Yes.
§ 63.8(a) and (b)	Applicability and Conduct of Monitoring	Yes.
§ 63.8(c)(1)	Operation and maintenance of CMS	Yes.
§ 63.8(c)(1)(i)	General duty to minimize emissions and CMS operation	No. See § 63.7500(a)(3).
§ 63.8(c)(1)(ii)	Operation and maintenance of CMS	Yes.
§ 63.8(c)(1)(iii)	Startup, shutdown, and malfunction plans for CMS	No.
§ 63.8(c)(2) to (c)(9)	Operation and maintenance of CMS	Yes.
§ 63.8(d)(1) and (2)	Monitoring Requirements, Quality Control Program	Yes.
§ 63.8(d)(3)	Written procedures for CMS	Yes, except for the last sentence, which refers to a startup, shutdown, and malfunction plan. Startup, shutdown, and malfunction plans are not required.
§ 63.8(e)	Performance evaluation of a CMS	Yes.
§ 63.8(f)	Use of an alternative monitoring method.	Yes.
63.8(g)	Reduction of monitoring data.	Yes.
§ 63.9	Notification Requirements	Yes.
§ 63.10(a), (b)(1)	Recordkeeping and Reporting Requirements	Yes.
§ 63.10(b)(2)(i)	Recordkeeping of occurrence and duration of startups or shutdowns	Yes.
§ 63.10(b)(2)(ii)	Recordkeeping of malfunctions	No. See § 63.7555(d)(7) for recordkeeping of occurrence and duration and § 63.7555(d)(8) for actions taken during malfunctions.
§ 63.10(b)(2)(iii)	Maintenance records	Yes.
§ 63.10(b)(2)(iv) and (v)	Actions taken to minimize emissions during startup, shutdown, or malfunction.	No.
§ 63.10(b)(2)(vi)	Recordkeeping for CMS malfunctions	Yes.
§ 63.10(b)(2)(vii) to (xiv)	Other CMS requirements	Yes.
§ 63.10(b)(3)	Recordkeeping requirements for applicability determinations	No.
§ 63.10(c)(1) to (9)	Recordkeeping for sources with CMS	Yes.
§ 63.10(c)(10) and (11)	Recording nature and cause of malfunctions, and corrective actions	No. See § 63.7555(d)(7) for recordkeeping of occurrence and duration and § 63.7555(d)(8) for actions taken during malfunctions.
§ 63.10(c)(12) and (13)	Recordkeeping for sources with CMS	Yes.
§ 63.10(c)(15)	Use of startup, shutdown, and malfunction plan	No.
§ 63.10(d)(1) and (2)	General reporting requirements	Yes.
§ 63.10(d)(3)	Reporting opacity or visible emission observation results	No.
§ 63.10(d)(4)	Progress reports under an extension of compliance	Yes.
§ 63.10(d)(5)	Startup, shutdown, and malfunction reports	No. See § 63.7550(c)(11) for malfunction reporting requirements.
§ 63.10(e) and (f)		Yes.
§ 63.11	Control Device Requirements	No.
§ 63.12	State Authority and Delegation	Yes.
§ 63.13–63.16	Addresses, Incorporation by Reference, Availability of Information, Performance Track Provisions.	Yes.
§ 63.1(a)(5),(a)(7)–(a)(9), (b)(2), (c)(3)-(4), (d), 63.6(b)(6), (c)(3), (c)(4), (d), (e)(2), (e)(3)(ii), (h)(3), (h)(5)(iv), 63.8(a)(3), 63.9(b)(3), (h)(4), 63.10(c)(2)–(4), (c)(9)..	Reserved	No.

TABLE 11 TO SUBPART DDDDD OF PART 63—TOXIC EQUIVALENCY FACTORS FOR DIOXINS/FURANS

Dioxin/furan congener	Toxic equivalency factor
2,3,7,8-tetrachlorinated dibenzo-p-dioxin	1
1,2,3,7,8-pentachlorinated dibenzo-p-dioxin	1
1,2,3,4,7,8-hexachlorinated dibenzo-p-dioxin	0.1
1,2,3,7,8,9-hexachlorinated dibenzo-p-dioxin	0.1
1,2,3,6,7,8-hexachlorinated dibenzo-p-dioxin	0.1

Table 11 to Subpart DDDDD of Part 63—Toxic Equivalency Factors for Dioxins/Furans—Continued

Dioxin/furan congener	Toxic equivalency factor
1,2,3,4,6,7,8-heptachlorinated dibenzo-p-dioxin	0.01
octachlorinated dibenzo-p-dioxin	0.0003
2,3,7,8-tetrachlorinated dibenzofuran	0.1
2,3,4,7,8-pentachlorinated dibenzofuran	0.3
1,2,3,7,8-pentachlorinated dibenzofuran	0.03
1,2,3,4,7,8-hexachlorinated dibenzofuran	0.1
1,2,3,6,7,8-hexachlorinated dibenzofuran	0.1
1,2,3,7,8,9-hexachlorinated dibenzofuran	0.1
2,3,4,6,7,8-hexachlorinated dibenzofuran	0.1
1,2,3,4,6,7,8-heptachlorinated dibenzofuran	0.01
1,2,3,4,7,8,9-heptachlorinated dibenzofuran	0.01
octachlorinated dibenzofuran	0.0003

Table 12 to Subpart DDDDD of Part 63—Alternative Emission Limits for New or Reconstructed Boilers and Process Heaters That Commenced Construction or Reconstruction After June 4, 2010, and Before May 20, 2011

If your boiler or process heater is in this subcategory	For the following pollutants	The emissions must not exceed the following emission limits, except during periods of startup and shutdown	Using this specified sampling volume or test run duration
1. Units in all subcategories designed to burn solid fuel	a. Mercury	3.5E–06 lb per MMBtu of heat input.	For M29, collect a minimum of 2 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [a] collect a minimum of 2 dscm.
2. Units in all subcategories designed to burn solid fuel that combust at least 10 percent biomass/bio-based solids on an annual heat input basis and less than 10 percent coal/solid fossil fuels on an annual heat input basis.	a. Particulate Matter	0.008 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr).	Collect a minimum of 1 dscm per run.
	b. Hydrogen Chloride	0.004 lb per MMBtu of heat input.	For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.
3. Units in all subcategories designed to burn solid fuel that combust at least 10 percent coal/solid fossil fuels on an annual heat input basis and less than 10 percent biomass/bio-based solids on an annual heat input basis.	a. Particulate Matter	0.0011 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr).	Collect a minimum of 3 dscm per run.
	b. Hydrogen Chloride	0.0022 lb per MMBtu of heat input.	For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.
4. Units designed to burn pulverized coal/solid fossil fuel.	a. CO	90 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Dioxins/Furans	0.003 ng/dscm (TEQ) corrected to 7 percent oxygen.	Collect a minimum of 4 dscm per run.
5. Stokers designed to burn coal/solid fossil fuel	a. CO	7 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Dioxins/Furans	0.003 ng/dscm (TEQ) corrected to 7 percent oxygen.	Collect a minimum of 4 dscm per run.
6. Fluidized bed units designed to burn coal/solid fossil fuel.	a. CO	30 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.

TABLE 12 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER JUNE 4, 2010, AND BEFORE MAY 20, 2011—Continued

If your boiler or process heater is in this subcategory	For the following pollutants	The emissions must not exceed the following emission limits, except during periods of startup and shutdown	Using this specified sampling volume or test run duration
	b. Dioxins/Furans	0.002 ng/dscm (TEQ) corrected to 7 percent oxygen.	Collect a minimum of 4 dscm per run.
7. Stokers designed to burn biomass/bio-based solids	a. CO	560 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Dioxins/Furans	0.005 ng/dscm (TEQ) corrected to 7 percent oxygen.	Collect a minimum of 4 dscm per run.
8. Fluidized bed units designed to burn biomass/bio-based solids.	a. CO	260 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Dioxins/Furans	0.02 ng/dscm (TEQ) corrected to 7 percent oxygen.	Collect a minimum of 4 dscm per run.
9. Suspension burners/Dutch Ovens designed to burn biomass/bio-based solids.	a. CO	1,010 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Dioxins/Furans	0.2 ng/dscm (TEQ) corrected to 7 percent oxygen.	Collect a minimum of 4 dscm per run.
10. Fuel cells designed to burn biomass/bio-based solids.	a. CO	470 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Dioxins/Furans	0.003 ng/dscm (TEQ) corrected to 7 percent oxygen.	Collect a minimum of 4 dscm per run.
11. Hybrid suspension/grate units designed to burn biomass/bio-based solids.	a. CO	1,500 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Dioxins/Furans	0.2 ng/dscm (TEQ) corrected to 7 percent oxygen.	Collect a minimum of 4 dscm per run.
12. Units designed to burn liquid fuel	a. Particulate Matter	0.002 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr).	Collect a minimum of 2 dscm per run.
	b. Hydrogen Chloride	0.0032 lb per MMBtu of heat input.	For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.
	c. Mercury	3.0E–07 lb per MMBtu of heat input.	For M29, collect a minimum of 2 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[a] collect a minimum of 2 dscm.
	d. CO	3 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	e. Dioxins/Furans	0.002 ng/dscm (TEQ) corrected to 7 percent oxygen.	Collect a minimum of 4 dscm per run.
13. Units designed to burn liquid fuel located in non-continental States and territories.	a. Particulate Matter	0.002 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr).	Collect a minimum of 2 dscm per run.

TABLE 12 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER JUNE 4, 2010, AND BEFORE MAY 20, 2011—Continued

If your boiler or process heater is in this subcategory	For the following pollutants	The emissions must not exceed the following emission limits, except during periods of startup and shutdown	Using this specified sampling volume or test run duration
	b. Hydrogen Chloride	0.0032 lb per MMBtu of heat input.	For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.
	c. Mercury	7.8E–07 lb per MMBtu of heat input.	For M29, collect a minimum of 1 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [a] collect a minimum of 2 dscm.
	d. CO	51 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	e. Dioxins/Furans	0.002 ng/dscm (TEQ) corrected to 7 percent oxygen.	Collect a minimum of 4 dscm per run.
14. Units designed to burn gas 2 (other) gases	a. Particulate Matter	0.0067 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr).	Collect a minimum of 1 dscm per run.
	b. Hydrogen Chloride	0.0017 lb per MMBtu of heat input.	For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.
	c. Mercury	7.9E–06 lb per MMBtu of heat input.	For M29, collect a minimum of 1 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [a] collect a minimum of 2 dscm.
	d. CO	3 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	e. Dioxins/Furans	0.08 ng/dscm (TEQ) corrected to 7 percent oxygen.	Collect a minimum of 4 dscm per run.

[a] Incorporated by reference, see § 63.14.

[FR Doc. 2011–4494 Filed 3–18–11; 8:45 am]

BILLING CODE 6560–50–P

(ii) * * *

(*a*) Multiplying the mass amount of emissions (tpy), for each of the six greenhouse gases in the pollutant GHGs, by the gas's associated global warming potential published at Table A–1 to subpart A of part 98 of this chapter—Global Warming Potentials. For purposes of this paragraph (b)(48)(ii)(*a*), prior to [DATE 3 YEARS AFTER THE EFFECTIVE DATE OF THE FINAL DEFERRAL RULE], the mass of the greenhouse gas carbon dioxide shall not include carbon dioxide emissions resulting from the combustion or decomposition of non-fossilized and biodegradable organic material originating from plants, animals, or micro-organisms (including products, by-products, residues and waste from agriculture, forestry and related industries as well as the non-fossilized and biodegradable organic fractions of industrial and municipal wastes, including gases and liquids recovered from the decomposition of non-fossilized and biodegradable organic material).

* * * * *

PART 52—[AMENDED]

3. The authority citation for part 52 continues to read as follows:

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

Subpart A—[Amended]

4. Section 52.21 is amended by revising paragraph (b)(49)(ii)(*a*) to read as follows:

§ 52.21 Prevention of significant deterioration of air quality.

* * * * *

(b) * * *

(49) * * *

(ii) * * *

(*a*) Multiplying the mass amount of emissions (tpy), for each of the six greenhouse gases in the pollutant GHGs, by the gas's associated global warming potential published at Table A–1 to subpart A of part 98 of this chapter—Global Warming Potentials. For purposes of this paragraph, prior to [DATE 3 YEARS AFTER THE EFFECTIVE DATE OF THE FINAL DEFERRAL RULE], the mass of the greenhouse gas carbon dioxide shall not include carbon dioxide emissions resulting from the combustion or decomposition of non-fossilized and biodegradable organic material originating from plants, animals, or micro-organisms (including products, by-products, residues and waste from agriculture, forestry and related industries as well as the non-fossilized and biodegradable organic fractions of industrial and municipal wastes, including gases and liquids recovered from the decomposition of non-fossilized and biodegradable organic material).

* * * * *

PART 70—[AMENDED]

5. The authority citation for part 70 continues to read as follows:

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

6. Section 70.2 is amended by revising paragraph (2) of the definition of "Subject to regulation" to read as follows:

§ 70.2 Definitions.

* * * * *

Subject to regulation * * *

(2) The term tpy CO_2 equivalent emissions (CO_2e) shall represent an amount of GHGs emitted, and shall be computed by multiplying the mass amount of emissions (tpy), for each of the six greenhouse gases in the pollutant GHGs, by the gas's associated global warming potential published at Table A–1 to subpart A of part 98 of this chapter—Global Warming Potentials, and summing the resultant value for each to compute a tpy CO_2e. For purposes of this paragraph, prior to [DATE 3 YEARS AFTER THE EFFECTIVE DATE OF THE FINAL DEFERRAL RULE], the mass of the greenhouse gas carbon dioxide shall not include carbon dioxide emissions resulting from the combustion or decomposition of non-fossilized and biodegradable organic material originating from plants, animals, or micro-organisms (including products, by-products, residues and waste from agriculture, forestry and related industries as well as the non-fossilized and biodegradable organic fractions of industrial and municipal wastes, including gases and liquids recovered from the decomposition of non-fossilized and biodegradable organic material).

* * * * *

PART 71—[AMENDED]

7. The authority citation for part 51 continues to read as follows:

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

Subpart A—[Amended]

8. Section 71.2 is amended by revising paragraph (2) of the definition of "Subject to regulation" to read as follows:

§ 71.2 Definitions.

* * * * *

Subject to regulation * * *

(2) The term tpy CO_2 equivalent emissions (CO_2e) shall represent an amount of GHGs emitted, and shall be computed by multiplying the mass amount of emissions (tpy), for each of the six greenhouse gases in the pollutant GHGs, by the gas's associated global warming potential published at Table A–1 to subpart A of part 98 of this chapter—Global Warming Potentials, and summing the resultant value for each to compute a tpy CO_2e. For purposes of this paragraph, prior to [DATE 3 YEARS AFTER THE EFFECTIVE DATE OF THE FINAL DEFERRAL RULE], the mass of the greenhouse gas carbon dioxide shall not include carbon dioxide emissions resulting from the combustion or decomposition of non-fossilized and biodegradable organic material originating from plants, animals, or micro-organisms (including products, by-products, residues and waste from agriculture, forestry and related industries as well as the non-fossilized and biodegradable organic fractions of industrial and municipal wastes, including gases and liquids recovered from the decomposition of non-fossilized and biodegradable organic material).

* * * * *

[FR Doc. 2011–6438 Filed 3–18–11; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 60 and 63

[EPA–HQ–OAR–2002–0058; EPA–HQ–OAR–2006–0790; EPA–HQ–OAR–2003–0119; FRL–9272–7]

RIN 2060–AQ25; RIN 2060–AM44; RIN 2060–AO12

National Emission Standards for Hazardous Air Pollutants; Notice of Reconsideration

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice of reconsideration of final rules.

SUMMARY: EPA is initiating a reconsideration process with respect to certain aspects of the national emission standards for hazardous air pollutants (NESHAP) for new and existing sources for Major Source Industrial, Commercial, and Institutional Boilers and Process Heaters; the NESHAP for new and existing sources for Area Source Industrial, Commercial, and Institutional Boilers; and standards of performance for new Commercial and

Industrial Solid Waste Incineration Units and emission guidelines for existing Commercial and Industrial Solid Waste Incineration Units published as final rules elsewhere in this issue of this **Federal Register**.

FOR FURTHER INFORMATION CONTACT: National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters: Mr. Brian Shrager, Energy Strategies Group, Sector Policies and Programs Division, (D243–01), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; Telephone number: (919) 541–7689; Fax number (919) 541–5450; E-mail address: *shrager.brian@epa.gov.*

National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers: Mr. Jim Eddinger, Energy Strategies Group, Sector Policies and Programs Division, (D243–01), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–5426; Fax number (919) 541–5450; e-mail address: *eddinger.jim@epa.gov.*

Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Commercial and Industrial Solid Waste Incineration (CISWI) Units: Ms. Toni Jones, Natural Resource and Commerce Group, Sector Policies and Programs Division (E143–03), Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–0316; fax number: (919) 541–3470; e-mail address: *jones.toni@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. General Information

A. Reconsideration of the Emissions Standards for Major Boilers and Process Heaters, Area Source Boilers, and Commercial and Industrial Solid Waste Incinerators

In separate final rules documents published elsewhere in today's **Federal Register**, EPA is issuing emissions standards for new and existing sources in the following source categories: Major source boilers and process heaters, area source boilers, and commercial and industrial solid waste incinerators. In this notice, we are convening a proceeding for reconsideration of certain portions of these emissions standards. The Agency is in the process of developing a proposed reconsideration notice that identifies the specific elements of the rules for which we believe further public comment is appropriate and any provisions that we propose to modify after more fully evaluating the data and comments already received. At that time, we may also seek public comment on other aspects of the portions of the rules we decide to reconsider in addition to other provisions in these rules. We will also evaluate any petitions submitted to the Agency by members of the public requesting that the Agency reconsider any aspects of these rules. We intend to consider for inclusion in any forthcoming proposed reconsideration notice all additional issues for which we determine that reconsideration is appropriate.

We recognize that certain issues of central relevance to these rules arose after the period for public comment or may have been impracticable to comment upon. Therefore, we believe that reconsideration is appropriate under section 307(d)(7)(B) of the Clean Air Act. While we have taken final action on the rules identified above, and believe that the final rules reflect reasonable approaches consistent with the requirements of the Clean Air Act, some of the issues identified in the comments raise difficult technical issues that we believe may benefit from additional public involvement.

Therefore, we are initiating reconsideration of a number of issues in the major and area sources boilers rules, and the commercial and industrial solid waste incineration rule. The following issues concern provisions in the final rules that are appropriate and consistent with the requirements of the Act, but for which we believe reconsideration and additional opportunity for public review and comment should be obtained:

- Revisions to the proposed subcategories in the major source boilers rule.
- Establishment of a fuel specification in the major source boilers rule through which gas-fired boilers that use a fuel other than natural gas may be considered Gas 1 units.
- Establishing work practice standards for limited use major source boilers.
- Establishment of standards for biomass and oil-fired area source boilers based on generally available control technology.
- Revision of the proposed subcategory for energy recovery units for CISWI units.
- Establishment of limitations on fuel switching provisions for CISWI units.
- Revision to the proposed definition of CISWI to exclude cyclonic burn barrels.
- Providing an affirmative defense for malfunction events for major and area source boilers and for CISWI units.

The following additional issues concern actions taken in the final rules for which we believe reconsideration under section 307(d) and, potentially, further revisions may be warranted because they involve issues of central relevance that arose after the period for public comment or may have been impracticable to comment upon:

- Revisions to the proposed monitoring requirements for carbon monoxide for major source boilers and for CISWI units.
- Revisions to the proposed dioxin emission limit and testing requirement for major source boilers.
- Establishing a full-load stack test requirement for carbon monoxide coupled with continuous oxygen monitoring for major source boilers and CISWI units.
- Establishing a definition of "homogenous waste" in the CISWI rule.
- Setting PM standards under generally available control technology for oil-fired area source boilers.
- Certain findings regarding the applicability of Title V permitting requirements for area source boilers.

Additional information concerning issues and concerns presented by commenters can be found in the dockets accompanying each of the rules under reconsideration in today's notice.

List of Subjects

40 CFR Part 60

Environmental protection, Air pollution control, Hazardous substances, Reporting and recordkeeping requirements.

40 CFR Part 63

Environmental protection, Air pollution control, Hazardous substances, Reporting and recordkeeping requirements.

Dated: February 21, 2011.

Lisa P. Jackson,

Administrator.

[FR Doc. 2011–4490 Filed 3–18–11; 8:45 am]

BILLING CODE 6560–50–P

a chance to comment on EPA's determination after the effective date, and EPA will consider any comments received in determining whether to reverse such action.

EPA believes that notice-and-comment rulemaking before the effective date of this action is impracticable and contrary to the public interest. EPA has reviewed the State's submittal and, through its proposed action, is indicating that it is more likely than not that the State is no longer obligated to submit the plan that was the basis for the finding that started the sanctions clocks. Therefore, it is not in the public interest to impose sanctions. Moreover, it would be impracticable to go through notice-and-comment rulemaking on a finding that the State no longer is required to submit the plan prior to the rulemaking approving the State's termination determination. Therefore, EPA believes that it is necessary to use the interim final rulemaking process to defer sanctions while EPA completes its rulemaking process on the approvability of the State's submittal. Moreover, with respect to the effective date of this action, EPA is invoking the good cause exception to the 30-day notice requirement of the APA because the purpose of this notice is to relieve a restriction (5 U.S.C. 553(d)(1)).

Note that today's action has no impact on the January 5, 2010 (75 FR 232) findings regarding the Southeast Desert and the Los Angeles-South Coast Air Basin.

III. Statutory and Executive Order Reviews

This action defers Federal sanctions and imposes no additional requirements.

Under Executive Order 12866 (58 FR 51735, October 4, 1993), this action is not a "significant regulatory action" and therefore is not subject to review by the Office of Management and Budget.

This action is not subject to Executive Order 13211, "Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use" (66 FR 28355, May 22, 2001) because it is not a significant regulatory action.

The administrator certifies that this action will not have a significant economic impact on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*).

This rule does not contain any unfunded mandate or significantly or uniquely affect small governments, as described in the Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4).

This rule does not have Tribal implications because it will not have a substantial direct effect on one or more Indian Tribes, on the relationship between the Federal government and Indian Tribes, or on the distribution of power and responsibilities between the Federal government and Indian Tribes, as specified by Executive Order 13175 (65 FR 67249, November 9, 2000).

This action does not have Federalism implications because it does 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 (64 FR 43255, August 10, 1999).

This rule is not subject to Executive Order 13045, "Protection of Children from Environmental Health Risks and Safety Risks" (62 FR 19885, April 23, 1997), because it is not economically significant.

The requirements of section 12(d) of the National Technology Transfer and Advancement Act of 1995 (15 U.S.C. 272) do not apply to this rule because it imposes no standards.

This rule does not impose an information collection burden under the provisions of the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*).

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 to Congress and the Comptroller General. However, section 808 provides that any rule for which the issuing agency for good cause finds that notice and public procedure thereon are impracticable, unnecessary, or contrary to the public interest, shall take effect at such time as the agency promulgating the rule determines. 5 U.S.C. 808(2). EPA has made such a good cause finding, including the reasons therefore, and established an effective date of May 18, 2011. EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This rule is not a "major rule" as defined by 5 U.S.C. 804(2).

Under section 307(b)(1) of the CAA, petitions for judicial review of this action must be filed in the United States Court of Appeals for the appropriate circuit by July 18, 2011. Filing a petition for reconsideration by the Administrator of this final rule does not affect the finality of this rule for the purpose of judicial review nor does it extend the time within which petition for judicial review may be filed, and shall not postpone the effectiveness of such rule or action. This action may not be challenged later in proceedings to enforce its requirements (see section 307(b)(2)).

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Incorporation by reference, Intergovernmental regulations, Ozone, Reporting and recordkeeping requirements.

Dated: May 9, 2011.

Jared Blumenfeld,

Regional Administrator, Region IX.

[FR Doc. 2011–12062 Filed 5–17–11; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 60 and 63

[EPA–HQ–OAR–2002–0058; EPA–HQ–2003–0119; FRL–9308–6]

RIN 2060–AQ25; 2060–AO12

Industrial, Commercial, and Institutional Boilers and Process Heaters and Commercial and Industrial Solid Waste Incineration Units

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rules; Delay of effective dates.

SUMMARY: The EPA is delaying the effective dates for the final rules titled "National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters" and "Standards of Performance for New Sources and Emission Guidelines for Existing Sources: Commercial and Industrial Solid Waste Incineration Units" under the authority of the Administrative Procedure Act (APA) until the proceedings for judicial review of these rules are completed or the EPA completes its reconsideration of the rules, whichever is earlier.

DATES: The effective dates of the final rules published in the **Federal Register** on March 21, 2011 (76 FR 15608 and 76 FR 15704), are delayed until such time as judicial review is no longer pending or until the EPA completes its reconsideration of the rules, whichever is earlier. The Director of the **Federal Register** has reviewed certain publications listed in these final rules for incorporation by reference approval. That approval is delayed until such time as the proceedings for judicial review of these rules are completed or the EPA completes its reconsideration of the rules, whichever is earlier. The EPA will publish in the **Federal Register** announcing the effective dates and the incorporation by reference approvals once delay is no longer necessary.

ADDRESSES: *Docket:* The final rules, the petitions for reconsideration, and all other documents in the record for the rulemakings are in Docket ID. No. EPA–HQ–OAR–2002–0058 and EPA–HQ–OAR–2003–0119. All documents in the dockets are listed in the *http://www.regulations.gov* index. Although listed in the index, some information is not publicly available, *e.g.,* Confidential Business Information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available either electronically in *http://www.regulations.gov* or in hard copy at the EPA's Docket Center, Public Reading Room, EPA West Building, Room 3334, 1301 Constitution Avenue, NW., Washington, DC 20004. This Docket Facility is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1741.

FOR FURTHER INFORMATION CONTACT: "National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters": Mr. Brian Shrager, Energy Strategies Group, Sector Policies and Programs Division, Office of Air Quality Planning and Standards (D243–01), U.S. Environmental Protection Agency, Research Triangle Park, NC 27711, telephone (919) 541–7689, fax number (919) 541–5450, e-mail address: *shrager.brian@epa.gov.* "Standards of Performance for New Sources and Emission Guidelines for Existing Sources: Commercial and Industrial Solid Waste Incineration Units": Ms. Toni Jones, Fuels and Incineration Group, Sector Policies and Programs Division, Office of Air Quality Planning and Standards (E143–03), U.S. Environmental Protection Agency, Research Triangle Park, NC 27711, telephone (919) 541–0316, fax number (919) 541–3470, e-mail address: *jones.toni@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. Background

On March 21, 2011, the EPA issued a final rule to regulate emissions of hazardous air pollutants (HAP) from industrial, commercial, and institutional boilers and process heaters located at major sources of HAP emissions (the "Major Source Boiler MACT"). On the same date, the EPA issued a final rule to regulate emissions of certain air pollutants from commercial and industrial solid waste incineration units (the "CISWI Rule"). For further information on the Major Source Boiler MACT, *see* 76 FR 15608 (March 21, 2011). For further information on the CISWI Rule, *see* 76 FR 15704 (March 21, 2011). In the March 21 notices, the EPA established an effective date of May 20, 2011, for each rule.

On the same day the rules were issued, the EPA also published a notice explaining that the Agency was in the process of developing a notice proposing reconsideration of certain aspects of both rules. 76 FR 15267. In that notice, the EPA explained that the proposed reconsideration would address issues on which the EPA believes further opportunity for public comment is appropriate, as well as any provisions of the rules that the EPA believes warrant modification after further consideration of the data and comments already received. The EPA has received petitions from a number of interested parties seeking reconsideration of both rules. The petitions identify specific issues that the EPA is being asked to reconsider. The EPA intends to initiate a reconsideration process for both rules, as explained above. The EPA will issue a notice of proposed reconsideration of each rule that identifies the specific issue or issues raised in the petitions on which the Agency is granting reconsideration. The EPA understands that members of the public may wish to submit additional data and information to inform the EPA's proposed reconsideration, and the Agency will consider any additional information submitted in time to do so. Given the anticipated schedule for the reconsideration process, we request that any additional data and information be provided to the EPA by July 15, 2011, to allow the Agency to fully consider it.

The EPA has also received petitions for judicial review of the Major Source Boiler MACT from the United States Sugar Corporation as well as from a coalition of industry groups. The EPA has received a petition for judicial review of the CISWI Rule from a coalition of industry groups as well. Under section 705 of the APA, "an agency * * * may postpone the effective date of [an] action taken by it pending judicial review." The provision requires that the Agency find that justice requires postponing the action, that the action has not gone into effect, and that litigation is pending. As described above, neither the Major Source Boiler MACT nor the CISWI Rule has gone into effect and petitions for judicial review of both rules have been filed.

We find that justice requires postponing the effectiveness of these rules. As explained in the March 21, 2011, notice, EPA has identified several issues in the final rules which it intends to reconsider because we believe the public did not have a sufficient opportunity to comment on certain revisions EPA made to the proposed rules. These issues include revisions to the proposed subcategories and revisions to some of the proposed emissions limits. In addition, EPA received data before finalizing both rules but was unable to incorporate that data into the final rules given the court deadline for issuing the rules, which the Agency was unable to extend. EPA also notes thousands of facilities across multiple, diverse industries will need to begin to make major compliance investments soon, in light of the pressing compliance deadlines. These investments may not be reversible if the standards are in fact revised following reconsideration and full evaluation of all relevant data.

Finally, the EPA notes that it is delaying the effective date of the Major Source Boiler MACT and the CISWI Rule pursuant to the APA, rather than section 307(d)(7)(B) of the Clean Air Act. As explained above, the APA authorizes the EPA to find that justice requires postponing the effective date of a rule when litigation is pending. In contrast, the Clean Air Act authorizes the EPA to stay the effectiveness of a rule for three months if the Administrator has convened a proceeding to reconsider the rule. The EPA further notes that section 307(d) of the Act expressly states that it is intended to replace only sections 553–557 of the APA (except as otherwise provided in section 307(d)), and does not state that it replaces section 705 of the APA. Therefore, the EPA has the discretion to decide whether it is appropriate to delay the effective date of a rule under either provision, based on the specific facts and circumstances before the Agency. Since petitions for judicial review of both the Major Source Boiler MACT and the CISWI Rule have been filed, and, as explained above, justice requires a delay of the effective dates, it is reasonable for the EPA to exercise its authority to delay the effective dates of the Major Source Boiler MACT and the CISWI Rule under the APA for a period that exceeds three months.

II. Issuance of a Stay and Delay of Effective Date

Pursuant to section 705 of the APA, the EPA hereby postpones the effectiveness of the Major Source Boiler MACT and the CISWI Rule until the proceedings for judicial review of these rules are complete or the EPA completes its reconsideration of the rules, whichever is earlier. By this action, we are delaying the effective date of both rules, published in the **Federal Register** on March 21, 2011 (76 FR 15608 and 76 FR 15704). The delay of the effective date of the CISWI Rule applies only to those provisions issued on March 21, 2011, and not to any provisions of 40 CFR part 60, subparts CCCC and DDDD, in place prior to that date. This delay of effectiveness will remain in place until the proceedings for judicial review are completed or the EPA completes its reconsideration of the rules, whichever is earlier, and the Agency publishes a notice in the **Federal Register** announcing that the rules are in effect.

List of Subjects

40 CFR Part 60

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

40 CFR Part 63

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

For the reasons set forth above, under the authority at 7 U.S.C. 705, the effective dates of FRL 9272–8, 76 FR 15608 (March 21, 2011), and FRL 9273–4, 76 FR 15704 (March 21, 2011) are delayed until further notice.

Dated: May 16, 2011.

Lisa P. Jackson,

Administrator.

[FR Doc. 2011–12308 Filed 5–17–11; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[OAR–2004–0080, FRL–9306–8]

RIN 2060–AF00

Method 301—Field Validation of Pollutant Measurement Methods From Various Waste Media

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action amends EPA's Method 301, Field Validation of Pollutant Measurement Methods from Various Waste Media. We revised the procedures in Method 301 based on our experience in applying the method and to correct errors that were brought to our attention. The revised Method 301 is more flexible, less expensive, and easier to use. This action finalizes amendments to Method 301 after considering comments received on the proposed rule published in the **Federal Register** on December 22, 2004.

DATES: This final rule is effective on May 18, 2011.

ADDRESSES: EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2004–0080. All documents in the docket are listed in the *http://www.regulations.gov* index. Although listed in the index, some information is not publicly available, *e.g.*, confidential business information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically at *http://www.regulations.gov* or in hard copy at the Air Docket, EPA/DC, EPA West, Room 3334, 1301 Constitution Avenue, NW., Washington, DC. The Docket Facility and the Public Reading Room are open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Ms. Lula H. Melton, Office of Air Quality Planning and Standards, Air Quality Assessment Division, Measurement Technology Group (E143–02), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–2910; fax number: (919) 541–0516; e-mail address: *melton.lula@epa.gov.*

SUPPLEMENTARY INFORMATION:

Table of Contents

I. General Information

A. Does this action apply to me?

Method 301 affects/applies to you if you want to propose a new or alternative test method to meet an EPA compliance requirement.

B. Where can I obtain a copy of this action?

In addition to being available in the docket, an electronic copy of this rule will also be available on the Worldwide Web (www) through the Technology Transfer Network (TTN). Following the Administrator's signature, a copy of the final rule will be placed on the TTN's policy and guidance page for newly proposed or promulgated rules at *http://www.epa.gov/ttn/oarpg.* The TTN provides information and technology exchange in various areas of air pollution control. A redline strikeout

http://cfpub.epa.gov/rblc/index.cfm?action=Results.PermitSearchResults
Last updated on Friday, July 15, 2011

Technology Transfer Network
Clean Air Technology Center - RACT/BACT/LAER Clearinghouse

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Please note that the use of your browser's BACK button to change the search conditions may result in inaccurate results.

Matching Facilities for Search Criteria : Tips
Permit Date Between 1/1/1990 And 07/15/2011
And Process Type = 90.008

These results are for USA only.

Check Un-Check **ALL Facilities** New Search

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLC ID	CORPORATE/COMPANY & FACILITY NAME	PROCESS CODE	PROCESS DESCRIPTION	PERMIT NUMBER & PERMIT DATE
Sort By	Sort By			Sort By
☑ GA-0135	CARBO CERAMIC, INC. CARBO CERAMIC, INC. - MYINTYRE	90.008	ALUMINA-RICH CLAY, WATER AND BAUXITE	3295-319-0027-V-03-2 12/16/2009
☑ OK-0110	DALITALIA LLC MUSKOGEE PORCELAIN FLOOR TILE PLT	90.008	MATERIALS HANDLING	2004-198-TV 10/21/2005
		90.008	KILNS	
		90.008	GLAZE/BODY PREP	
☑ GA-0074	DRY BRANCH KAOLIN CO. DRY BRANCH KAOLIN CO.	90.008	SILOS (5)	3295-143-11081 11/06/1995
		90.008	CALCINER COOLER	
		90.008	PULVERIZERS (8)	
		90.008	CALCINER NO. 4	
		90.008	BIN VENTS (3)	
		90.008	TRUCK LOADING	
		90.008	RAILCAR LOADING	

Check Un-Check **ALL Facilities** Back to Top of Page

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Formatting your report may take a while, especially if your facility has a large number of processes and pollutants. The detail reports take the longest amount of time because they include the most information. Please be patient after you select "Create report"

Help

○ Process Index Report ● TXT ○ pdf
○ Process Type Summary(with Agency Contact Info) ● TXT ○ pdf
○ Comprehensive Report ● TXT ○ pdf
○ Free Form Report(Customizable Fields Selection)
○ Free Form Report ● TXT ○ pdf
○ Export/Import Report(ASCII Delineated Text)

Create report

http://cfpub.epa.gov/rblc/index.cfm?action=PermitDetail.ProcessInfo&facility_id=27066&PROCESS_ID=107422
Last updated on Friday, July 15, 2011

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Process Information - Details

For information about the pollutants related to this process, click on the specific pollutant in the list below.

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FINAL

RBLC ID: GA-0135
Corporate/Company: CARBO CERAMIC, INC.
Facility Name: CARBO CERAMIC, INC. - MYINTYRE
Process: ALUMINA-RICH CLAY, WATER AND BAUXITE

Primary Fuel:
Throughput: 0
Process Code: 90.008

Pollutant Information - List of Pollutants

Help

Pollutant	Primary Emission Limit	Basis	Verified
Carbon Monoxide	20.0000 LB/H	BACT-PSD	YES
Hydrochloric Acid	0.0360 LB/T	MACT	YES
Hydrogen Fluoride	0.2100 LB/T	MACT	YES
Nitrogen Oxides (NOx)	40.0000 LB/H	BACT-PSD	YES
Particulate matter, filterable < 10 µ (FPM10)	0.0100 G/DSCF	BACT-PSD	YES
Sulfur Dioxide (SO2)	34.2500 LB/H	BACT-PSD	YES
Volatile Organic Compounds (VOC)	0	BACT-PSD	YES

Process Notes:

http://cfpub.epa.gov/rblc/index.cfm?action=PermitDetail.ProcessInfo&facility_id=26286&PROCESS_ID=104420
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Process Information - Details

For information about the pollutants related to this process, click on the specific pollutant in the list below.

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Help

FINAL

RBLC ID: OK-0110
Corporate/Company: DALITALIA LLC
Facility Name: MUSKOGEE PORCELAIN FLOOR TILE PLT
Process: KILNS

Primary Fuel:
Throughput:
Process Code: 90.008

Pollutant Information - List of Pollutants

Help

Pollutant	Primary Emission Limit	Basis Verified
Carbon Monoxide	1.5500 LB/TON CLAY	UNKNOWN
Chlorine / Chlorine Compounds	0.0820 LB/TON TILE	UNKNOWN
Hydrochloric Acid	0.0820 LB/TON TILE	UNKNOWN
Hydrogen Fluoride	0.0820 LB/TON TILE	UNKNOWN
Particulate matter, filterable < 10 µ (FPM10)	0.0320 LB/TON TILE	UNKNOWN
Volatile Organic Compounds (VOC)	2.3500 LB/TON	UNKNOWN

Process Notes:

http://cfpub.epa.gov/rblc/index.cfm?action=PermitDetail.ProcessInfo&facility_id=22987&PROCESS_ID=93145
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Process Information - Details

For information about the pollutants related to this process, click on the specific pollutant in the list below.

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Help

FINAL

RBLC ID: GA-0074
Corporate/Company: DRY BRANCH KAOLIN CO.
Facility Name: DRY BRANCH KAOLIN CO.
Process: CALCINER NO. 4

Pollutant Information - List of Pollutants

Help

Primary Fuel: FUEL OIL
Throughput:
Process Code: 90.008

Pollutant	**Primary Emission Limit**	**Basis**	**Verified**
Nitrogen Oxides (NOx)	40.0000 TONS/12 CONSEC. MOS.	BACT-PSD	NO
Particulate Matter (PM)	0.0400 GR/DSCF	BACT-PSD	NO
Sulfur Oxides (SOx)	40.0000 TONS/12 CONSEC. MOS.	BACT-PSD	NO
Visible Emissions (VE)	10.0000 % OPACITY	BACT-PSD	NO

Process Notes: FUEL OIL CONSUMPTION IS LIMITED TO 44,890 GALLONS DURING ANY 12 CONSECUTIVE MONTH PERIOD

http://cfpub.epa.gov/rblc/index.cfm?action=Results.PermitSearchResults
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RBLC Search Results

List of Reports Help

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Please note that the use of your browser's BACK button to change the search conditions may result in inaccurate results.

Matching Facilities for Search Criteria : Tips
Permit Date Between 1/1/1990 And 07/15/2011
And Process Type = 90.009

These results are for USA only.

Check Un-Check **ALL Facilities** New Search

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLC ID	CORPORATE/COMPANY & FACILITY NAME	PROCESS CODE	PROCESS DESCRIPTION	PERMIT NUMBER & PERMIT DATE
Sort By	Sort By			Sort By
☑ NE-0047	ENDICOTT CLAY PRODUCTS ENDICOTT CLAY PRODUCTS	90.009	PLANT 3, KILN 1	CP03-0042 04/08/2008
		90.009	PLANT 3, DRYER 1	
☑ OK-0111	DALITALIA LLC MUSKOGEE PORCELAIN FLOOR TILE PLT	90.009	VERTICAL DRYERS	2004-198-C (M-1) 10/14/2005
		90.009	MATERIALS HANDLING	
		90.009	GLAZE/BODY PREP	
		90.009	SPRAY DRYERS	
		90.009	KILNS	
☑ IA-0054	BUNGE CORPORATION BUNGE CORPORATION	90.009	CLAY / D.E. TRANSFER CONVEYOR - R8	97-A-419, ET-AL. 05/20/1997
		90.009	CLAY SILO R5	

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○ Process Type Summary(with Agency Contact Info) ● TXT ○ pdf
○ Comprehensive Report ● TXT ○ pdf
○ Free Form Report(Customizable Fields Selection)
○ Free Form Report ● TXT ○ pdf
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Process Information - Details

For information about the pollutants related to this process, click on the specific pollutant in the list below.

RBLC Home | New Search | Search Results | Facility Information | Process List | Process Information

Help

FINAL

RBLC ID: NE-0047
Corporate/Company: ENDICOTT CLAY PRODUCTS
Facility Name: ENDICOTT CLAY PRODUCTS
Process: PLANT 3, KILN 1

Primary Fuel: NATURAL GAS
Throughput: 8.84 T/H
Process Code: 90.009

Pollutant Information - List of Pollutants

Help

Pollutant	Primary Emission Limit	Basis	Verified
Fluorides, Total	5.2200 LB/H	BACT-PSD	UNKNOWN
Particulate Matter (PM)	8.4900 LB/H	BACT-PSD	UNKNOWN

Process Notes:

http://cfpub.epa.gov/rblc/index.cfm?action=PermitDetail.ProcessInfo&facility_id=26397&PROCESS_ID=104616
Last updated on Friday, July 15, 2011

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Process Information - Details

For information about the pollutants related to this process, click on the specific pollutant in the list below.

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Help

FINAL

RBLC ID: OK-0111
Corporate/Company: DALITALIA LLC
Facility Name: MUSKOGEE PORCELAIN FLOOR TILE PLT
Process: KILNS

Pollutant Information - List of Pollutants

Help

Pollutant	Primary Emission Limit	Basis	Verified
Carbon Monoxide	1.9700 LB/H	BACT-PSD	UNKNOWN
Chlorine / Chlorine Compounds	0.0800 LB/T	BACT-PSD	UNKNOWN
Hydrochloric Acid	0.0800 LB/T	BACT-PSD	UNKNOWN
Hydrogen Fluoride	0.0800 LB/T	BACT-PSD	UNKNOWN
Particulate matter, filterable < 10 µ (FPM10)	0.3200 LB/T	BACT-PSD	UNKNOWN
Volatile Organic Compounds (VOC)	0.3200 LB/T	BACT-PSD	UNKNOWN

Primary Fuel:
Throughput:
Process Code: 90.009

Process Notes:

http://cfpub.epa.gov/rblc/index.cfm?action=PermitDetail.ProcessInfo&facility_id=26823&PROCESS_ID=106560
Last updated on Friday, July 15, 2011

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Process Information - Details

For information about the pollutants related to this process, click on the specific pollutant in the list below.

RBLC Home | New Search | Search Results | Facility Information | Process List | Process Information

Help

FINAL

RBLC ID:	NE-0047
Corporate/Company:	ENDICOTT CLAY PRODUCTS
Facility Name:	ENDICOTT CLAY PRODUCTS
Process:	PLANT 3, DRYER 1

Primary Fuel:	NATURAL GAS
Throughput:	8.84 T/H
Process Code:	90.009

Pollutant Information - List of Pollutants

Help

Pollutant	**Primary Emission Limit**	**Basis**	**Verified**
Particulate Matter (PM)	1.6500 LB/H	BACT-PSD	UNKNOWN

Process Notes: WASTE HEAT FROM PLANT 3, KILN 1 AND A SUPPLEMENTAL NATURAL GAS-FIRED BURNER PROVIDE THE HEAT FOR THE DRYER

http://cfpub.epa.gov/rblc/index.cfm?action=PermitDetail.ProcessInfo&facility_id=26397&PROCESS_ID=104615
Last updated on Friday, July 15, 2011

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Process Information - Details

For information about the pollutants related to this process, click on the specific pollutant in the list below.

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Help

FINAL

RBLC ID: OK-0111
Corporate/Company: DALITALIA LLC
Facility Name: MUSKOGEE PORCELAIN FLOOR TILE PLT
Process: VERTICAL DRYERS

Primary Fuel:
Throughput:
Process Code: 90.009

Pollutant Information - List of Pollutants

Help

Pollutant	Primary Emission Limit	Basis	Verified
Carbon Monoxide	1.2700 LB/H	BACT-PSD	UNKNOWN
Chlorine / Chlorine Compounds	0.0020 LB/H	BACT-PSD	UNKNOWN
Hydrochloric Acid	0.0020 LB/H	BACT-PSD	UNKNOWN
Hydrogen Fluoride	0.0020 LB/H	BACT-PSD	UNKNOWN
Particulate matter, filterable < 10 µ (FPM10)	0.7600 LB/H	BACT-PSD	UNKNOWN
Volatile Organic Compounds (VOC)	5.1100 LB/H	BACT-PSD	UNKNOWN

Process Notes:

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Process Information - Details

For information about the pollutants related to this process, click on the specific pollutant in the list below.

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FINAL

RBLC ID: OK-0111
Corporate/Company: DALITALIA LLC
Facility Name: MUSKOGEE PORCELAIN FLOOR TILE PLT
Process: SPRAY DRYERS

Primary Fuel:
Throughput:
Process Code: 90.009

Pollutant Information - List of Pollutants

Help

Pollutant	Primary Emission Limit	Basis	Verified
Carbon Monoxide	0.2300 LB/T	BACT-PSD	UNKNOWN
Chlorine / Chlorine Compounds	0.0030 LB/T	BACT-PSD	UNKNOWN
Hydrochloric Acid	0.0030 LB/T	BACT-PSD	UNKNOWN
Hydrogen Fluoride	0.0030 LB/T	BACT-PSD	UNKNOWN
Particulate matter, filterable < 10 µ (FPM10)	0.0170 G/DSCF	BACT-PSD	UNKNOWN
Volatile Organic Compounds (VOC)	0.2500 LB/T	BACT-PSD	UNKNOWN

Process Notes:

RBLC Search Results

List of Reports Help

Your search has found **14** facilities and **30** processes that match your search criteria. You can view details for one or more facilities by clicking on the highlighted RBLC identifier or the process description in the list below. To create a report, select one of the standard output formats from the list of reports at the bottom of this page. Only facilities that are checked in the table below will be included in your report. Click on the check box next to any facility to switch between checked and unchecked or use the "Check" or "Un-Check" all facilities buttons at the top of the list to check or uncheck all records in the list.

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Matching Facilities for Search Criteria :

Tips

Permit Date Between 1/1/1990 And 07/15/2011
And Process Type = 90.017

These results are for USA only.

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NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

	RBLC ID	CORPORATE/COMPANY & FACILITY NAME	PROCESS CODE	PROCESS DESCRIPTION	PERMIT NUMBER & PERMIT DATE
	Sort By	Sort By			Sort By
☑	TX-0536	SEADRIFT COKE SEADRIFT COKE	90.017	CALCINERS PETROLEUM	PSD-TX-410 04/20/2009
☑	OK-0110	DALITALIA LLC MUSKOGEE PORCELAIN FLOOR TILE PLT	90.017	VERTICAL DRYERS	2004-198-TV 10/21/2005
			90.017	SPRAY DRYERS	
☑	GA-0129	IMERYS / C.E. MINERALS C.E. MINERALS PLANT	90.017	BAUXITE GRINDING CIRCUIT	3295-261-0047-V-04-2 03/09/2005
☑	TX-0253	AKZO NOBEL CHEMICALS, INC. AKZO NOBEL CHEMICALS, INC.	90.017	CALCINER	9402 06/20/2000
☑	WY-0055	WOLD TRONA COMPANY, INC. WOLD TRONA COMPANY, INC.	90.017	FUEL TAMK VAPOR LOSSES (F2)	MD-455 04/27/2000
			90.017	TRONA ORE CALCINER STACK (E5) (E15)	
			90.017	BENETRON ORE UPGRADE FACILITY STACK (E4)	
☑	AR-0025	GENERAL SHALE PRODUCTS CORPORATION, LLC GENERAL SHALE PRODUCTS CORPORATION, LLC	90.017	KILN, AGGREGATE	280-AOP-R0 05/06/1999
	WY-0034	SOLVAY SODA ASH JOINT	90.017	CONVEYOR DISCHARGE, RECLAIM	CT-1347

☑	VENTURE TRONA MINE/SODA ASH SOLVAY SODA ASH JOINT VENTURE TRONA MINE/SODA ASH		TRONA ORE	02/06/1998
		90.017	SODA ASH NATURAL GAS, DRYER	
		90.017	CALCINER, NATURAL GAS FIRED TRONA	
		90.017	PRIMARY SCREENS, TRONA ORE	
		90.017	PRODUCT HANDLING AREA, SODA ASH DRYER PRODUCT	
		90.017	DIN VENTS & PRODUCT TRANSFER POINTS, (2) SODA ASH	
☑ CA-0808	CELITE CORPORATION CELITE CORPORATION	90.017	DIATOMACEOUS EARTH CALCINER	9757 12/05/1997
☑ WY-0031	GENERAL CHEM SODA ASH PARTNERS - GEN CHEM SODA GENERAL CHEM SODA ASH PARTNERS - GEN CHEM SODA	90.017	DRYER, TRONA, 6 EACH	MD-340 11/21/1997
		90.017	CALCINER, TRONA, 2 EACH	
		90.017	CALCINER, TRONA, 5 EACH	
		90.017	DRYER, TRONA, 6 EACH	
☑ WY-0035	TEXASGULF SODA ASH PLANT TEXASGULF SODA ASH PLANT	90.017	ROTARY DRYER, SODA ASH	CT-1321 10/13/1997
☑ WY-0036	OCI, WYOMING L.P.-OCI SODA ASH PLANT OCI, WYOMING L.P.-OCI SODA ASH PLANT	90.017	MATL. HANDLING & PROCESSING DRY ORE & SODA ASH	CT-1299 05/27/1997
		90.017	ROTARY DRYER, SODA ASH, NATURAL GAS FIRED	
		90.017	CALCINER TRONA ORE, NATURAL GAS FIRED	
		90.017	COOLER/CLASSIFIER	
		90.017	STORAGE SILOS, CARBON AND FILTER AID, (2 EA)	
☑ WY-0038	WOLD TRONA CO. WOLD TRONA CO.	90.017	CALCINER & CALCINER BOILER, (2)	CT-1148 05/02/1995
☑ GA-0059	THIELE KAOLIN CO. THIELE KAOLIN CO.	90.017	KAOLIN PROCESSING FACILITIES	3295-062-4465-0 01/24/1995
☑ WY-0028	FMC WY CORPORATION-GREEN RIVER SODA ASH PLANT FMC WY CORPORATION-GREEN RIVER SODA ASH PLANT	90.017	MATL. HANDLING, CONVEOR & TRANSFER	CT-1045 09/07/1993
		90.017	FLUID BED SODA ASH	

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○ Process Index Report ● TXT ○ pdf

○ Process Type Summary(with Agency Contact Info) ● TXT ○ pdf

○ Comprehensive Report ● TXT ○ pdf

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○ Free Form Report ● TXT ○ pdf

○ Export/Import Report(ASCII Delineated Text)

Create report

Process Information - Details

For information about the pollutants related to this process, click on the specific pollutant in the list below.

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FINAL

RBLC ID: TX-0536
Corporate/Company: SEADRIFT COKE
Facility Name: SEADRIFT COKE
Process: CALCINERS PETROLEUM

Primary Fuel: NATURAL GAS
Throughput: 1340.00 T/D
Process Code: 90.017

Pollutant Information - List of Pollutants

Help

Pollutant	Primary Emission Limit	Basis	Verified
Nitrogen Dioxide (NO2)	415.0000 T/YR	BACT-PSD	UNKNOWN
Sulfur Dioxide (SO2)	957.0000 T/YR	BACT-PSD	UNKNOWN

Process Notes: SEADRIFT COKE IS REQUESTING AN AMENDMENT TO BUILD A NEW DECANT HYDROGEN DESULFURIZATION UNIT (HDS) TO REDUCE FEEDSTOCK SULFUR LEVELS. THEY WILL ALSO BUILD A NEW HYDROGEN PLANT TO PROVIDE HYDROGEN TO THE HDS UNIT, SOUR WATER STORAGE, SOUR WATER STRIPPING, AMINE SYSTEM AND SUFLUR RECOVERY UNIT. A 2ND KILN WILL BE ADDED.

http://cfpub.epa.gov/rblc/index.cfm?action=PermitDetail.ProcessInfo&facility_id=24998&PROCESS_ID=98357
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Process Information - Details

For information about the pollutants related to this process, click on the specific pollutant in the list below.

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Help

FINAL

RBLC ID: TX-0253
Corporate/Company: AKZO NOBEL CHEMICALS, INC.
Facility Name: AKZO NOBEL CHEMICALS, INC.
Process: CALCINER

Primary Fuel:
Throughput: 40.00 MMBTU/H
Process Code: 90.017

Pollutant Information - List of Pollutants

Help

Pollutant	Primary Emission Limit	Basis	Verified
Nitrogen Oxides (NOx)	0.0660 LB/MMBTU	LAER	YES

Process Notes: THE SCC CODE WAS CHOSEN BASED ON THE ASSUMPTION THAT THE CALCINER IS USED AS PART OF A PETROLEUM REFINING PROCESS.

http://cfpub.epa.gov/rblc/index.cfm?action=PermitDetail.ProcessInfo&facility_id=23384&PROCESS_ID=94433
Last updated on Friday, July 15, 2011

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Process Information - Details

For information about the pollutants related to this process, click on the specific pollutant in the list below.

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FINAL

RBLC ID: WY-0055
Corporate/Company: WOLD TRONA COMPANY, INC.
Facility Name: WOLD TRONA COMPANY, INC.
Process: TRONA ORE CALCINER STACK (E5) (E15)

Primary Fuel: NATURAL GAS
Throughput: 212020.00 ACFM
Process Code: 90.017

Pollutant Information - List of Pollutants

Help

Pollutant	Primary Emission Limit	Basis	Verified
Nitrogen Oxides (NOx)	0.0380 LB/MMBTU	BACT-PSD	NO
Particulate matter, filterable < 10 µ (FPM10)	0.0030 GR/DSCF	BACT-PSD	NO

Process Notes: THROUGHPUT: 111,204 SCFM. EXHAUST FROM WET SCRUBBER (E11) CONTROLLING EMISSIONS FROM #1 FLUID BED CALCINER AND PORTION OF EMISSIONS FROM 460,000 LB/H STEAM RATE BOILER (E12). PHASE 2 WILL ADD STREAM E15 FROM SECOND SET OF ORE PROCESSING EQUIPMENT. NO PERMIT EMISSION LIMITS ON CO AND VOC.

http://cfpub.epa.gov/rblc/index.cfm?action=PermitDetail.ProcessInfo&facility_id=16262&PROCESS_ID=90436
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Process Information - Details

For information about the pollutants related to this process, click on the specific pollutant in the list below.

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FINAL

RBLC ID: AR-0025
Corporate/Company: GENERAL SHALE PRODUCTS CORPORATION, LLC
Facility Name: GENERAL SHALE PRODUCTS CORPORATION, LLC
Process: KILN, AGGREGATE

Pollutant Information - List of Pollutants

Help

Primary Fuel: NATURAL GAS
Throughput: 10.40 T/H
Process Code: 90.017

Pollutant	Primary Emission Limit	Basis	Verified
Carbon Monoxide	9.7000 LB/H	BACT-PSD	NO
Nitrogen Oxides (NOx)	8.5000 LB/H	BACT-PSD	NO
Particulate matter, filterable < 10 µ (FPM10)	21.9000 T/YR	BACT-PSD	NO
Sulfur Dioxide (SO2)	4.9000 T/YR	BACT-PSD	NO

Process Notes: THROUGHPUT IS T/H OF CLAY. COMPLIANCE WILL BE STACK TESTING. PERMIT SETS LIMITS FOR PM10, SO2, CO AND NOX.

http://cfpub.epa.gov/rblc/index.cfm?action=PermitDetail.ProcessInfo&facility_id=4126&PROCESS_ID=1
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Clean Air Technology Center - RACT/BACT/LAER Clearinghouse

You are here: EPA Home Air & Radiation TTNWeb - Technology Transfer Network Clean Air Technology Center RACT/BACT/LAER Clearinghouse RBLC Basic Search RBLC Search Results Process Information - Details

Process Information - Details

For information about the pollutants related to this process, click on the specific pollutant in the list below.

RBLC Home | New Search | Search Results | Facility Information | Process List | Process Information

Help

FINAL

RBLC ID: WY-0034
Corporate/Company: SOLVAY SODA ASH JOINT VENTURE TRONA MINE/SODA ASH
Facility Name: SOLVAY SODA ASH JOINT VENTURE TRONA MINE/SODA ASH
Process: CALCINER, NATURAL GAS FIRED TRONA

Primary Fuel: NATURAL GAS
Throughput: 275.00 T/H TRONA ORE FEED
Process Code: 90.017

Pollutant Information - List of Pollutants

Help

Pollutant	Primary Emission Limit	Basis	Verified
Nitrogen Oxides (NOx)	0.0500 LB/MMBTU	BACT-PSD	NO
Particulate Matter (PM)	0.0150 GR/DSCF	BACT-PSD	NO
Volatile Organic Compounds (VOC)	533.5000 LB/H	BACT-PSD	NO

Process Notes:

Process Information - Details

For information about the pollutants related to this process, click on the specific pollutant in the list below.

RBLC Home | New Search | Search Results | Facility Information | Process List | Process Information

Help

FINAL

RBLC ID: CA-0808
Corporate/Company: CELITE CORPORATION
Facility Name: CELITE CORPORATION
Process: DIATOMACEOUS EARTH CALCINER

Primary Fuel: PUC NATURAL GAS
Throughput: 0
Process Code: 90.017

Pollutant Information - List of Pollutants

Help

Pollutant	Primary Emission Limit	Basis	Verified
Sulfur Oxides (SOx)	98.0000 % MASS REMOVAL	LAER	NO

Process Notes: ARB RECORD # A430-814-97

Process Information - Details

For information about the pollutants related to this process, click on the specific pollutant in the list below.

RBLC Home | New Search | Search Results | Facility Information | Process List | Process Information

Help

FINAL

RBLC ID: WY-0036
Corporate/Company: OCI, WYOMING L.P.-OCI SODA ASH PLANT
Facility Name: OCI, WYOMING L.P.-OCI SODA ASH PLANT
Process: CALCINER TRONA ORE, NATURAL GAS FIRED

Primary Fuel: NATURAL GAS
Throughput: 213.00 T/H ORE FEED RATE
Process Code: 90.017

Pollutant Information - List of Pollutants

Help

Pollutant	Primary Emission Limit	Basis	Verified
Nitrogen Oxides (NOx)	0.0500 LB/MMBTU	BACT-PSD	NO
Particulate Matter (PM)	0.0170 GR/DSCF	BACT-PSD	NO
Visible Emissions (VE)	20.0000 % OPACITY	Other Case-by-Case	NO
Volatile Organic Compounds (VOC)	44.0400 LB/H	BACT-PSD	NO

Process Notes:

http://cfpub.epa.gov/rblc/index.cfm?action=PermitDetail.ProcessInfo&facility_id=26286&PROCESS_ID=104419
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Process Information - Details

For information about the pollutants related to this process, click on the specific pollutant in the list below.

RBLC Home | New Search | Search Results | Facility Information | Process List | Process Information

Help

FINAL

RBLC ID: OK-0110
Corporate/Company: DALITALIA LLC
Facility Name: MUSKOGEE PORCELAIN FLOOR TILE PLT
Process: VERTICAL DRYERS

Primary Fuel:
Throughput:
Process Code: 90.017

Pollutant Information - List of Pollutants

Help

Pollutant	Primary Emission Limit	Basis Verified
Carbon Monoxide	1.0600 LB/H	UNKNOWN
Chlorine / Chlorine Compounds	0.0011 LB/TON MATERIAL	UNKNOWN
Hydrochloric Acid	0.0011 LB/TON MATERIAL	UNKNOWN
Hydrogen Fluoride	0.0011 LB/TON MATERIAL	UNKNOWN
Particulate matter, filterable < 10 µ (FPM10)	0.0800 LB/DSCF	UNKNOWN
Volatile Organic Compounds (VOC)	4.2600 LB/H	UNKNOWN

Process Notes:

http://cfpub.epa.gov/rblc/index.cfm?action=PermitDetail.ProcessInfo&facility_id=26286&PROCESS_ID=104418
Last updated on Friday, July 15, 2011

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Process Information - Details

For information about the pollutants related to this process, click on the specific pollutant in the list below.

RBLC Home | New Search | Search Results | Facility Information | Process List | Process Information

Help

FINAL

RBLC ID: OK-0110
Corporate/Company: DALITALIA LLC
Facility Name: MUSKOGEE PORCELAIN FLOOR TILE PLT
Process: SPRAY DRYERS

Pollutant Information - List of Pollutants

Help

Pollutant	Primary Emission Limit	Basis Verified
Carbon Monoxide	0.3660 LB/TON	UNKNOWN
Chlorine / Chlorine Compounds	0.0030 LB/TON	UNKNOWN
Hydrochloric Acid	0.0030 LB/TON	UNKNOWN
Hydrogen Fluoride	0.0030 LB/TON	UNKNOWN
Particulate matter, filterable < 10 µ (FPM10)	0.0180 G/DSCF	UNKNOWN
Volatile Organic Compounds (VOC)	0.2500 LB/TON MATERIAL	UNKNOWN

Primary Fuel:
Throughput:
Process Code: 90.017

Process Notes:

http://cfpub.epa.gov/rblc/index.cfm?action=PermitDetail.ProcessInfo&facility_id=4128&PROCESS_ID=2
Last updated on Friday, July 15, 2011

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Process Information - Details

For information about the pollutants related to this process, click on the specific pollutant in the list below.

RBLC Home | New Search | Search Results | Facility Information | Process List | Process Information

Help

FINAL

RBLC ID: WY-0036
Corporate/Company: OCI, WYOMING L.P.-OCI SODA ASH PLANT
Facility Name: OCI, WYOMING L.P.-OCI SODA ASH PLANT
Process: ROTARY DRYER, SODA ASH, NATURAL GAS FIRED

Primary Fuel: NATURAL GAS
Throughput: 144.00 T/H WET CRYSTAL FEED
Process Code: 90.017

Pollutant Information - List of Pollutants

Help

Pollutant	Primary Emission Limit	Basis	Verified
Nitrogen Oxides (NOx)	0.1500 LB/MMBTU	BACT-PSD	NO
Particulate Matter (PM)	0.0170 GR/SCF	BACT-PSD	NO
Visible Emissions (VE)	20.0000 % OPACITY	Other Case-by-Case	NO
Volatile Organic Compounds (VOC)	0.3700 LB/H	BACT-PSD	NO

Process Notes: UNIT 6ES-12

APPENDIX F – PERMIT APPLICATION FORMS

State of Georgia
Department of Natural Resources
Environmental Protection Division
Air Protection Branch

Stationary Source Permitting Program
4244 International Parkway, Suite 120
Atlanta, Georgia 30354
404/363-7000
Fax: 404/363-7100

SIP AIR PERMIT APPLICATION

EPD Use Only

Date Received: ____________________ Application No. ____________________

FORM 1.00: GENERAL INFORMATION

1. Facility Information

Facility Name: King's Mill Facility
AIRS No. (if known): 04-13- -
Facility Location: Street: County Road 291
City: Wrens Georgia Zip: 30833 County: Jefferson

2. Facility Coordinates

Latitude: 33° 10' 05" **NORTH** Longitude: 82° 22' 03" **WEST**
UTM Coordinates: 372,483.08 **EAST** 3,670,754.832 **NORTH** **ZONE** 17S

3. Facility Owner

Name of Owner: PyraMax Ceramics, LLC
Owner Address Street: County Road 291
City: Wrens State: GA Zip: 30833

4. Permitting Contact and Mailing Address

Contact Person: Michael Burgess Title: Vice President of Manufacturing
Telephone No.: 478-234-8178 Ext. ______ Fax No.: ______
Email Address: m.burgess@pyramaxceramics.com
Mailing Address: Same as: Facility Location: ☐ Owner Address: ☐ Other: ☒
If Other: Street Address: 161 Britt Waters Rd, NW
City: Milledgeville State: GA Zip: 31061

5. Authorized Official

Name: Don A. Anschutz Title: President
Address of Official Street: 17515 Spring Cypress Rd. Suite C#253
City: Cypress State: TX Zip: 77429

This application is submitted in accordance with the provisions of the Georgia Rules for Air Quality Control and, to the best of my knowledge, is complete and correct.

Signature: ____________________ Date: 7/21/2011

6. **Reason for Application: (Check all that apply)**

☒ New Facility (to be constructed)

☐ Existing Facility (initial or modification application)

☐ Permit to Construct

☐ Permit to Operate

☐ Change of Location

☐ Permit to Modify Existing Equipment: Affected Permit No.: ______

☐ Revision of Data Submitted in an Earlier Application

Application No.: ______

Date of Original Submittal: ______

7. **Permitting Exemption Activities (for permitted facilities only):**

Have any exempt modifications based on emission level per Georgia Rule 391-3-1-.03(6)(i)(3) been performed at the facility that have not been previously incorporated in a permit?

☒ **No** ☐ **Yes, please fill out the SIP Exemption Attachment** (See Instructions for the attachment download)

8. **Has assistance been provided to you for any part of this application?**

☐ **No** ☐ **Yes, SBAP** ☒ **Yes, a consultant has been employed or will be employed.**

If yes, please provide the following information:

Name of Consulting Company: Trinity Consultants, Inc.

Name of Contact: Justin Fickas

Telephone No.: 678-441-9977 Fax No.: 678-441-9978

Email Address: jfickas@trinityconsultants.com

Mailing Address: Street: 53 Perimeter Center East, Suite 230

City: Atlanta State: GA Zip: 30346

Describe the Consultant's Involvement:

Assisted in preparation of the application.

9. **Submitted Application Forms:** Select only the necessary forms for the facility application that will be submitted.

No. of Forms	Form
4	2.00 Emission Unit List
1	2.01 Boilers and Fuel Burning Equipment
1	2.02 Storage Tank Physical Data
	2.03 Printing Operations
	2.04 Surface Coating Operations
	2.05 Waste Incinerators (solid/liquid waste destruction)
1	2.06 Manufacturing and Operational Data
3	3.00 Air Pollution Control Devices (APCD)
	3.01 Scrubbers
2	3.02 Baghouses & Other Filter Collectors
	3.03 Electrostatic Precipitators
10	4.00 Emissions Data
1	5.00 Monitoring Information
	6.00 Fugitive Emission Sources
2	7.00 Air Modeling Information

10. **Construction or Modification Date**

Estimated Start Date: June 2012

11. If confidential information is being submitted in this application, were the guidelines followed in the "Procedures for Requesting that Submitted Information be treated as Confidential"?

☐ No ☐ Yes

12. New Facility Emissions Summary

Criteria Pollutant	**New Facility**	
	Potential (tpy)	**Actual (tpy)**
Carbon monoxide (CO)	608.10	608.10
Nitrogen oxides (NOx)	350.78	350.78
Particulate Matter (PM)	156.88	156.88
PM <10 microns (PM10)	156.88	156.88
PM <2.5 microns (PM2.5)	106.52	106.52
Sulfur dioxide (SO_2)	102.71	102.71
Volatile Organic Compounds (VOC)	129.73	129.73
Total Hazardous Air Pollutants (HAPs)	126.88	126.88
Individual HAPs Listed Below:		
Methanol	53.51	53.51
n-Hexane	2.11	2.11
Hydrogen fluoride	9.04	9.04
Hydrogen chloride	5.89	5.89
*For information on additional HAPs, please see calculations in Appendix C		

13. Existing Facility Emissions Summary

Criteria Pollutant	**Current Facility**		**After Modification**	
	Potential (tpy)	**Actual (tpy)**	**Potential (tpy)**	**Actual (tpy)**
Carbon monoxide (CO)				
Nitrogen oxides (NOx)				
Particulate Matter (PM)				
PM <10 microns (PM10)				
PM <2.5 microns (PM2.5)				
Sulfur dioxide (SO_2)				
Volatile Organic Compounds (VOC)				
Total Hazardous Air Pollutants (HAPs)				
Individual HAPs Listed Below:				

14. 4-Digit Facility Identification Code:

SIC Code: 3295 SIC Description: Minerals and Earths, Ground or Otherwise Treated

NAICS Code: 212324 NAICS Description: Kaolin and Ball Clay Mining

15. Description of general production process and operation for which a permit is being requested. If necessary, attach additional sheets to give an adequate description. Include layout drawings, as necessary, to describe each process. References should be made to source codes used in the application.

See process description included within the application text.

16. Additional information provided in attachments as listed below:

Attachment A - Area Map and Plot (Appendix A)
Attachment B - Process Flow Diagram (Appendix B)
Attachment C - Detailed Emissions Calculations (Appendix C)
Attachment D - BACT Supporting Information (Appendix D)
Attachment E - Case-By-Case MACT Supporting Information (Appendix E)
Attachment F - Permit Application Forms (Appendix F)
Attachment G - MSDS/Raw Material Information (Appendix G)

17. Additional Information: Unless previously submitted, include the following two items:

☒ Plot plan/map of facility location or date of previous submittal: See Appendix A
☒ Flow Diagram or date of previous submittal: See Appendix B

Emission Unit Description	Emission Unit ID in Calcs	Emission Unit ID in GA SIP Forms	Modeled Emission Point ID	Emission Point ID in GA SIP Forms	Baghouse ID in GA SIP Forms
Feed Bin	12-03-1162	FB1	12-12-1163	SV10	BV10
Kiln Dust Recycle to Feed Bin	14-07-1410	KDR1	12-12-1170	SBD1	BHD1
Additive Silos - Line 1&2		ADS1	PVA1	SVS1	BVS1
Pelletizer, Conveyor under Pelletizer, Conveyor to Feed Bin, Elevator to Green Pellet Screening	12-27-1100, 12-07-1160, 12-07-1161, 12-13-1105	PEL1, CP1, CSB1, EGP1	12-12-1141	SBP1	BHP1
Feed Bin	22-03-1162	FB2	22-12-1163	SV20	BV20
Kiln Dust Recycle to Feed Bin	24-07-1410	KDR2	22-12-1170	SBD2	BHD2
Pelletizer, Conveyor under Pelletizer, Conveyor to Feed Bin, Elevator to Green Pellet Screening	22-27-1100, 22-07-1160, 22-07-1161, 22-13-1105	PEL2, CP2, CSB2, EGP2	22-12-1141	SBP2	BHP2
Oversize Surge Bin	13-03-1210	OSB1	13-12-1211		
Undersize Surge Bin	13-03-1204	USB1	13-12-1205		
Green Pellet Screen #1, Green Pellet Screen #2, Oversize Elevator, Reversing Belt Conveyor, Kiln Feed Elevator	13-24-1190, 13-24-1191, 13-13-1213, 13-07-1207, 13-13-1208	GS11, GS12, OE1, RBC1, KFE1	13-12-1215	SBG1	BHG1
Cage Mill, Cyclone, Screw Conveyor	13-19-1220, 13-09-1221, 13-07-1225	CM1, CYC1, SC1	13-12-1224	SBM1	BHM1
Oversize Surge Bin	23-03-1210	OSB2	23-12-1211		
Undersize Surge Bin	23-03-1204	USB2	23-12-1205		
Green Pellet Screen #1, Green Pellet Screen #2, Oversize Elevator, Reversing Belt Conveyor, Kiln Feed Elevator	23-24-1190, 23-24-1191, 23-13-1213, 23-07-1207, 23-13-1208	GS21, GS22, OE2, RBC2, KFE2	23-12-1215	SBG2	BHG2
Cage Mill, Cyclone, Screw Conveyor	23-19-1220, 23-09-1221, 23-07-1225	CM2, CYC2, SC2	23-12-1224	SBM2	BHM2
Kiln Feed Bin	14-03-1400	KFB1	14-12-1401		
Kiln Recycle Feed Bin	14-03-1485	KRF1	14-12-1486	SV11	BV11
Kiln Recycle Elevator, Weigh Belt	14-13-1484, 14-23-1403	KRW1	14-12-1432		
Kiln, Kiln Cooler, Grizzly	14-21-1410, 14-21-1430, 14-21-1420	KLN1, KC1, GRZ1	14-12-1412	SBK1	BHK1
Kiln Feed Bin	24-03-1400	KFB2	24-12-1401		
Kiln Recycle Feed Bin	24-03-1485	KRF2	24-12-1486	SV21	BV21

Emission Unit Description	Emission Unit ID in Calcs	Emission Unit ID in GA SIP Forms	Modeled Emission Point ID	Emission Point ID in GA SIP Forms	Baghouse ID in GA SIP Forms
Kiln Recycle Elevator, Weigh Belt	24-13-1484, 24-23-1403	KRW2	24-12-1432		
Kiln, Kiln Cooler, Grizzly	24-21-1410, 24-21-1430, 24-21-1420	KLN2, KC2, GRZ2	24-12-1412	SBK2	BHK2
Product QC Bin #1	15-03-1441	QC11	15-12-1442		
Product QC Bin #2	15-03-1445	QC12	15-12-1446		
Product QC Bin #3	15-03-1461	QC13	15-12-1462		
Product QC Bin #4	15-03-1465	QC14	15-12-1466		
Recycle Weigh Bin	15-03-1480	RWB1	15-12-1481		
Cooler Elevator, Final Product Screen #1, Final Product Screen #2, Final Product Screen #3, Final Product Screen #4, Reversing Weigh Belt, Reversing Weigh Belt, Recycle Elevator	14-21-1431, 15-24-1439, 15-24-1440, 15-24-1459, 15-24-1460, 15-07-1448, 15-07-1468, 15-21-1491	CE1, FS11, FS12, FS13, FS14, RB11, RB12, RE1	15-12-1488	SBF1	BHF1
Product QC Bin #1	25-03-1441	QC21	25-12-1442		
Product QC Bin #2	25-03-1445	QC22	25-12-1446		
Product QC Bin #3	25-03-1461	QC23	25-12-1462		
Product QC Bin #4	25-03-1465	QC24	25-12-1466		
Recycle Weigh Bin	25-03-1480	RWB2	25-12-1481		
Cooler Elevator, Final Product Screen #1, Final Product Screen #2, Final Product Screen #3, Final Product Screen #4, Reversing Weigh Belt, Reversing Weigh Belt, Recycle Elevator	24-21-1431, 25-24-1439, 25-24-1440, 25-24-1459, 25-24-1460, 25-07-1448, 25-07-1468, 25-21-1491	CE2, FS21, FS22, FS23, FS24, RB21, RB22, RE2	25-12-1488	SBF2	BHF2
Silo #1	16-03-1520	S11	16-12-1521	SV12	BV12
Silo #2	16-03-1530	S12	16-12-1531	SV13	BV13
Silo #3	16-03-1540	S13	16-12-1541	SV14	BV14
Silo #4	16-03-1550	S14	16-12-1551	SV15	BV15
Silo #5	16-03-1560	S15	16-12-1561	SV16	BV16
Weigh Bin	16-03-1572	WB1	16-12-1573	SV17	BV17
Belt Conveyor, Loading Elevator, Loading Spout	16-07-1570, 16-07-1571, 16-18-1576	BC1, LE1, LS1	16-12-1580	SBL1	BHL1
Silo #1	26-03-1520	S21	26-12-1521	SV22	BV22
Silo #2	26-03-1530	S22	26-12-1531	SV23	BV23
Silo #3	26-03-1540	S23	26-12-1541	SV24	BV24
Silo #4	26-03-1550	S24	26-12-1551	SV25	BV25
Silo #5	26-03-1560	S25	26-12-1561	SV26	BV26
Weigh Bin	26-03-1572	WB2	26-12-1573	SV27	BV27
Belt Conveyor, Loading Elevator, Loading Spout	26-07-1570, 26-07-1571, 26-18-1576	BC2, LE2, LS2	26-12-1580	SBL2	BHL2
Sodium bicarbonate silo		SBS1	S1a	SV18	BV18
Fly Ash Silo		FAS1	S1b	SV19	BV19
Sodium bicarbonate silo		SBS2	S2a	SV28	BV28
Fly Ash Silo		FAS2	S2b	SV29	BV29

Emission Unit Description	Emission Unit ID in Calcs	Emission Unit ID in GA SIP Forms	Modeled Emission Point ID	Emission Point ID in GA SIP Forms	Baghouse ID in GA SIP Forms
Boiler - Line 1	17-XX-XXX	B1	B1	STB1	
Boiler - Line 2	27-XX-XXX	B2	B2	STB2	
Generator - Line 1	17-XX-XXX	G1			
Generator - Line 2	27-XX-XXX	G2			
Diesel Storage Tank - Line 1		DST1			
Diesel Storage Tank - Line 2		DST2			
Diesel Storage Tank - 7000 gal		DST3			
Diesel Storage Tank - 1000 gal		DST4			

Facility Name: PyraMax Ceramics, LLC **Date of Application:** July 2011

FORM 2.00 – EMISSION UNIT LIST

Emission Unit ID	Name	Manufacturer and Model Number	Description
FB1, 2**	Feed Bin	TBD	Feed Bin
KDR1, 2	Kiln Dust Recycle to Feed Bin	TBD	Kiln Dust Recycle to Feed Bin
ADS1	Additive Silos–Lines 1&2	TBD	Additive Silos–Lines 1&2
PEL1,2	Pelletizer	TBD	Pelletizer
CP1, 2	Conveyor under Pelletizer	TBD	Conveyor under Pelletizer
CSB1, 2	Conveyor to Feed Bin	TBD	Conveyor to Feed Bin
EGP1, 2	Elevator to Green Pellet Screening	TBD	Elevator to Green Pellet Screening
OSB1, 2	Oversize Surge Bin	TBD	Oversize Surge Bin
USB1, 2	Undersize Surge Bin	TBD	Undersize Surge Bin
GP11, 21	Green Pellet Screen #1	TBD	Green Pellet Screen #1
GP12, 22	Green Pellet Screen #2	TBD	Green Pellet Screen #2
OE1, 2	Oversize Elevator	TBD	Oversize Elevator
RBC1, 2	Reversing Belt Conveyor	TBD	Reversing Belt Conveyor

**In all of the forms, when two units are listed together, the information given is for each unit.

Facility Name: PyraMax Ceramics, LLC **Date of Application:** July 2011

FORM 2.00 – EMISSION UNIT LIST

Emission Unit ID	Name	Manufacturer and Model Number	Description
KFE1, 2	Kiln Feed Elevator	TBD	Kiln Feed Elevator
CM1, 2	Cage Mill	TBD	Cage Mill
CYC1, 2	Cyclone	TBD	Cyclone
SC1, 2	Screw Conveyor	TBD	Screw Conveyor
KFB1, 2	Kiln Feed Bin	TBD	Kiln Feed Bin
KRF1, 2	Kiln Recycle Feed Bin	TBD	Kiln Recycle Feed Bin
KRW1, 2	Kiln Recycle Elevator & Weigh Belt	TBD	Kiln Recycle Elevator & Weigh Belt
KLN1, 2	Kiln	TBD	Natural gas and propane fired kilns at 49.3 MMBtu/hr
KC1, 2	Kiln Cooler	TBD	Kiln Cooler
GRZ1, 2	Grizzly	TBD	Grizzly
QC11, 21	Product QC Bin #1	TBD	Product QC Bin #1
QC12, 22	Product QC Bin #2	TBD	Product QC Bin #2
QC13, 23	Product QC Bin #3	TBD	Product QC Bin #3
QC14, 24	Product QC Bin #4	TBD	Product QC Bin #4
RWB1, 2	Recycle Weigh Bin	TBD	Recycle Weigh Bin
CE1, 2	Cooler Elevator	TBD	Cooler Elevator
FS11, 12	Final Product Screen #1	TBD	Final Product Screen #1
FS12, 22	Final Product Screen #2	TBD	Final Product Screen #2

Facility Name: PyraMax Ceramics, LLC **Date of Application:** July 2011

FORM 2.00 – EMISSION UNIT LIST

Emission Unit ID	Name	Manufacturer and Model Number	Description
FS13, 23	Final Product Screen #3	TBD	Final Product Screen #3
FS14, 24	Final Product Screen #4	TBD	Final Product Screen #4
RB11, 21	Reversing Weigh Belt	TBD	Reversing Weigh Belt
RB12, 22	Reversing Weigh Belt	TBD	Reversing Weigh Belt
RE1, 2	Recycle Elevator	TBD	Recycle Elevator
S11, 21	Silo #1	TBD	Silo #1
S12, 22	Silo #2	TBD	Silo #2
S13, 23	Silo #3	TBD	Silo #3
S14, 24	Silo #4	TBD	Silo #4
S15, 25	Silo #5	TBD	Silo #5
WB1, 2	Weigh Bin	TBD	Weigh Bin
BC1, 2	Belt Conveyor	TBD	Belt Conveyor
LE1, 2	Loading Elevator	TBD	Loading Elevator
LS1, 2	Loading Spout	TBD	Loading Spout
SBS1, 2	Sodium Bicarbonate Silo	TBD	Sodium Bicarbonate Silo
FAS1, 2	Fly Ash Silo	TBD	Fly Ash Silo
B1, 2	Boiler	TBD	Natural gas and propane fired boilers at 9.8 MMBtu/hr
G1, 2	Generator	TBD	Ultra low sulfur diesel, two diesel engines per generator, 500 kW per engine
DST1, 2	Diesel Storage Tanks	TBD	One 2,375 diesel generator storage tank per line

Facility Name: Pyramax Ceramics, LLC **Date of Application:** July 2011

FORM 2.00 – EMISSION UNIT LIST

Emission Unit ID	Name	Manufacturer and Model Number	Description
DST3	Diesel Storage Tank	TBD	One 7,000 gal diesel storage tank for the entire facility
DST4	Diesel Storage Tank	TBD	One 1,000 gal diesel storage tank for the entire facility

Facility Name: PyraMax Ceramics, LLC **Date of Application:** July 2011

FORM 2.01 – BOILERS AND FUEL BURNING EQUIPMENT

Emission Unit ID	Type of Burner	Type of Draft[1]	Design Capacity of Unit (MMBtu/hr Input)	Percent Excess Air	Dates		Date & Description of Last Modification
					Construction	Installation	
PEL1,2	Low NOx	N/A	75 MMBtu/hr	10	June 2012	June 2012	N/A
KLN1,2	Low NOx	N/A	49.3 MMBtu/hr	10	June 2012	June 2012	N/A
B1,2	Low NOx	N/A	9.8 MMBtu/hr	10	June 2012	June 2012	N/A
G1,2	N/A	N/A	9.4 MMBtu/hr	10	June 2012	June 2012	N/A

[1] This column does not have to be completed for natural gas only fired equipment.

Facility Name: PyraMax Ceramics LLC **Date of Application:** July 2011

FUEL DATA

Emission Unit ID	Fuel Type	Potential Annual Consumption				Hourly Consumption		Heat Content		Percent Sulfur		Percent Ash in Solid Fuel	
		Total Quantity		Percent Use by Season		Max.	Avg.	Min.	Avg.	Max.	Avg.	Max.	Avg.
		Amount	Units	Ozone Season May 1 - Sept 30	Non-ozone Season Oct 1 - Apr 30								
PEL1,2	**Natural Gas**	**657.00**	**MMscf/yr**	**42%**	**58%**	**0.075**	**0.075**	**1000 Btu/ft^3**	**1000 Btu/ft^3**	**Negligible**	**Negligible**	**N/A**	**N/A**
PEL1,2	**Propane**	**7,180.32**	**Mgal/yr**	**42%**	**58%**	**0.819**	**0.819**	**91.5 MMBtu/Mgal**	**91.5 MMBtu/Mgal**	**Negligible**	**Negligible**	**N/A**	**N/A**
KLN1,2	**Natural Gas**	**431.87**	**MMscf/yr**	**42%**	**58%**	**0.0493**	**0.0493**	**1000 Btu/ft^3**	**1000 Btu/ft^3**	**Negligible**	**Negligible**	**N/A**	**N/A**
KLN1,2	**Propane**	**4,719.87**	**Mgal/yr**	**42%**	**58%**	**0.539**	**0.539**	**91.5 MMBtu/Mgal**	**91.5 MMBtu/Mgal**	**Negligible**	**Negligible**	**N/A**	**N/A**
B1,2	**Natural Gas**	**85.85**	**MMscf/yr**	**42%**	**58%**	**0.0098**	**0.0098**	**1000 Btu/ft^3**	**1000 Btu/ft^3**	**Negligible**	**Negligible**	**N/A**	**N/A**
B1,2	**Propane**	**938.23**	**Mgal/yr**	**42%**	**58%**	**0.107**	**0.107**	**91.5 MMBtu/Mgal**	**91.5 MMBtu/Mgal**	**Negligible**	**Negligible**	**N/A**	**N/A**
G1,2	**Ultra-low sulfur diesel**	**586.92**	**Mgal/yr**	**42%**	**58%**	**0.067**	**0.067**	**140 MMBtu/Mgal**	**140 MMBtu/Mgal**	**0.0015**	**0.0015**	**N/A**	**N/A**

Fuel Supplier Information

Fuel Type	Name of Supplier	Phone Number	Supplier Location			
			Address	City	State	Zip
Natural Gas	**TBD**					
Propane	**TBD**					
Diesel	**TBD**					

Facility Name: PyraMax Ceramics, LLC **Date of Application:** July 2011

FORM 2.02 – ORGANIC COMPOUND STORAGE TANK

Emission Unit ID	Emission Unit Name	Capacity (gal)	Material Stored	Maximum True Vapor Pressure (psi @ ºF)	Storage Temp. (ºF)	Filling Method	Construction/ Modification Date	Roof Type	Seal Type
DST1	Diesel storage tank	2,375	Diesel	0.19 at 100F; negligible below that	Ambient	Submerged	TBD	TBD	TBD
DST2	Diesel storage tank	2,375	Diesel	0.19 at 100F; negligible below that	Ambient	Submerged	TBD	TBD	TBD
DST3	Diesel storage tank	7,000	Diesel	0.19 at 100F; negligible below that	Ambient	Submerged	TBD	TBD	TBD
DST4	Diesel storage tank	1,000	Diesel	0.19 at 100F; negligible below that	Ambient	Submerged	TBD	TBD	TBD

Facility Name: PyraMax Ceramics, LLC **Date of Application:** July 2011

FORM 2.06 – MANUFACTURING AND OPERATIONAL DATA

Normal Operating Schedule: 24 hours/day 7 days/week 52 weeks/yr

Additional Data Attached? ☐ - No ☒ - Yes, please include the attachment in list on Form 1.00, Item 16.

Seasonal and/or Peak Operating Periods: None

Dates of Annually Occurring Shutdowns: None

PRODUCTION INPUT FACTORS

Emission Unit ID	Emission Unit Name	Const. Date	Input Raw Material(s)	Annual Input	Hourly Process Input Rate		
					Design	Normal	Maximum
FB1, 2	Feed Bin/Tank	June 2012	Clay/Water/Grit/ Additives	635,000 tpy	145,000 lb/hr	174,000 lb/hr	174,000 lb/hr

PRODUCTS OF MANUFACTURING

Emission Unit ID	Description of Product	Production Schedule		Hourly Production Rate (Give units: e.g. lb/hr, ton/hr)			
		Tons/yr	Hr/yr	Design	Normal	Maximum	Units
LS1, 2	**Ceramic proppants**	**---**	**8760**	**---**	**---**	**---**	**lb/hr**
Production schedule and hourly production rates can be provided to GA EPD upon request.							

Baghouse Name	Modeled Emission Point ID	APCD Unit ID	Emission Unit ID
Feed Bin Vent Filter	12-12-1163	BV10	FB1
Baghouse- for dust from kiln baghouse to Feed Bin	12-12-1170	BHD1	KDR1
Additive Silo Bin Vent Lines 1 and 2	PVA1	BVS1	ADS1
Baghouse for pelletization	12-12-1141	BHP1	PEL1, CP1, CSB1, EGP1
Feed Bin Vent Filter	22-12-1163	BV20	FB2
Baghouse- for dust from kiln baghouse to Feed Bin	22-12-1170	BHD2	KDR2
Baghouse for pelletization	22-12-1141	BHP2	PEL2, CP2, CSB2, EGP2
Baghouse for Green Pellet Screening	13-12-1215	BHG1	GS11, GS12, OE1, RBC1, KFE1
Baghouse for Dry Milling	13-12-1224	BHM1	CM1, CYC1, SC1
Baghouse for Green Pellet Screening	23-12-1215	BHG2	GS21, GS22, OE2, RBC2, KFE2
Baghouse for Dry Milling	23-12-1224	BHM2	CM2, CYC2, SC2
Kiln Recycle Feed Bin Vent Filter	14-12-1486	BV11	KRF1
Baghouse for kiln recycle elevator and weigh belt (indoor baghouse)	14-12-1432	--	KRW1
Kiln Catalytic Baghouse	14-12-1412	BHK1	KLN1, KC1, GRZ1
Kiln Recycle Feed Bin Vent Filter	24-12-1486	BV21	KRF2
Baghouse for kiln recycle elevator and weigh belt (indoor baghouse)	24-12-1432	--	KRW2

Baghouse Name	Modeled Emission Point ID	APCD Unit ID	Emission Unit ID
Kiln Catalytic Baghouse	24-12-1412	BHK2	KLN2, KC2, GRZ2
Baghouse for Final Product Screening and QC	15-12-1488	BHF1	CE1, FS11, FS12, FS13, FS14, RB11, RB12, RE1
Baghouse for Final Product Screening and QC	25-12-1488	BHF2	CE2, FS21, FS22, FS23, FS24, RB21, RB22, RE2
Silo #1 Bin Vent Filter	16-12-1521	BV12	S11
Silo #2 Bin Vent Filter	16-12-1531	BV13	S12
Silo #3 Bin Vent Filter	16-12-1541	BV14	S13
Silo #4 Bin Vent Filter	16-12-1551	BV15	S14
Silo #5 Bin Vent Filter	16-12-1561	BV16	S15
Weigh Bin Bin Vent Filter	16-12-1573	BV17	WB1
Baghouse for Loading Operations	16-12-1580	BHL1	BC1, LE1, LS1
Silo #1 Bin Vent Filter	S21	BV22	S21
Silo #2 Bin Vent Filter	S22	BV23	S22
Silo #3 Bin Vent Filter	S23	BV24	S23
Silo #4 Bin Vent Filter	S24	BV25	S24
Silo #5 Bin Vent Filter	S25	BV26	S25
Weigh Bin Bin Vent Filter	WB2	BV27	WB2
Baghouse for Loading Operations	BC2, LE2, LS2	BHL2	BC2, LE2, LS2
Sodium Bicarbonate Silo Bin Vent Filter	S1a	BV18	SBS1
Fly Ash Silo Bin Vent Filter	S1b	BV19	FAS1
Sodium Bicarbonate Silo Bin Vent Filter	S2a	BV28	SBS2
Fly Ash Silo Bin Vent Filter	S2b	BV29	FAS2

Facility Name: PyraMax Ceramics, LLC **Date of Application:** July 2011

Form 3.00 – AIR POLLUTION CONTROL DEVICES - PART A: GENERAL EQUIPMENT INFORMATION

APCD Unit ID	Emission Unit ID	APCD Type (Baghouse, ESP, Scrubber etc)	Date Installed	Make & Model Number (Attach Mfg. Specifications & Literature)	Unit Modified from Mfg Specifications?	Gas Temp. °F		Inlet Gas Flow Rate (acfm)
						Inlet	Outlet	
BV10,20	FB1,2	Bin Vent Filter	June 2012	TBD	N/A	68	68	125
BHD1,2	KDR1,2	Baghouse	June 2012	TBD	N/A	68	68	722
BVS1	ADS1	Bin Vent Filter	June 2012	TBD	N/A	68	68	500
BHP1,2	PEL1,2 CP1,2 CSB1,2 EGP1,2	Baghouse	June 2012	TBD	N/A	200	200	103,653
BHG1,2	GS11,21 GS12,22 OE1,2 RBC1,2 KFE1,2	Baghouse	June 2012	TBD	N/A	68	68	6,807
BHM1,2	CM1,2 CYC1,2 SC1,2	Baghouse	June 2012	TBD	N/A	68	68	400

Facility Name: PyraMax Ceramics, LLC **Date of Application:** July 2011

Form 3.00 – AIR POLLUTION CONTROL DEVICES – PART B: EMISSION INFORMATION

APCD Unit ID	Pollutants Controlled	Percent Control Efficiency		Inlet Stream To APCD		Exit Stream From APCD		Pressure Drop Across Unit (Inches of water)
		Design	Actual	lb/hr	Method of Determination	lb/hr	Method of Determination	
BV10,20	PM, PM10	99%	99%	0.231	Eng. estimate	$2.31x10^{-3}$	Eng. estimate	2-10
	PM2.5	99%	99%	0.122	Eng. estimate	$1.22x10^{-3}$	Eng. estimate	
BHD1,2	PM, PM10	99%	99%	3.21	Eng. estimate	$3.21x10^{-2}$	Eng. estimate	2-10
	PM2.5	99%	99%	1.69	Eng. estimate	$1.69x10^{-2}$	Eng. estimate	
BVS1	PM, PM10	99%	99%	2.14	Eng. estimate	$2.14x10^{-2}$	Eng. estimate	2-10
	PM2.5	99%	99%	1.13	Eng. estimate	$1.13x10^{-2}$	Eng. estimate	
BHP1,2	PM, PM10	99%	99%	770	Eng. estimate	7.7	Eng. estimate	2-10
	PM2.5	99%	99%	426	Eng. estimate	4.26	Eng. estimate	
BHG1,2	PM, PM10	99%	99%	32.1	Eng. estimate	0.321	Eng. estimate	2-10
	PM2.5	99%	99%	16.9	Eng. estimate	0.169	Eng. estimate	
BHM1,2	PM, PM10	99%	99%	0.0771	Eng. estimate	$7.71x10^{-4}$	Eng. estimate	2-10
	PM2.5	99%	99%	0.0406	Eng. estimate	$4.06x10^{-4}$	Eng. estimate	
BV11,21	PM, PM10	99%	99%	1.04	Eng. estimate	$1.04x10^{-2}$	Eng. estimate	2-10
	PM2.5	99%	99%	0.546	Eng. estimate	$5.46x10^{-3}$	Eng. estimate	

Facility Name: PyraMax Ceramics, LLC **Date of Application:** July 2011

Form 3.00 – AIR POLLUTION CONTROL DEVICES - PART A: GENERAL EQUIPMENT INFORMATION

APCD Unit ID	Emission Unit ID	APCD Type (Baghouse, ESP, Scrubber etc)	Date Installed	Make & Model Number (Attach Mfg. Specifications & Literature)	Unit Modified from Mfg Specifications?	Gas Temp. °F		Inlet Gas Flow Rate (acfm)
						Inlet	Outlet	
BV11,21	KRF1,2	Bin Vent Filter	June 2012	TBD	N/A	68	68	220
BHK1,2	KLN1,2 KC1,2 GRZ1,2	Baghouse	June 2012	TBD	N/A	258	258	54,777
BHF1,2	CE1,2 FS11,21 FS12,22 FS13,23 FS14,24 RB11,21 RB12,22 RE1,2	Baghouse	June 2012	TBD	N/A	68	68	7,866
BV12,22	S11,21	Bin Vent Filter	June 2012	TBD	N/A	68	68	220
BV13,23	S12,22	Bin Vent Filter	June 2012	TBD	N/A	68	68	220
BV14,24	S13,23	Bin Vent Filter	June 2012	TBD	N/A	68	68	220
BV15,25	S14,24	Bin Vent Filter	June 2012	TBD	N/A	68	68	220
BV16,26	S15,25	Bin Vent Filter	June 2012	TBD	N/A	68	68	220

Facility Name: PyraMax Ceramics, LLC **Date of Application:** July 2011

Form 3.00 – AIR POLLUTION CONTROL DEVICES – PART B: EMISSION INFORMATION

APCD Unit ID	Pollutants Controlled	Percent Control Efficiency		Inlet Stream To APCD		Exit Stream From APCD		Pressure Drop Across Unit (Inches of water)
		Design	Actual	lb/hr	Method of Determination	lb/hr	Method of Determination	
BHK1,2	PM, PM10	99%	99%	853	Eng. estimate	8.53	Eng. estimate	2-10
	PM2.5	99%	99%	698	Eng. estimate	6.98	Eng. estimate	
	SO2	90%	90%	116	Eng. estimate	11.6	Eng. estimate	
	NOX	80%	80%	181.5	Eng. estimate	36.3	Eng. estimate	
BHF1,2	PM, PM10	99%	99%	37.1	Eng. estimate	0.371	Eng. estimate	2-10
	PM2.5	99%	99%	19.5	Eng. estimate	0.195	Eng. estimate	
BV12,22	PM, PM10	99%	99%	1.03	Eng. estimate	1.03×10^{-2}	Eng. estimate	2-10
	PM2.5	99%	99%	0.541	Eng. estimate	5.41×10^{-3}	Eng. estimate	
BV13,23	PM, PM10	99%	99%	1.03	Eng. estimate	1.03×10^{-2}	Eng. estimate	2-10
	PM2.5	99%	99%	0.541	Eng. estimate	5.41×10^{-3}	Eng. estimate	
BV14,24	PM, PM10	99%	99%	1.03	Eng. estimate	1.03×10^{-2}	Eng. estimate	2-10
	PM2.5	99%	99%	0.541	Eng. estimate	5.41×10^{-3}	Eng. estimate	
BV15,25	PM, PM10	99%	99%	1.03	Eng. estimate	1.03×10^{-2}	Eng. estimate	2-10
	PM2.5	99%	99%	0.541	Eng. estimate	5.41×10^{-3}	Eng. estimate	
BV16,26	PM, PM10	99%	99%	1.03	Eng. estimate	1.03×10^{-2}	Eng. estimate	2-10
	PM2.5	99%	99%	0.541	Eng. estimate	5.41×10^{-3}	Eng. estimate	

Facility Name: PyraMax Ceramics, LLC **Date of Application:** July 2011

Form 3.00 – AIR POLLUTION CONTROL DEVICES - PART A: GENERAL EQUIPMENT INFORMATION

APCD Unit ID	Emission Unit ID	APCD Type (Baghouse, ESP, Scrubber etc)	Date Installed	Make & Model Number (Attach Mfg. Specifications & Literature)	Unit Modified from Mfg Specifications?	Gas Temp. °F		Inlet Gas Flow Rate (acfm)
						Inlet	Outlet	
BV17,27	WB1,2	Bin Vent Filter	June 2012	TBD	N/A	68	68	39
BHL1,2	BC1,2	Baghouse	June 2012	TBD	N/A	68	68	14,633
	LE1,2							
	LS1,2							
BV18,28	SBS1,2	Bin Vent Filter	June 2012	TBD	N/A	68	68	500
BV19,29	FAS1,2	Bin Vent Filter	June 2012	TBD	N/A	68	68	2,000

Facility Name: PyraMax Ceramics, LLC **Date of Application:** July 2011

Form 3.00 – AIR POLLUTION CONTROL DEVICES – PART B: EMISSION INFORMATION

APCD Unit ID	Pollutants Controlled	Percent Control Efficiency		Inlet Stream To APCD		Exit Stream From APCD		Pressure Drop Across Unit (Inches of water)
		Design	Actual	lb/hr	Method of Determination	lb/hr	Method of Determination	
BV17,27	PM, PM10	99%	99%	0.171	Eng. estimate	1.71×10^{-3}	Eng. estimate	2-10
	PM2.5	99%	99%	0.0902	Eng. estimate	9.02×10^{-4}	Eng. estimate	
BHL1,2	PM, PM10	99%	99%	69	Eng. estimate	0.69	Eng. estimate	2-10
	PM2.5	99%	99%	36.3	Eng. estimate	0.363	Eng. estimate	
BV18,28	PM, PM10	99%	99%	2.14	Eng. estimate	2.14×10^{-2}	Eng. estimate	2-10
	PM2.5	99%	99%	1.13	Eng. estimate	1.13×10^{-2}	Eng. estimate	
BV19,29	PM, PM10	99%	99%	8.57	Eng. estimate	8.57×10^{-2}	Eng. estimate	2-10
	PM2.5	99%	99%	4.51	Eng. estimate	4.51×10^{-2}	Eng. estimate	

Facility Name: PyraMax Ceramics LLC **Date of Application:** July 2011

FORM 3.02 – BAGHOUSES & OTHER FILTER COLLECTORS

APCD ID	Filter Surface Area (ft^2)	No. of Bags	Inlet Gas Dew Point Temp. (°F)	Inlet Gas Temp. (°F)	Bag or Filter Material	Pressure Drop (inches of water)	Cleaning Method	Gas Cooling Method	Leak Detection System Type
BV10, 20	TBD	TBD	TBD	68	TBD	2-10	Pulse jet	TBD	TBD
BHD1,2	TBD	TBD	TBD	68	TBD	2-10	Pulse or Shaker	TBD	TBD
BVS1	TBD	TBD	TBD	68	TBD	2-10	Pulse jet	TBD	TBD
BHP1,2	TBD	TBD	TBD	200	TBD	2-10	Pulse or Shaker	TBD	TBD
BHG1,2	TBD	TBD	TBD	68	TBD	2-10	Pulse or Shaker	TBD	TBD
BHM1,2	TBD	TBD	TBD	68	TBD	2-10	Pulse or Shaker	TBD	TBD
BV11, 21	TBD	TBD	TBD	68	TBD	2-10	Pulse jet	TBD	TBD
BHK 1,2**	TBD	TBD	TBD	258	TBD	2-10	Pulse or Shaker	TBD	TBD
**The catalytic baghouse is a combination device that controls PM, SO2, and NOx. It is listed under baghouses for simplicity.									
BHF1,2	TBD	TBD	TBD	68	TBD	2-10	Pulse or Shaker	TBD	TBD
BV12, 22	TBD	TBD	TBD	68	TBD	2-10	Pulse jet	TBD	TBD
BV13, 23	TBD	TBD	TBD	68	TBD	2-10	Pulse jet	TBD	TBD
BV14, 24	TBD	TBD	TBD	68	TBD	2-10	Pulse jet	TBD	TBD
BV15, 25	TBD	TBD	TBD	68	TBD	2-10	Pulse jet	TBD	TBD
BV16, 26	TBD	TBD	TBD	68	TBD	2-10	Pulse jet	TBD	TBD

Attach a physical description, dimensions and drawings for each baghouse and any additional information available such as particle size, maintenance schedules, monitoring procedures and breakdown/by-pass procedures. Explain how collected material is disposed of or utilized. Include the attachment in the list on Form 1.00 *General Information*, Item 16

Facility Name: PyraMax Ceramics LLC **Date of Application:** July 2011

FORM 3.02 – BAGHOUSES & OTHER FILTER COLLECTORS

APCD ID	**Filter Surface Area** (ft^2)	**No. of Bags**	**Inlet Gas Dew Point Temp.** (°F)	**Inlet Gas Temp.** (°F)	**Bag or Filter Material**	**Pressure Drop** (inches of water)	**Cleaning Method**	**Gas Cooling Method**	**Leak Detection System Type**
BV17, 27	TBD	TBD	TBD	68	TBD	2-10	Pulse jet	TBD	TBD
BHL1,2	TBD	TBD	TBD	68	TBD	2-10	Pulse or Shaker	TBD	TBD
BV18, 28	TBD	TBD	TBD	68	TBD	2-10	Pulse jet	TBD	TBD
BV19, 29	TBD	TBD	TBD	68	TBD	2-10	Pulse jet	TBD	TBD

Attach a physical description, dimensions and drawings for each baghouse and any additional information available such as particle size, maintenance schedules, monitoring procedures and breakdown/by-pass procedures. Explain how collected material is disposed of or utilized. Include the attachment in the list on Form 1.00 *General Information*, Item 16

Facility Name: Pyramax Ceramics LLC **Date of Application:** July 2011

FORM 4.00 – EMISSION INFORMATION

Emission Unit ID	Air Pollution Control Device ID	Stack ID	Pollutant Emitted	Emission Rates				
				Hourly Actual Emissions (lb/hr)	Hourly Potential Emissions (lb/hr)	Actual Annual Emission (tpy)	Potential Annual Emission (tpy)	Method of Determination
FB1,2	BV10,20	SV10,20	PM, PM10	2.31x10^{-3}	2.31x10^{-3}	0.01	0.01	Eng estimate
FB1,2	BV10,20	SV10,20	PM2.5	1.22x10^{-3}	1.22x10^{-3}	5.34x10^{-3}	5.34x10^{-3}	Eng estimate
KDR1,2	BHD1,2	SBD1,2	PM, PM10	0.03	0.03	0.14	0.14	Eng estimate
KDR1,2	BHD1,2	SBD1,2	PM2.5	0.02	0.02	0.07	0.07	Eng estimate
ADS1	BVS1	SVS1	PM, PM10	0.02	0.02	0.09	0.09	Eng estimate
ADS1	BVS1	SVS1	PM2.5	0.01	0.01	0.05	0.05	
PEL1,2	BHP1,2	SBP1,2	PM, PM10	7.70	7.70	33.72	33.72	Eng estimate
CP1,2								
CSB1,2								
EGP1,2								
PEL1,2	BHP1,2	SBP1,2	PM2.5	4.26	4.26	18.64	18.64	Eng estimate
CP1,2								
CSB1,2								
EGP1,2								

Facility Name: Pyramax Ceramics LLC **Date of Application:** July 2011

FORM 4.00 – EMISSION INFORMATION

Emission Unit ID	Air Pollution Control Device ID	Stack ID	Pollutant Emitted	Emission Rates				
				Hourly Actual Emissions (lb/hr)	Hourly Potential Emissions (lb/hr)	Actual Annual Emission (tpy)	Potential Annual Emission (tpy)	Method of Determination
PEL1,2 CP1,2 CSB1,2 EGP1,2	BHP1,2	SBP1,2	SO2	0.05	0.05	0.20	0.20	AP-42
PEL1,2 CP1,2 CSB1,2 EGP1,2	BHP1,2	SBP1,2	NOx	2.25	2.25	9.86	9.86	Manufacturer emission factor
PEL1,2 CP1,2 CSB1,2 EGP1,2	BHP1,2	SBP1,2	CO	13.73	13.73	60.12	60.12	Manufacturer emission factor

Facility Name: Pyramax Ceramics LLC **Date of Application:** July 2011

FORM 4.00 – EMISSION INFORMATION

Emission Unit ID	Air Pollution Control Device ID	Stack ID	Pollutant Emitted	Emission Rates				
				Hourly Actual Emissions (lb/hr)	Hourly Potential Emissions (lb/hr)	Actual Annual Emission (tpy)	Potential Annual Emission (tpy)	Method of Determination
PEL1,2	BHP1,2	SBP1,2	VOC	11.78	11.78	51.59	51.59	AP-42
CP1,2								
CSB1,2								
EGP1,2								
PEL1,2	BHP1,2	SBP1,2	CO2e	10,148	10,148	44,446	44,446	40 CFR 98
CP1,2								
CSB1,2								
EGP1,2								
OSB1,2	N/A	N/A	PM, PM10	7.71x10^{-4}	7.71x10^{-4}	3.38x10^{-3}	3.38x10^{-3}	Eng estimate
OSB1,2	N/A	N/A	PM2.5	4.06x10^{-4}	4.06x10^{-4}	1.78x10^{-3}	1.78x10^{-3}	Eng estimate

Facility Name: PyraMax Ceramics LLC **Date of Application:** July 2011

FORM 4.00 – EMISSION INFORMATION

Emission Unit ID	Air Pollution Control Device ID	Stack ID	Pollutant Emitted	Emission Rates				
				Hourly Actual Emissions (lb/hr)	Hourly Potential Emissions (lb/hr)	Actual Annual Emission (tpy)	Potential Annual Emission (tpy)	Method of Determination
USB1,2	N/A	N/A	PM, PM10	$1.59\text{x}10^{-3}$	$1.59\text{x}10^{-3}$	$6.95\text{x}10^{-3}$	$6.95\text{x}10^{-3}$	Eng estimate
USB1,2	N/A	N/A	PM2.5	$8.35\text{x}10^{-4}$	$8.35\text{x}10^{-4}$	$3.66\text{x}10^{-3}$	$3.66\text{x}10^{-3}$	Eng estimate
GS11, 21 GS12, 22 OE1,2 RBC1,2 KFE1,2	BHG1,2	SBG1,2	PM, PM10	0.32	0.32	1.41	1.41	Eng estimate
GS11, 21 GS12, 22 OE1,2 RBC1,2 KFE1,2	BHG1,2,3,4	SBG1,2	PM2.5	0.17	0.17	0.74	0.74	Eng estimate

Facility Name: PyraMax Ceramics LLC **Date of Application:** July 2011

FORM 4.00 – EMISSION INFORMATION

Emission Unit ID	Air Pollution Control Device ID	Stack ID	Pollutant Emitted	Emission Rates				
				Hourly Actual Emissions (lb/hr)	Hourly Potential Emissions (lb/hr)	Actual Annual Emission (tpy)	Potential Annual Emission (tpy)	Method of Determination
CM1,2	BHM1,2	SBM1,2	PM, PM10	$7.71\text{x}10^{-4}$	$7.71\text{x}10^{-4}$	$3.38\text{x}10^{-3}$	$3.38\text{x}10^{-3}$	Eng estimate
CYC1,2								
SC1,2								
CM1,2	BHM1,2	SBM1,2	PM2.5	$4.06\text{x}10^{-4}$	$4.06\text{x}10^{-4}$	$1.78\text{x}10^{-3}$	$1.78\text{x}10^{-3}$	Eng estimate
CYC1,2								
SC1,2								
KFB1,2	N/A	N/A	PM, PM10	$7.71\text{x}10^{-4}$	$7.71\text{x}10^{-4}$	$3.38\text{x}10^{-3}$	$3.38\text{x}10^{-3}$	Eng estimate
KFB1,2	N/A	N/A	PM2.5	$4.06\text{x}10^{-4}$	$4.06\text{x}10^{-4}$	$1.78\text{x}10^{-3}$	$1.78\text{x}10^{-3}$	Eng estimate
KRF1,2	BV11, 21	SV11, 21	PM, PM10	0.01	0.01	0.05	0.05	Eng estimate
KRF1,2	BV11, 21	SV11, 21	PM2.5	$5.46\text{x}10^{-3}$	$5.46\text{x}10^{-3}$	0.02	0.02	Eng estimate
KRW1,2	N/A	N/A	PM, PM10	0.01	0.01	0.05	0.05	Eng estimate
KRW1,2	N/A	N/A	PM2.5	$5.46\text{x}10^{-3}$	$5.46\text{x}10^{-3}$	0.02	0.02	Eng estimate
KLN1,2	BHK1,2	SBK1,2	PM, PM10	8.53	8.53	37.37	37.37	Eng estimate
KC1,2								
GRZ1,2								
KLN1,2	BHK1,2	SBk1,2	PM2.5	6.98	6.98	30.58	30.58	Eng estimate
KC1,2								
GRZ1,2								

Facility Name: PyraMax Ceramics LLC **Date of Application:** July 2011

FORM 4.00 – EMISSION INFORMATION

Emission Unit ID	Air Pollution Control Device ID	Stack ID	Pollutant Emitted	Emission Rates				
				Hourly Actual Emissions (lb/hr)	Hourly Potential Emissions (lb/hr)	Actual Annual Emission (tpy)	Potential Annual Emission (tpy)	Method of Determination
KLN1,2	BHK1,2	SBK1,2	SO2	11.64	11.64	51.00	51.00	Eng estimate
KC1,2								
GRZ1,2								
KLN1,2	BHK1,2	SBK1,2	NOx	36.30	36.30	158.99	158.99	Eng estimate
KC1,2								
GRZ1,2								
KLN1,2	BHK1,2	SBK1,2	CO	55.50	55.50	243.08	243.08	AP-42
KC1,2								
GRZ1,2								
KLN1,2	BHK1,2	SBK1,2	VOC	0.54	0.54	2.36	2.36	AP-42
KC1,2								
GRZ1,2								
KLN1,2	BHK1,2	SBK1,2	CO2e	7,638	7,638	33,454	33,454	40 CFR 98
KC1,2								
GRZ1,2								
QC11, 21	N/A	N/A	PM, PM10	$1.71x10^{-4}$	$1.71x10^{-4}$	$7.51x10^{-4}$	$7.51x10^{-4}$	Eng estimate
QC11, 21	N/A	N/A	PM2.5	$9.02x10^{-5}$	$9.02x10^{-5}$	$3.95x10^{-4}$	$3.95x10^{-4}$	Eng estimate
QC12, 22	N/A	N/A	PM, PM10	$1.71x10^{-4}$	$1.71x10^{-4}$	$7.51x10^{-4}$	$7.51x10^{-4}$	Eng estimate
QC12, 22	N/A	N/A	PM2.5	$9.02x10^{-5}$	$9.02x10^{-5}$	$3.95x10^{-4}$	$3.95x10^{-4}$	Eng estimate

Facility Name: PyraMax Ceramics LLC **Date of Application:** July 2011

FORM 4.00 – EMISSION INFORMATION

Emission Unit ID	Air Pollution Control Device ID	Stack ID	Pollutant Emitted	Emission Rates				
				Hourly Actual Emissions (lb/hr)	Hourly Potential Emissions (lb/hr)	Actual Annual Emission (tpy)	Potential Annual Emission (tpy)	Method of Determination
QC13, 23	N/A	N/A	PM, PM10	$1.71x10^{-4}$	$1.71x10^{-4}$	$7.51x10^{-4}$	$7.51x10^{-4}$	Eng estimate
QC13, 23	N/A	N/A	PM2.5	$9.02x10^{-5}$	$9.02x10^{-5}$	$3.95x10^{-4}$	$3.95x10^{-4}$	Eng estimate
QC14, 24	N/A	N/A	PM, PM10	$1.71x10^{-4}$	$1.71x10^{-4}$	$7.51x10^{-4}$	$7.51x10^{-4}$	Eng estimate
QC14, 24	N/A	N/A	PM2.5	$9.02x10^{-5}$	$9.02x10^{-5}$	$3.95x10^{-4}$	$3.95x10^{-4}$	Eng estimate
RWB1,2	N/A	N/A	PM, PM10	$1.71x10^{-4}$	$1.71x10^{-4}$	$7.51x10^{-4}$	$7.51x10^{-4}$	Eng estimate
RWB1,2	N/A	N/A	PM2.5	$9.02x10^{-5}$	$9.02x10^{-5}$	$3.95x10^{-4}$	$3.95x10^{-4}$	Eng estimate
CE1,2	BHF1,2	SBF1,2	PM, PM10	0.37	0.37	1.62	1.62	Eng estimate
FS11, 21								
FS12, 22								
FS13, 23								
FS14, 24								
RB11, 21								
RB12, 22								
RE1,2								

Facility Name: PyraMax Ceramics LLC **Date of Application:** July 2011

FORM 4.00 – EMISSION INFORMATION

Emission Unit ID	Air Pollution Control Device ID	Stack ID	Pollutant Emitted	Emission Rates				
				Hourly Actual Emissions (lb/hr)	Hourly Potential Emissions (lb/hr)	Actual Annual Emission (tpy)	Potential Annual Emission (tpy)	Method of Determination
CE1,2,3	BHF1,2	SBF1,2	PM2.5	0.20	0.20	0.85	0.85	Eng estimate
FS11, 21								
FS12, 22								
FS13, 23								
FS14, 24								
RB11, 21								
RB12, 22								
RE1,2								
S11,21	BV12,22	SV12,22	PM, PM10	0.01	0.01	0.05	0.05	Eng estimate
S11,21	BV12,22	SV12,22	PM2.5	$5.41\text{x}10^{-3}$	$5.41\text{x}10^{-3}$	0.02	0.02	Eng estimate
S12,22	BV13,23	SV13,23	PM, PM10	0.01	0.01	0.05	0.05	Eng estimate
S12,22	BV13,23	SV13,23	PM2.5	$5.41\text{x}10^{-3}$	$5.41\text{x}10^{-3}$	0.02	0.02	Eng estimate
S13,23	BV14,24	SV14,24	PM, PM10	0.01	0.01	0.05	0.05	Eng estimate
S13,23	BV14,24	SV14,24	PM2.5	$5.41\text{x}10^{-3}$	$5.41\text{x}10^{-3}$	0.02	0.02	Eng estimate
S14,24	BV15,25	SV15,25	PM, PM10	0.01	0.01	0.05	0.05	Eng estimate
S14,24	BV15,25	SV15,25	PM2.5	$5.41\text{x}10^{-3}$	$5.41\text{x}10^{-3}$	0.02	0.02	Eng estimate
S15,25	BV16,26	SV16,26	PM, PM10	0.01	0.01	0.05	0.05	Eng estimate
S15,25	BV16,26	SV16,26	PM2.5	$5.41\text{x}10^{-3}$	$5.41\text{x}10^{-3}$	0.02	0.02	Eng estimate
WB1,2	BV17,27	SV17,27	PM, PM10	$1.71\text{x}10^{-3}$	$1.71\text{x}10^{-3}$	$7.51\text{x}10^{-3}$	$7.51\text{x}10^{-3}$	Eng estimate

Facility Name: PyraMax Ceramics LLC **Date of Application:** July 2011

FORM 4.00 – EMISSION INFORMATION

Emission Unit ID	Air Pollution Control Device ID	Stack ID	Pollutant Emitted	Emission Rates				
				Hourly Actual Emissions (lb/hr)	Hourly Potential Emissions (lb/hr)	Actual Annual Emission (tpy)	Potential Annual Emission (tpy)	Method of Determination
WB1,2	BV17,27	SV17, 27	PM2.5	9.02x10^{-4}	9.02x10^{-4}	3.95x10^{-3}	3.95x10^{-3}	Eng estimate
BC1,2	BHL1,2	SBL1,2	PM, PM10	0.69	0.69	3.02	3.02	Eng estimate
LE1,2								
LS1,2								
BC1,2	BHL1,2	SBL1,2	PM2.5	0.36	0.36	1.59	1.59	Eng estimate
LE1,2								
LS1,2								
SBS1,2	BV18,28	SV18, 28	PM, PM10	0.02	0.02	0.09	0.09	Eng estimate
SBS1,2	BV18,28	SV18, 28	PM2.5	0.01	0.01	0.05	0.05	Eng estimate
FAS1,2	BV19,29	SV19, 29	PM, PM10	0.09	0.09	0.38	0.38	Eng estimate
FAS1,2	BV19,29	SV19, 29	PM2.5	0.05	0.05	0.20	0.20	Eng estimate
B1,2	N/A	STB1,2	PM, PM10, PM2.5	0.07	0.07	0.33	0.33	AP-42
B1,2	N/A	STB1,2	SO2	5.88x10^{-3}	5.88x10^{-3}	0.03	0.03	AP-42
B1,2	N/A	STB1,2	NOx	1.39	1.39	6.10	6.10	AP-42
B1,2	N/A	STB1,2	CO	0.11	0.11	0.47	0.47	AP-42
B1,2	N/A	STB1,2	VOC	0.82	0.82	3.61	3.61	AP-42
B1,2	N/A	STB1,2	CO2e	1,326	1,326	5,808	5,808	40 CFR 98
G1,2	N/A	N/A	PM, PM10, PM2.5	0.44	0.44	0.02	0.02	NSPS Subpart III
G1,2	N/A	N/A	SO2	2.75	2.75	0.14	0.14	AP-42

Facility Name: PyraMax Ceramics LLC **Date of Application:** July 2011

FORM 4.00 – EMISSION INFORMATION

Emission Unit ID	Air Pollution Control Device ID	Stack ID	Pollutant Emitted	Emission Rates				
				Hourly Actual Emissions (lb/hr)	Hourly Potential Emissions (lb/hr)	Actual Annual Emission (tpy)	Potential Annual Emission (tpy)	Method of Determination
G1,2	N/A	N/A	NOx	8.82	8.82	0.44	0.44	NSPS Subpart III
G1,2	N/A	N/A	CO	7.72	7.72	0.39	0.39	NSPS Subpart III
G1,2	N/A	N/A	VOC	8.82	8.82	0.44	0.44	NSPS Subpart III
G1,2	N/A	N/A	CO2e	1,535	1,535	76.73	76.73	40 CFR 98
DST1,2	N/A	N/A	VOC	2.27×10^{-4}	2.27×10^{-4}	9.95×10^{-4}	9.95×10^{-4}	Eng estimate
DST3	N/A	N/A	VOC	6.70×10^{-4}	6.70×10^{-4}	2.94×10^{-3}	2.94×10^{-3}	Eng estimate
DST4	N/A	N/A	VOC	8.90×10^{-5}	8.90×10^{-5}	3.90×10^{-4}	3.90×10^{-4}	Eng estimate

Facility Name: PyraMax Ceramics LLC **Date of Application:** July 2011

FORM 5.00 MONITORING INFORMATION

Emission Unit ID/ APCD ID	Emission Unit/APCD Name	Monitored Parameter		Monitoring Frequency
		Parameter	Units	
KLN1,2/ BHK1,2	Kiln/Catalytic baghouse	Opacity	%	Continuous
PEL1,2/ BHP1,2	Pelletizer/Pelletizer baghouse	Opacity	%	Continuous
PEL1,2/ BHP1,2	Pelletizer/ Pelletizer baghouse	Methanol/VOC	tons	Monthly production records

Comments:

Facility Name: PyraMax Ceramics LLC **Date of Application:** July 2011

FORM 7.00 – AIR MODELING INFORMATION: Stack Data

Stack ID	Emission Unit ID(s)	Stack Information			Dimensions of largest Structure Near Stack		Exit Gas Conditions at Maximum Emission Rate			
		Height Above Grade (ft)	**Inside Diameter** (ft)	**Exhaust Direction**	**Height** (ft)	**Longest Side** (ft)	**Velocity** (ft/sec)	**Temperature** (°F)	**Flow Rate** (acfm)	
									Average	**Maximum**
SV10, 20	FB1,2	150	0.33	Vertical	***	***	23.87	68	125	125
SBD1,2	BHD1,2	150	0.67	Vertical	***	***	34.47	68	722	722
SBP1,2	BHP1,2	250	6.00	Vertical	***	***	61.10	200	103,653	103,653
SBG1,2	BHG1,2	160	1.67	Vertical	***	***	52.00	68	6,807	6,807
SBM1, 2	BHM1,2	150	1.67	Vertical	***	***	3.06	68	400	400
SV11, 21	KRF1,2	150	0.33	Vertical	***	***	42.02	68	220	220
SBK1,2	BHK1,2	300	6.17	Vertical	***	***	30.57	258	54,777	54,777
SBF1,2	BHF1,2	145	1.83	Vertical	***	***	49.66	68	7,866	7,866
SV12, 22	S11, 21	100	0.33	Vertical	***	***	42.02	68	220	220

NOTE: If emissions are not vented through a stack, describe point of discharge below and, if necessary, include an attachment. List the attachment in Form 1.00 *General Information*, Item 16.

*** - Site structure dimension data provided within BPIP analysis included with modeling files as part of this application.

Facility Name: PyraMax Ceramics LLC **Date of Application:** July 2011

FORM 7.00 AIR MODELING INFORMATION: Chemicals Data

Chemical	Potential Emission Rate (lb/hr)	Toxicity	Reference	MSDS Attached
See Air Toxics Analysis				☐
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Facility Name: PyraMax Ceramics LLC **Date of Application:** July 2011

FORM 7.00 – AIR MODELING INFORMATION: Stack Data

Stack ID	**Emission Unit ID(s)**	**Stack Information**			**Dimensions of largest Structure Near Stack**		**Exit Gas Conditions at Maximum Emission Rate**			
		Height Above Grade (ft)	**Inside Diameter** (ft)	**Exhaust Direction**	**Height** (ft)	**Longest Side** (ft)	**Velocity** (ft/sec)	**Temperature** (°F)	**Flow Rate** (acfm)	
									Average	**Maximum**
SV13, 23	S12, 22	100	0.33	Vertical	***	***	42.02	68	220	220
SV14, 24	S13, 23	100	0.33	Vertical	***	***	42.02	68	220	220
SV15, 25	S14, 24	100	0.33	Vertical	***	***	42.02	68	220	220
SV16, 26	S15, 25	100	0.33	Vertical	***	***	42.02	68	220	220
SV17, 27	WB1,2	55	0.33	Vertical	***	***	7.45	68	39	39
SBL1,2	BHL1,2	100	2.50	Vertical	***	***	49.68	68	14,633	14,633
SV18, 28	SBS1,2	55	1.64	Vertical	***	***	3.94	68	500	500
SV19, 29	FAS1,2	55	1.64	Vertical	***	***	15.78	68	2,000	2,000
STB1,2	B1,2	60	2.27	Vertical	***	***	44.96	380	10,882	10,882
SVS1	ADS1	55	1.64	TBD	***	***	3.94	68	500	500

NOTE: If emissions are not vented through a stack, describe point of discharge below and, if necessary, include an attachment. List the attachment in Form 1.00 *General Information*, Item 16.

*** - Site structure dimension data provided within BPIP analysis included with modeling files as part of this application.

APPENDIX G – MSDS/RAW MATERIAL INFORMATION

MSDS Safety Information

TOP

FSC: 6810 **NIIN:** 00-584-3793 **MSDS Date:** 01/29/1990 **MSDS Num:** BFGPY

Submitter: D DG **Tech Review:** 04/10/1999 **Status CD:** C

Product ID: **AQUA AMMONIA 26 DEG BAUME** **MFN:** 01

Article: N **Kit Part:** N

Responsible Party **Cage:** 5A188

Name: ASHLAND CHEMICAL CO.

Box: 2219

City: COLUMBUS **State:** OH **Zip:** 43216

Country: US

Info Phone Number: 614-889-3333

Emergency Phone Number: 606-324-1133

Preparer's Name: N/P

Proprietary Ind: N **Review Ind:** Y

Published: Y **Special Project CD:** N

Contractor Summary

TOP

Cage:5A188 **Name:****ASHLAND CHEMICAL CO**

Address:5200 PAUL BLAZEL MEMORIAL PARKWAY

City:DUBLIN **State:**OH **Zip:**43017

Country:US **Phone:**614-889-4505

Item Description Information

TOP

Item Manager: S9G

Item Name: AMMONIUM HYDROXIDE,TECHNICAL

Specification Number: O-A-451F **Type/Grade/Class:** TY I

Unit of Issue: PT **Quantitative Expression:** NK

UI Container Qty: 16 FL OZ **Type of Container:** GLASS BOTTLE

Ingredients

TOP

Cas: 1336-21-6 **Code:** M **RTECS #:** BQ9625000 **Code:** M

Name: **AMMONIUM HYDROXIDE (SARA III)**

% Text: 61.0 **Environmental Wt:**

Other REC Limits: NONE SPECIFIED

OSHA PEL: NOT ESTABLISHED **Code:** M **OSHA STEL:** **Code:**

ACGIH TLV: NOT ESTABLISHED **Code:** M **ACGIH STEL:** N/P **Code:**

EPA Rpt Qty: 1000 LBS **DOT Rpt Qty:** 1000 LBS

Ozone Depleting Chemical: N

Cas: 7732-18-5 **Code:** M **RTECS #:** ZC0110000 **Code:** M

Name: **WATER**

% Text: 40 **Environmental Wt:**

Other REC Limits: NONE SPECIFIED

OSHA PEL: NOT ESTABLISHED **Code:** M **OSHA STEL:** **Code:**

ACGIH TLV: NOT ESTABLISHED **Code:** M **ACGIH STEL:** N/P **Code:**

EPA Rpt Qty: **DOT Rpt Qty:**

Ozone Depleting Chemical: N

Health Hazards Data

TOP

LD50 LC50 MixtureN/P

Route Of Entry Inds - Inhalation:YES **Skin:**YES **Ingestion:**YES

Carcinogenicity Inds - NTP:NO **IARC:**NO **OSHA:**NO

Health Hazards Acute And Chronic

ACUTE: HARMFUL IF SWALLOWED, INHALED, OR ABSORBED THROUGH SKIN. MATERIAL IS EXTREMELY DESTRUCTIVE TO TISSUE OF THE MUCOUS MEMBRANES AND UPPER RESPIRATORY TRACT, EYES AND SKIN. INHALATION MAY BE FATAL AS A RESULT OF SPASM, INFLAMMATION AND E DEMA OF THE LAYNX AND BRONCHI, CHEMICAL PNEUMONITIS AND PULMONARY EDEMA.

Explanation Of Carcinogenicity

N/P

Signs And Symptions Of Overexposure

INHALATION:CORROSIVE! VAPORS CAN CAUSE COUGHING,CHOKING,&

INFLAMATION OF THE RESPIRATORY TRACT. INGESTION:CORROSIVE! CAN CAUSE BURNS TO MOUTH & GI TRACT. MAY ERODE TEETH.LARGE QUANTITY MAY CAUSE DEATH. EYE/SKIN:CORROSIVE! CAN CAUSE SEVERE B URNS,DAMAGE,DEP ULCERS & DISCOLOR SKIN. SPLASH MAY CAUSE SEVERE BURNS TO EYES.

Medical Cond Aggravated By Exposure

PERSONS WITH A HISTORY OF AILMENTS OR WITH A PRE-EXISTING DISEASE INVOLVING THE EYES, SKIN, OR RESPIRATORY TRACT MAY BE AT INCREASED RISK FROM EXPOSURE.

First Aid

INHALATION:REMOVE TO FRESH AIR. RESUSCITATE IF NOT BREATHING. GET IMMEDIATE MEDICAL ATTENTION. EYES:IMMEDIATELY FLUSH WITH PLENTY OF WATER FOR 15 MINUTES HOLDING EYELIDS OPEN. GET IMMEDIATE MEDICAL ATTENTION. SKIN:REMOVE CONTAMINATED CLOTHI NG. WASH WITHSOAP AND WATER. GET MEDICAL ATTENTION. INGESTION:DO NOT INDUCE VOMITING. GIVE NOTHING BY MOUTH IF UNCONSCIOUS. GET IMMEDIATE MEDICAL ATTENTION.

Spill Release Procedures

SMALL SPILL: ABSORB LIQUID ON PAPER,VERMICULITE,OR OTHER ABSORBENT AND TRANSFER TO HOOD OR A CLOSED CONTAINER. LARG SPILL:WEAR PROTECTIVE GEARS.DIKE AREA OF SPILL TO PREVENT SPREADING.PUMP LIQUID TO SALVAGE TANK. ABSORB REMAINING LIQ UID ON ABSORBENT

Neutralizing Agent

DILUTE ACETIC ACID OR BORIC ACID.

Waste Disposal Methods

MANUFACTURER SPECIFIED IN THE MSDS THAT SMALL QUANTITY OF PRODUCT CAN BE HANDLED IN NORMAL SEWAGE PLANTS. LARGE QUANTITIES CAN BE USED AS FERTILIZER OR DISPOSED OF IN ACCORDANCE WITH FEDERAL, STATE AND LOCAL REGULATIONS.

Handling And Storage Precautions

STORE IN A COOL, DRY AREA. KEEP CONTAINERS TIGHTLY CLOSED WHEN NOT IN USE. PROTECT CONTAINERS FROM PHYSICAL DAMAGE.

Other Precautions

DO NOT TAKE INTERNALLY. DO NOT BREATHE MIST. AVOIDCONTACT WITH EYES AND SKIN. WASH THOROUGHLY AFTER HANDLING.

Fire and Explosion Hazard Information

TOP

Flash Point Method: N/P

Flash Point: **Flash Point Text:** NONE

Autoignition Temp: **Autoignition Temp Text:** N/A

Lower Limits: 16 **Upper Limits:** 25

Extinguishing Media

USE WATER FOG, CARBON DIOXIDE, FOAM, OR DRY CHEMICAL.

Fire Fighting Procedures

FIRE FIGHTERS SHOULD USE NIOSH APPROVED SCBA & FULL PROTECTIVE EQUIPMENT WHEN FIGHTING CHEMICAL FIRE. USE WATER SPRAY TO COOL NEARBY CONTAINERS EXPOSED TO FIRE.

Unusual Fire/Explosion Hazard

FIRE OR EXCESSIVE HEAT MAY CAUSE PRODUCTION OF HAZARDOUS DECOMPOSITION PRODUCTS.

Control Measures

TOP

Respiratory Protection

USE A NIOSH/OSHA APPROVED AIR SUPPLIED RESPIRATOR.

Ventilation

SUFFICIENT MECHANICAL (GENERAL AND/OR LOCAL EXHAUST) VENTILATION TO KEEP EXPOSURES BELOW TLV'S.

Protective Gloves

NATURAL RUBBER OR RUBBER COATED

Eye Protection

SAFETY GOGGLES WITH OPTIONAL FACE SHIELD

Other Protective Equipment

EYE WASH STATION AND SAFETY SHOWER. INDUSTRIAL-TYPE WORK CLOTHING AND APRON AS REQUIRED.

Work Hygienic Practices

OBSERVE GOOD PERSONAL HYGIENE PRACTICES AND RECOMMENDED PROCEDURES. DO NOT WEAR CONTAMINATED CLOTHING OR FOOTWEAR.

Supplemental Safety and Health

NOT APPLICABLE

Physical/Chemical Properties

TOP

HCC: B1 **NRC/State LIC No:**

Net Prop WT For Ammo:

Boiling Point: **B.P. Text:** 85.6F(29.8C

Melt/Freeze Pt: **M.P/F.P Text:** N/A

Decomp Temp:		**Decomp Text:**	UNKNOWN
Vapor Pres:	4.4	**Vapor Density:**	0.6
Volatile Org Content %:		**Spec Gravity:**	0.897
VOC Pounds/Gallon:		**PH:**	13.6
VOC Grams/Liter:		**Viscosity:**	N/P
Evaporation Rate & Reference:	<1 (ETHER=1)		
Solubility in Water:	COMPLETE		
Appearance and Odor:	CLEAR,COLORLESS LIQUID,AMMONIA ODOR.		
Percent Volatiles by Volume:	100	**Corrosion Rate:**	UNKNOWN

Reactivity Data

TOP

Stability Indicator: YES STRONG ACIDS,STRONG ALKALIES,HYPOCHLORITES,BRASS,SILVER,METALLIC MERCURY.

Stability Condition To Avoid: UNK

Materials To Avoid:

Hazardous Decomposition Products: WHEN HEATED, AQUA AMMONIA EMITS TOXIC FUMES OF AMMONIA AND OXIDES OF NITROGEN.

Hazardous Polymerization Indicator: NO

Conditions To Avoid Polymerization: N/A

Toxicological Information

TOP

Toxicological Information: N/P

Ecological Information

TOP

Ecological: N/P

MSDS Transport Information

TOP

Transport Information: N/P

Regulatory Information

TOP

Sara Title III Information: N/P

Federal Regulatory Information: N/P

State Regulatory Information: N/P

Other Information

TOP

Other Information: N/P

HMIS Transportation Information

TOP

Responsible Party Cage:	5A188	**Trans ID NO:**	78076
Product ID:	AQUA AMMONIA 26 DEG BAUME		
MSDS Prepared Date:	01/29/1990	**Review Date:**	06/30/1983
MFN:	1		
Submitter:	D DG	**Status CD:**	C
Article W/O MSDS:	N	**Tech Entry NOS Shipping Nm:**	26.4%
Radioactivity:		**Form:**	
Net Explosive Weight:			
Coast Guard AMMO Code:		**Magnetism:**	N/P
Net Unit Weight:		**AF MMAC Code:**	
DOD Exemption NUM:		**Limited Quantity IND:**	
Multiple KIT Number:	0	**Kit IND:**	N
Kit Part IND:	N	**Review IND:**	Y
Unit Of Issue:	PT	**Container QTY:**	16 FL OZ
Type Of Container:	GLASS BOTTLE		
Additional Data:			

Detail DOT Information

TOP

DOT PSN Code:	ANB	**Symbols:**	
DOT Proper Shipping Name:	AMMONIA SOLUTIONS		
DOT PSN Modifier:	RELATIVE DENSITY BETWEEN 0.880 AND 0.957 AT 15 DEGREES C IN WATER, WITH MORE THAN 10 PER CENT BUT NOT MORE THAN 35 PERCENT AMMONIA		
Hazard Class:	8	**UN ID Num:**	UN2672
DOT Packaging Group:	III		
Label:	CORROSIVE		
Special Provision:	T14		
Packaging Exception:	154		
Non Bulk Pack:	203	**Bulk Pack:**	241
Max Qty Pass:	5 L	**Max Qty Cargo:**	60 L
Vessel Stow Req:	A		
Water/Ship/Other Req:	40,85		

Detail IMO Information

TOP

IMO PSN Code:	AWY		
IMO Proper Shipping Name:	AMMONIA SOLUTION		
IMO PSN Modifier:	,RELATIVE DENSITY BETWEEN 0.880 AND 0.957 AT 15 DEG C IN WATER, WITH MORE THAN 10% BUT NOT MORE THAN 35% AMMONIA BY MASS		
IMDG Page Number:	8111	**UN Number:**	2672
UN Hazard Class:	8	**IMO Packaging Group:**	III
Subsidiary Risk Label:	-		
EMS Number:	8-06	**MED First Aid Guide NUM:**	725

Detail IATA Information

TOP

IATA PSN Code:	BKD	**IATA UN ID NUM:**	2672
IATA Proper Shipping Name:	AMMONIA SOLUTION		
IATA PSN Modifier:	,RELATIVE DENSITY (SPECIFIC GRAVITY) BETWEEN 0.880 AND 0.957 AT 15 DEG C IN WATER,WITH MORE THAN 10% BUT NOT MORE THAN 35% AMMONIA		
IATA UN Class:	8	**Subsidiary Risk Class:**	
IATA Label:	CORROSIVE		
UN Packing Group:	III	**Packing Note Passenger:**	819
Max Quant Pass:	5L	**Max Quant Cargo:**	60L
Packaging Note Cargo:	813	**Exceptions:**	A64

Detail AFI Information

TOP

AFI PSN Code:	BKD	**AFI Symbols:**	
AFI Proper Shipping Name:	AMMONIA SOLUTIONS		
AFI PSN Modifier:	,RELATIVE DENSITY BETWEEN 0.880 AND 0.957 AT 15 DEG C IN WATER, WITH MORE THAN 10% BUT NOT MORE THAN 35% AMMONIA		
AFI Hazard Class:	8	**AFI UN ID NUM:**	UN2672
AFI Packing Group:	III		
AFI Label:			
Special Provisions:	P5	**Back Pack Reference:**	A12.3

HMIS HAZCOM Label

TOP

Product ID:	**AQUA AMMONIA 26 DEG BAUME**				
Cage:	5A188	**Assigned IND:**	N		
Company Name:	ASHLAND CHEMICAL CO				
Street:	5200 PAUL BLAZEL MEMORIAL PARKWAY			**PO Box:**	
City:	DUBLIN	**State:**	OH	**Zipcode:**	43017
Country:	US				
Health Emergency Phone:	606-324-1133				

Label Required IND:	Y	**Date Of Label Review:**	09/15/1990
Status Code:	C	**MFG Label NO:**	N/R
Label Date:	09/15/1990	**Year Procured:**	1989
Origination Code:	F	**Chronic Hazard IND:**	N
Eye Protection IND:	YES	**Skin Protection IND:**	YES
Signal Word:	WARNING	**Respiratory Protection IND:**	YES
Health Hazard:	Moderate		
Contact Hazard:	Moderate		
Fire Hazard:	Slight		

Reactivity Hazard: None

Hazard And Precautions

CORROSIVE! CONTAINS AMMONIA IN SOLUTION.CAUSE SEVERE BURNS TO EYES AND SKIN.MAY DAMAGE EYES.IF SKIN OR EYE CONTACT OCCURS,FLUSH WITH PLENTY OF WATER AND GET IMMEDIATE MEDICAL HELP.WEAR GOGGLES AND FACESHIELD WHEN HANDLING.REMOVE CONTAMINATE D CLOTHES LAUNER BEFORE REUSE.AVOID DUST OR FUMES.FUMES MAY CAUSE RESPIRATORY TRACT IRRITATION.HARMFUL IF SWALLOWED.BURNS ESOPHAGUS AND CAUSES ULCERATION OF STOMACH.IN CASE OF ACCIDENTAL INGESTION,GIVE 1-2 GLASSES OF WATER OR MILK.DO NOT I NDUCE VOMITING.CONSULT A PHYSCIAN.KEEP AWAY FROM FOOD PRODUCTS.USE IN ADEQUATE VENTILATION.KEEP CONTAINER TIGHTLY CLOSED AND IN DRY PLACE.AVOID CONTACT WITH SOLUTION.

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